NRG Energy
211 Carnegie Center
Princeton, NJ 08540

July 10, 2015

Securities and Exchange Commission
Division of Corporation Finance
100 F Street N.E.
Washington, D.C. 20549
Attn: Jennifer Thompson, Accounting Branch Chief

Re: NRG Energy, Inc., NRG Yield, Inc. and GenOn Energy, Inc.
Forms 10-K for the Fiscal Year Ended December 31, 2014
Filed February 27, 2015
File Nos. 001-15891, 001-36002 and 001-16455

Dear Ms. Thompson:

We hereby respond to the comments made by the Staff in your letter dated June 29, 2015 related to the above referenced filings of NRG Energy, Inc. (the "Company"), NRG Yield, Inc. and GenOn Energy, Inc. Since the Company and management are in possession of all the facts relating to the Company's disclosure, we hereby acknowledge that (i) the Company is responsible for the adequacy and accuracy of the disclosure in the filing; (ii) 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 (iii) 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. We look forward to working with the Staff and improving the disclosures in our filings.

The Staff's comments, indicated in bold, and the Company's responses are as follows:

<u>NRG Energy, Inc. Form 10-K for the Fiscal Year Ended December 31, 2014</u>

1. **Unless otherwise indicated, please apply all comments issued on NRG Energy, Inc. to NRG Yield, Inc. and GenOn Energy, Inc. as applicable.**

   We have noted below the registrant(s) for which each response is applicable.

<u>Item 7 — Management's Discussion and Analysis of Financial Condition and Results of Operations</u>

<u>Management's discussion of the results of operations for the years ended December 31, 2014, and 2013, page 64</u>

2. **Notwithstanding the changes that occurred to your segment reporting during 2014, you may need to separately discuss your Texas operations within your analysis of results if**

this is a significant portion of the NRG Business reportable segment and if it is continuing to exhibit different trends in profitability from the remainder of that segment.

To assist us in understanding why you do not discuss your Texas conventional power generation business in more detail, please respond to the following:

- **We note that gross margin as a percentage of operating revenue for the Gulf Coast region within your NRG Business segment declined approximately 200 basis points from 2013 to 2014. Please tell us whether either of your Texas or South Central wholesale operations contributed disproportionately to this decline in gross margin. If so, please tell us why your analysis of the reasons for this decline as seen on page 66 does not convey this information to your investors.**

  As disclosed on page 66 of NRG's 10-K, the primary driver of our gross margin decline was a decrease in average realized prices in ERCOT (Texas) offset partially by higher realized prices in MISO (South Central). This was comprised primarily of a significant decrease in ERCOT average realized prices of $163 million, offset partially by an increase of $23 million in MISO. The remaining explanations provided with respect to our Gulf Coast region, while combined in one table, reflect variances that are specific to either Texas or South Central. Our bilateral contracts and nuclear generation are specific to the Texas region and we disclose that our lower coal transportation and transmission costs are related to the move to MISO, which affected only our South Central facilities. The results of our Texas and South Central wholesale operations are managed by the head of our Gulf Coast region and reflect the same key drivers, including natural gas prices, weather, fuel costs and planned and unplanned outages. Accordingly, we believe we have effectively disclosed the separate impacts of both Texas and South Central on our Gulf Coast gross margin changes, where material to our results, and will continue to disclose significant drivers in future filings.

- **We note from your fiscal 2013 Form 10-K that the Texas conventional power generation business experienced operating and pre-tax losses that were material to your segmental and consolidated results in each of 2013 and 2012. Similarly, we note your Texas conventional power**

generation business experienced a pre-tax loss that was material to your segmental and consolidated results in the first quarter of fiscal 2014, the last quarter in which Texas was separately disclosed. We further note that in your earnings call for the 3th quarter of 2014, you referred to Texas as a "core market" with respect to projecting the wholesale component of your 2015 earnings guidance and discussed continuing challenges in that market. Based on the above, it appears that the operating income margin for your Texas conventional power business may continue to be significantly lower than the profitability of the remainder of your conventional power business and it may continue to materially impact your segmental and consolidated results. To assist us in understanding why you do not discuss Texas in more detail within the analysis of your operating expenses or indicate that Texas may be less profitable than other businesses, please summarize for us how your Texas competitive business performed for the full year ended December 31, 2014 and explain to us how this compared to the other geographic regions in the NRG Business segment and how it compared to your consolidated results. Further, with reference to Item 303 of Regulation S-K and SEC Release 33-8350, explain to us why management believed a more detailed discussion of the Texas competitive business operations was not necessary in the fiscal 2014 Form 10-K as part of explaining the significant underlying factors driving changes in operating income for your NRG Business segment and your consolidated results.

As described above, we have provided information with respect to the key drivers within our Texas gross margin which primarily reflect lower realized prices and gross margin from contracts, offset by higher nuclear generation from fewer unplanned outages. As detailed in the table at the top of page 66 of NRG's 10-K, within NRG Business, the regions that most significantly impacted our 2014 results as compared to 2013 were East and West, contributing $499 million and $101 million, respectively, of our total $479 million increase. These increases were primarily driven by the acquisition of EME which contributed $403 million of the total $479 million increase. Prior to 2013, our Texas region was the most significant contributor to our wholesale gross margin. Subsequent to both the GenOn acquisition in December 2012 and the EME acquisition in April 2014, our East and West regions contribute more significantly, although the amounts will vary based on seasonality, the location and availability of our facilities and power prices. We do describe Texas as "a core market" as it is one of our core markets, but our core markets include a number of markets in the East, West and South Central regions. There are many uncertainties with respect to all of our markets, and we describe many of these uncertainties within Item 1, Market Framework on p. 21, Regulatory Matters on p. 23, and Environmental Matters on p. 29 as well as within Item 7, Business Environment on p. 60, Weather on p. 61 and Other Factors on p. 62.

Additionally, as disclosed on page 70 of the NRG 10-K, other operating costs, which primarily consists of operations and maintenance expense and property tax expense, increased by $528 million, of which $326 million related to the acquisition of EME. As disclosed, $60 million of the increase related to Gulf Coast, of which $62 million was related to increases in Texas. Our description of the increase provides further explanation that the primary driver was our facilities in Texas, including STP, Gregory, WA Parish and Limestone, which are noted as being located in Texas.

We continue to believe that Texas is a core market for our wholesale business, particularly given its synergies with our retail business in Texas. We have noted, however, that the significance of its contribution to our overall results has decreased due to the size of our acquired businesses. As of December 31, 2011, Texas represented 10,745 MW out of 24,130 total domestic MW or 45%. As of December 31, 2014, Texas represented 10,559 MW out of 51,514 total MW or 20%.

<u>NRG Business gross margin, page 65</u>

3. **We note the list of quantified items that impacted the change in the NRG Business segment's gross margin on pages 66 and 76. While these tables list and quantify several items that changed from year to year, your disclosures do not identify the reasons underlying many of those changes. For example, you quantify the impact on gross margin of increased or decreased realized prices, hedged capacity prices or generation, but you do not explain why these items increased or decreased. As indicated in our interpretive releases, MD&A requires not only a "discussion" of what changed but also an "analysis" of known material trends, events, demands, commitments and uncertainties underlying those changes to provide investors with insight into why those changes occurred. Identifying the intermediate effects of these trends, events, demands, commitments and uncertainties, such as increased or decreased prices or generation, may be useful to investors; however, a thorough analysis often will involve discussing both the intermediate effects of those matters and the reasons underlying those intermediate effects. Refer to Section III.B.4 of our Release 33-8350, and revise future filings to provide better insight into the underlying drivers of changes in your gross margin.**

We respectfully acknowledge the Staffs' comments with respect to our explanations pertaining to the drivers of changes in price and/or volume. We endeavor to provide explanations that will be meaningful to our investors. Because our regions are comprised of many different facilities in various locations, running on various fuel sources and serving many different customers, there is typically no one material factor that drives the changes in price and volume. To the extent there is a material factor impacting price or volume, we disclose this in our MD&A, such as when we disclose lower generation due to the duration or timing of plant outages or due to weather conditions. With respect to price changes, there are often a number of competing factors driving these changes, which we describe on p. 61 of NRG's 10-K in the Business Environment, Electricity Prices section. We will revise future filings to provide more detailed explanations of these drivers to the extent possible.

<u>Critical Accounting Policies and Estimates</u>

<u>Goodwill and Other Intangible Assets, page 99</u>

4. **We note you performed a quantitative assessment for your NRG Texas reporting unit which resulted in this reporting unit failing the first step of the goodwill impairment test but passing the second step of the goodwill impairment test such that you recorded no goodwill impairment. We have the following comments:**

- **With respect to the most recent quantitative assessment you performed, please explain to us all significant assumptions you relied on in more detail than is disclosed in your filing. Your response should include but not be limited to explaining how you reflected in your quantitative assessment the significant drop in natural gas prices and resulting impact this has on setting the price of power.**

We utilized a discounted cash flow analysis to determine the fair value of the Texas reporting unit, which was validated through comparisons to a valuation determined by applying a market-based multiple to earnings before interest, income taxes, depreciation and amortization (EBITDA). The primary inputs to the discounted cash flow analysis were as follows:

- Gross margin was estimated utilizing market power prices driven by natural gas prices and heat rates for the first five years and NRG's fundamental view of market power prices for the sixth year (considered as "terminal year"). This reflected slightly decreasing near-term market natural gas prices offset by slightly increasing heat rates, which resulted in gradually increasing power and fuel prices over the first five years.

  - Heat rates remained relatively unchanged in the near-term, however began to rise slightly toward the end of the five-year curve and the terminal year driven primarily by microeconomic factors including the introduction of assumed carbon cost factors in the terminal year.

  - With respect to natural gas prices, most third party fundamental views agree that prevailing conditions suggest that demand will continue to lag supply, particularly over the next two years, due to the recent surge in shale production causing transformational regional shifts in supply, the proliferation of pipeline construction, and production innovation and efficiency showing no signs of slowing. However, a correction is likely to take place in the 2016-2018 window due to multiple demand side growth factors, including Mercury and Air Toxics Standard (MATS) and other regulatory retirements of coal assets and the

resultant substitution of gas-fueled power generation, cumulative industrial demand growth, and increased exports. NRG believes that the above outlook is implicit in its five-year forecast and terminal view for the Texas reporting unit.

  - Generation economics, primarily driven by the coal facilities, became slightly unfavorable beginning in the terminal year. Due to a proposed EPA carbon rule that, if enacted as proposed, would create a wide range of possible outcomes, NRG framed potential carbon outcomes through a moderate nation-wide carbon price of $10/ton beginning in 2020, the terminal year. This represents the highest probable outcome between a more aggressive nation-wide carbon price of $20/ton including prevailing disruptive technologies and no Federal carbon regulations. NRG's assessment was of both Congressional and EPA activities on GHGs which includes federal carbon prices starting later and having a different shape and impact, specifically looking like tax without free allocations, as well as the Company's previous overall uncertainty surrounding the implementation and timing of carbon legislation on the five-year forecast period.

- Operations and maintenance expenses and capital expenditures were estimated based on NRG's forecasted normal and major maintenance for the facilities for the initial five-year forecast period and normalized maintenance expenses and capital expenditures for the terminal year, representing an amount that can be grown at inflation through the life of the facility and reflects all projected expense.

- With its complementary generation portfolio, the Texas reporting unit is a supplier of power to NRG's retail business in Texas, thereby creating a more stable, reliable and competitive business that benefits Texas consumers. By backing the load-serving requirements of the retail business with NRG's generation and risk management practices, the need to sell and buy power from other financial institutions and intermediaries that trade in the ERCOT market is reduced, resulting in reduced transaction costs and credit exposures. This combination of our generation and retail businesses allows for a reduction in collateral requirements by reducing the need to hedge the retail power supply through third parties. Synergies represent the eliminated collateral requirements of approximately $815 million, with an estimated annual savings of $50 - $90 million. Synergies also include supply cost synergies of approximately $25 million per year. The Company applies the highest and best use concept and combines the Texas business unit with the Texas retail business unit and the synergies associated with combining these businesses is considered to be a market participant view of the fair value of these business units.

- The methodology for the terminal year and discount rate are disclosed in the NRG 10-K on page 100.

- **With respect to your sensitivity scenario, explain to us how you concluded using a hypothetical $0.50 per MMBtu drop in the natural gas market price for the first five year period was reasonable.**

A hypothetical $0.50 per MMBtu drop in natural gas market price represents 10% of NRG's terminal view for natural gas prices. The Company believes this drop represents a lowest case because, as discussed in our response to the first sub-question of question 4, most third party fundamental views believe that a 2016-2018 market correction is likely based on the microeconomic factors detailed above. In addition, the hypothetical $0.50 drop in natural gas

sensitivity is consistent with those used for the Company's quarterly earnings release sensitivities. Accordingly, we believe $0.50 per MMBtu represents a reasonable sensitivity scenario.

- **Explain to us in more detail, and tell us how you considered disclosing, the factors that that allowed you to pass step two of the impairment test despite the fact that you failed step one.**

The factors that allowed the Texas reporting unit to pass step two of the impairment test include the application of the Gordon Growth Model to the terminal value under the assumption that the cash flows for the Texas reporting unit continue in perpetuity for step one, while the assets within the Texas reporting unit have a finite life and related cash flows under the hypothetical acquisition method accounting that is required to be applied for step two, which results in higher residual goodwill balances. In addition, the synergies associated with the combination of NRG's wholesale generation business and retail business in Texas, as discussed in the first sub-question to question 4 above, also contribute to the Texas reporting unit passing step two. We disclose both of these factors within our disclosures on page 100 of NRG's 10-K.

- **Also tell us the percentage by which the implied fair value of your goodwill exceeded the carrying amount when you performed step two. Please consider disclosing this information to provide your investors with a greater ability to assess the likelihood of a significant impairment charge.**

The implied fair value of the Texas goodwill exceeded its carrying value by 44%, or $756 million. We will consider disclosing this information in future filings.

5. **We also note you reconciled the fair value of your NRG Texas reporting unit determined under the income approach with NRG's market capitalization. Please provide us with the reconciliation of the fair value of this reporting unit to your market capitalization, and explain the underlying reasons for the difference. Please be detailed in your response.**

($ in thousands)		As of Valuation Date		Analyst Target Price
Stock price	$	26.95	$	34.50
Shares outstanding		338,109,000		338,109,000
Equity value	$	9,112,028	$	11,664,748
Preferred stock	$	249,000	$	249,000
Debt	$	20,374,000	$	20,374,000
Business Enterprise Value	$	29,735,028	$	32,287,748
Business Enterprise Value with 20% control premium	$	31,557,433	$	34,620,697
Texas Business Enterprise Value	$	5,235,760	$	5,235,760
Texas as % of NRG		17.6%		16.2%
Texas as % of NRG with control premium		16.6%		15.1%

		Value	% of NRG
Comparison to % of Adjusted EBITDA:			
NRG Adjusted EBITDA — 2013 (Actual)	$	2,646,000	
NRG Adjusted EBITDA — 2014 (Actual)	$	3,128,000	
NRG Adjusted EBITDA — 2015 (Mid-point of Guidance)	$	3,300,000	
Texas Adjusted EBITDA — 2013 (Actual)	$	502,139	19.0%
Texas Adjusted EBITDA - 2014 (Actual)	$	291,577	9.3%
Texas Adjusted EBITDA - 2015 (Forecast)	$	447,000	13.6%

As per the above table, we reconciled the enterprise value of our Texas reporting unit to the total NRG business enterprise value, which was calculated using our market capitalization as of the valuation date and noted it ranged from 16.6% - 17.6% depending on the use of a reasonable control premium. We then compared the Adjusted EBITDA of our Texas reporting unit to the total NRG Adjusted EBITDA for historical periods and our 2015 guidance (which is detailed in the table above) and noted it ranged from 9.3% to 19.0%, which is reasonable. We did not note any significant reconciling differences.

6. **Refer to your disclosure on page 101 where you state, "If long-term natural gas prices for periods beyond 2015 remain depressed for an extended period, the Company's goodwill may become impaired in the future, which would result in a non-cash charge, not to exceed $1.7 billion, related to the NRG Texas reporting unit." In order for investors to assess the likelihood of a future impairment charge we believe you should better explain to investors the scenario (e.g. how you define an extended period) which could potentially lead to an impairment. Please tell us how you defined this term, and revise future filings for this matter.**

We acknowledge that we can better explain to investors a scenario which could potentially lead to an impairment. We find this task to be challenging given the range of uncertainties with respect to the Texas market. We define the term "extended" to mean beyond the period included within our five-year forecast and terminal year forecast. For future filings, to further clarify this disclosure and emphasize the significant impact of natural gas prices in the terminal year on our estimate of fair value, we will revise our disclosures as follows: "If long-term natural gas prices for periods beyond 2015 remain depressed for the terminal year of 20XX and beyond, the Company's goodwill may become impaired in the future, which would result in a non-cash charge, not to exceed $1.7 billion, related to the NRG Texas reporting unit."

Note 4— Fair Value of Financial Instruments

Recurring Fair Value Measurements, page 139

7. **Please explain to us how you develop a range for your significant unobservable inputs used in developing the fair value of your Level 3 positions. In this regard, we assume there could be a wide range of the forward market price assumptions used to fair value your commodity contracts. Please tell us your consideration of disclosing the weighted average of the forward market prices, similar to the illustration provided in ASC 820-10-55-103. Also tell us what consideration was given to providing a narrative description of the sensitivity of the fair value measurement to changes in unobservable inputs. Please refer to ASC 820-10-50-2(bbb) and (g).**

Historically, NRG and GenOn's level 3 positions using unobservable inputs were not a significant portion of the total fair value. Given the nature of our net derivative position, we did not believe that a significant change in market commodity prices would have a material impact on our net level 3 fair value, and as a result, did not disclose the weighted average of

the forward market prices. However, NRG will disclose, beginning with the quarter ended June 30, 2015 Form 10-Q, the information listed below related to unobservable inputs used in the valuation of level 3 positions in accordance with the guidance provided in ASC 820-10-55-103 and ASC 820-10-50-2(bbb) and (g). GenOn will provide similar disclosures as applicable. This disclosure is not applicable for NRG Yield.

"NRG's significant positions classified as level 3 include physical and financial power and physical coal executed in illiquid markets as well as financial transmission rights, or FTRs. The significant unobservable inputs used in developing fair value include illiquid power and coal location pricing which is derived as a basis to liquid locations. The basis spread is based on observable market data when available or derived from historic prices and forward market prices from similar observable markets when not available. For FTRs, NRG uses the most recent auction prices to derive the fair value."

Note 16— Investments Accounted for by the Equity Method and Variable Interest Entities, page 177

8. **We note that certain of your equity method investments have economic ownership greater than 50%. Please tell us how you overcome the presumption of consolidation and the factors considered in evaluating whether noncontrolling rights are substantive. Refer to ASC 810-10-15-8 and ASC 810-10-25.**

NRG has three equity method investments where its economic ownership is greater than 50%: Community Wind North (99%), Elkhorn Ridge (66.7%) and San Juan Mesa (75%).

We note that the accounting guidance states that the usual condition for a controlling financial interest is ownership of a majority voting interest, however ownership of a majority voting interest does not constitute a controlling financial interest if control does not rest with the majority owner. For example, the minority shareholder may have substantive participating rights such that the majority shareholder is unable to exercise control over an investee.

With respect to the three investments above, there are certain actions within each operating agreement that require unanimous approval by all members, including NRG and in each case, the other owner of membership interests. These actions include, among others, approval of the annual budget, hiring of any employees, any expenditure in the approved budget in excess of $1 million, and voluntary or permanent removal of a turbine from service. NRG considers these to be substantive participating rights and accordingly, concluded that it does not have a controlling financial interest in the investments.

Note 18 — Segment Reporting, page 180

9. **Please tell us and clearly disclose in future periodic filings, including Forms 10-Q, whether operating segments have been aggregated within any of your reportable segments. If you are aggregating any operating segments, please identify those operating segments in your response. Refer to ASC 280-10-50-21(a). Additionally, tell us whether the segmental measure of profit or loss reviewed by your chief operating decision maker (CODM) is net income/loss attributable to NRG Energy, Inc. If your CODM reviews a different single measure or multiple measures, please revise future periodic filings to more clearly disclose this information to better meet the requirements of ASC 280-10-50-29 and 50-30.**

With respect to NRG, on page 178, we disclose that our Corporate segment includes our international business and our electric vehicle business as well as our corporate activities. These represent the operating segments that have been aggregated within our reportable segments as they are immaterial individually and in the aggregate. With respect to NRG Yield, we confirm that our operating segments are the same as our reportable segments.

With respect to NRG and NRG Yield, our CODM primarily reviews a non-GAAP measure, Adjusted EBITDA, which reflects EBITDA adjusted for unrealized gains and losses on hedging activities, accretion, contract amortization and emissions expense and other non-recurring items. Our CODM also reviews the performance of our segments based on net income/loss attributable to NRG Energy, Inc. and is provided a reconciliation of Adjusted EBITDA to net income/loss by reporting segment, as certain of NRG's debt agreements include required GAAP and non-GAAP metrics based on net income/loss attributable to NRG Energy, Inc. Since net income/loss attributable to NRG Energy, Inc. is a GAAP financial measure and Adjusted EBITDA is a non-GAAP measure, we disclose in our filings net income/loss attributable to NRG Energy, Inc. as the measure of segment profit and loss, which we believe is consistent with the guidance in ASC 280-10-50-28 which states that "If the chief operating decision maker uses more than one measure of a segment's profit or loss and more than one measure of a segment's assets, the reported measures shall be those that management believes are determined in accordance with the measurement principles most consistent with those used in measuring the corresponding amounts in the public entity's consolidated financial statements."

In addition, NRG will include the following disclosure in the Segment Reporting footnote in its subsequent filings: "NRG's chief operating decision maker evaluates the performance of its segments based on operational measures including adjusted earnings before interest, taxes, depreciation and amortization, or Adjusted EBITDA, free cash flow and capital for allocation, as well as net income/(loss) attributable to NRG Energy, Inc." NRG Yield will include the following disclosure in the Segment Reporting footnote in its subsequent filings: "NRG Yield's chief operating decision maker evaluates the performance of its segments based on operational measures including adjusted earnings before interest, taxes, depreciation and amortization, or Adjusted EBITDA, and cash available for distribution, or CAFD, as well as net income/(loss)."

Note 19— Income Taxes, page 183

10. **Refer to your disclosures in your income tax rate reconciliation and uncertain tax benefits tables on pages 183 and 185. Please explain the significant "prior year position" adjustments and advise us how such adjustments impacted your income tax expense/benefit in 2014 and 2013. Also separately tell us why these adjustments were recorded in the periods they were and why they are not indicative of errors in your previous period(s) financial statements.**

For the year ended December 31, 2013, the "prior year position" adjustments to NRG's uncertain tax benefits, as disclosed on page 185 of NRG's 10-K, related to previously disclosed differences between the financial statements as compared to the federal income tax return. The $40 million reduction in uncertain tax benefits is comprised of a $29 million reduction to the federal income tax return net operating loss carryforward as well as audit resolution of a New Jersey income tax exposure of $11 million. Second, there was a benefit reflected in the federal income tax return that did not meet the "more-likely-than-not" threshold that we acknowledged and did not accrue for in our financial statements and therefore, the reduction to the federal tax return net operating loss had no impact to NRG's income tax expense/benefit. Finally, the resolution of the New Jersey income tax audit exposure was recorded as a benefit in the income tax rate reconciliation on page 183 of NRG's 10-K within the line "Recognition of uncertain tax benefits". The adjustments were disclosed in 2013 as the 2012 federal income tax return reflecting the adjustment to the NOL carryforward was filed in September of 2013. In addition, the audit of the Company's 2009 New Jersey state income tax return was concluded in 2013.

For the year ended December 31, 2014, the "prior year position" adjustments to NRG's uncertain tax benefits, as disclosed on page 185 of NRG's 10-K, relate to previously disclosed differences between the financial statements as compared to various state income tax returns. The $27 million reduction in uncertain tax benefits is mostly comprised of a $22 million reduction to various state income tax return net operating loss carryforwards as well as audit resolution of a California income tax exposure. Second, the reduction to the state income tax return net operating loss carryforwards did not meet the "more-likely-than-not" threshold and so it had no impact to the income tax expense/benefit as this was a tax return adjustment only as we acknowledged that we should not accrue for it. Finally, the resolution of the California income tax exposure had no impact to the financial statements. The benefit in the income tax rate reconciliation on page 183 of NRG's 10-K within the line "Recognition of uncertain tax benefits" reflects additional financial statement NOL resulting from the resolution of the 2007-2009 federal income tax audit. The adjustments were disclosed in 2014 as the 2013 state income tax returns reflecting the adjustment to the NOL carryforward were filed during 2014. In addition, the audit of the Company's 2007-2009 federal income tax returns was concluded in 2014.

Note 22— Commitments and Contingencies

Midwest Generation Asbestos Liabilities, page 194

11. **Please tell us the amount you accrued related to your asbestos liabilities. Further, tell us how you have complied with the disclosure requirement in ASC 450-20-50-4 to either disclose an estimate of the possible loss or range of loss in excess of amounts accrued, or provide a statement that such an estimate cannot be made. In addition, tell us if you have recorded a related insurance receivable for recoveries and the amount thereof.**

As of December 31, 2014, NRG had recorded an accrual of $53 million to satisfy asbestos litigation claims for potential damages from possible exposure to asbestos at the Midwest Generation plants. As of December 31, 2014, the Company had not recorded a related insurance receivable for recoveries. NRG has complied with the disclosure requirement in ASC 450-20-50-4, which applies to material contingencies. NRG evaluated the liability and concluded that it was immaterial to NRG's total liabilities constituting 0.18% of total liabilities. NRG recorded the accrual of $53 million on the acquisition date balance sheet of Midwest Generation when it was acquired in connection with the EME acquisition on April 1, 2014 and accordingly, there is no anticipated impact to NRG's statement of operations. NRG expects that payments for these claims will be made over an extended period of time and accordingly, the anticipated impact to its statements of cash flows is immaterial. Based on the factors described above, NRG concluded that disclosure of the accrual amount was not required due to lack of materiality.

GenOn Energy Form 10-K for the Fiscal Year Ended December 31, 2014

Note 8— Retirements, Mothballing or Long-Term Protective Layup of Generating Facilities (GenOn, GenOn Americas Generation and GenOn Mid-Atlantic)

Facilities Announced for Deactivation Due to Returns on Investment (GenOn), page 90

12. **We note that you recorded a significant impairment loss in 2014 related to certain natural gas facilities that you deactivated in January 2015. We also note that in the second table on page 90, you list several coal and natural gas facilities and units that you planned to deactivate in April and May 2015. We have the following comments:**

- **Please explain to us the economic circumstances that led to your decision to deactivate each of these facilities and units.**

  - ***Osceola generating facility*** - During 2014, GenOn determined that based on its long-term forecast, it was not economic to continue operations of the Osceola facility and concluded that it would mothball the facility if it were unable to either obtain new long-term contract(s) to sell power or sell the facility to a third party. During the third quarter of 2014, a target acquirer (Duke Energy Florida) announced plans to purchase a different facility in the area, which limited the marketability of the Osceola plant, which operates in a limited market. The Company considered this to be an indicator of impairment and performed an impairment test for these assets under ASC 360. The impairment test resulted in an impairment loss recorded in 2014.

  - ***Coolwater generating facility*** - During the fourth quarter of 2014, the Company determined that it would pursue retiring the 636 MW natural-gas fired Coolwater facility in Dagget, California. The facility faced critical repairs on the cooling towers for Units 3 and 4 and, during the fourth quarter of 2014, did not receive any awards in a near-term capacity auction and there was no interest in a bilateral capacity deal from third parties. The Company considered these to be indicators of impairment and performed an impairment test for these assets under ASC 360. The impairment test resulted in an impairment loss recorded in 2014.

  - ***Portland Units 1 and 2*** - The units were deactivated to comply with a 2013 consent order from the NJ Department of Environmental Protection requiring the cessation of coal combustion at Units 1 and 2. This was previously disclosed in the 2013 GenOn 10-K within Note 18, *Commitment and Contingencies*.

  - ***Titus Coal Units/ Niles Units 1 and 2/ Elrama Units 1, 3 and 4/ Glen Gardner/ Werner/ Gilbert CT Units 1, 2, 3 and 4*** - The decision to deactivate these units was based on management's forecasted return on investments including those necessary to comply with environmental regulations based on forecasted energy and capacity prices, expected capital expenditures, operating costs, property taxes on other factors. This includes MATS for Titus and Niles and New Jersey High Electric Demand Day (HEDD) requirements for Gilbert, Glen Gardner and Werner. The deactivations were previously disclosed in the GenOn 2012 and 2013 Forms 10-K.

- ***Shawville Units 1, 2, 3 and 4 (MATS requirements)*** - In April 2014, the decision was made to deactivate these coal units beginning on April 16, 2015 based on management's forecasted return on investment due to MATS compliance

requirements. Management had concluded the economics supported repowering the facility as a natural gas resource and is currently planning on returning the units to service in the summer of 2016.

- **Please tell us whether each of these facilities and units was deactivated on the timetable contemplated in your Form 10-K.**

Each of the facilities and units disclosed were deactivated as disclosed with the exception of the Shawville units, where management delayed the deactivation until June 2015 as a result of a MATS extension from the original deadline. The Shawville units are expected to return to service using natural gas in the summer of 2016.

- **In contrast to the facilities deactivated in January 2015, it does not appear that you have recorded any impairment losses related to the facilities and units that you planned to deactivate in April and May 2015. To help us understand this, please tell us whether you evaluated any of these facilities or units for impairment during 2014 or in 2015. If so, please summarize the results of the impairment evaluations that were performed, including explaining how you determined the fair value of these facilities and units, to assist us in understanding how you concluded that no impairment was necessary. If you did not evaluate them for impairment, please tell us how you concluded an impairment evaluation was unnecessary.**

Management completes, on an annual basis or when a triggering event occurs, an assessment to determine if a long-lived impairment analysis is required to be performed in accordance with ASC 360. The results of the assessments performed during the fourth quarter of 2014 are summarized below. In all cases, these facilities operate in PJM territory and have forward capacity obligations through their respective deactivation dates. The dates were known at NRG's acquisition of GenOn and the fair value of the facilities and units based on this knowledge were reflected on the opening balance sheet. The primary reason that no impairment was necessary for the facilities below is that the planned deactivations were reflected in the acquisition date fair value at the GenOn acquisition date and the assets were depreciated through the planned deactivation dates. Accordingly, upon deactivation, these assets were fully depreciated. For the Osceola and Coolwater facilities previously described above, deactivation was not anticipated at the GenOn acquisition date and as a result, the assets were impaired.

- ***Shawville Units 1, 2, 3 and 4*** - No indicators of impairment were identified by management. The facility is under an operating lease agreement and the fair values of leasehold improvements assigned at the time of the NRG acquisition were immaterial and depreciated through the initial April 2015 deactivation date. The decision to convert Shawville generating facility to a gas fired facility was determined under NRG ownership in May 2014.

- ***Gilbert CT Units 1, 2, 3 and 4*** - No indicators of impairment were identified by management. Gilbert will continue to operate with a CCGT and CT Unit 9. Management's forecasts and undiscounted cash flow analysis supported that no impairment indicators existed at the acquisition date.

- ***Glen Gardner and Werner*** - Management reviewed historical and current year operating results, as well as the 2015 operating budget to conclude that a triggering event did not occur and the facility's forecasted cash flows through

the deactivation date were sufficient to cover the carrying costs of the assets. Further, the useful life assigned to the facility is consistent with the deactivation date.

We hope that the foregoing has been responsive to your comments and await the Staff's response. Please contact David Callen, Vice President and Chief Accounting Officer, at (609) 524-4734, Brian Curci, Deputy General Counsel, at (609) 524-5171, or me at (609) 524-5475 if you have questions regarding our responses or related matters.

Sincerely,

/s/ Kirkland B. Andrews

Kirkland B. Andrews
Executive Vice President and
Chief Financial Officer

cc: Brian Curci, Esq., Deputy General Counsel, NRG Energy, Inc.
David Callen, Chief Accounting Officer, NRG Energy, Inc.