Date: November 16, 2012

Subject: National Emission Standards for Hazardous Air Pollutants (NESHAP) Beyond the Maximum Achievable Control Technology (MACT) Floor ('Beyond-the-Floor') Analysis for Revised Proposed Emission Standards for New Source Coal- and Oil-fired Electric Utility Steam Generating Units

From: Nick Hutson, U.S. EPA Office of Air and Radiation

To: Docket No. EPA-HQ-OAR-2009-0234

Introduction

The purpose of this memorandum is to present the data, methodology and assumptions used to conduct a beyond-the-floor (BTF) analysis for the emission limits that the Agency is proposing in the reconsideration of certain new source standards established in the final National Emission Standards for Hazardous Air Pollutants (NESHAP) for Coal- and Oil-fired Electric Utility Steam Generating Units (EGUs). This memorandum presents the estimates of the incremental pollutant emission reduction and cost that would be achieved by implementing a BTF option to control hazardous air pollutant (HAP) and HAP surrogate emissions from new and reconstructed sources and discusses any anticipated non-air quality health and environmental impacts and energy requirements.

The MACT floor level of control for new EGUs is based on the emission control that is achieved in practice by the best controlled similar source for each HAP or HAP surrogate in the different categories or subcategories. After EPA establishes MACT floor levels, CAA section 112(d)(2) requires EPA to consider whether more stringent BTF standards should be established. Pursuant to that section of the CAA, the Agency must consider "the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements..." before it may establish a standard that is based on a BTF level of control.

As mentioned, the new source MACT floor emission limits were set based on the performance of the best controlled similar source within that category or subcategory. In most of these cases, it is reasonable to expect that the very best performing source is achieving that level of control through the application of well-performing control technologies, by following a disciplined and routine maintenance schedule, and by operating in an efficient manner. For most of the new source standards addressed in the reconsideration proposal, we have not identified additional technologies or HAP emission reduction approaches that would achieve HAP reductions greater than the new source floors for the subcategories – other than multiple controls in series (e.g., multiple scrubbers in series or multiple particulate matter (PM) controls in series), which we consider to be unreasonable from a cost perspective. We are therefore proposing to adopt the floor level of control in all but one instance. We are proposing a BTF standard for hydrogen chloride (HCl) emissions from coal-fired EGUs. Details of the EPA's BTF evaluations for the new source standards proposed in the reconsideration notice are provided below.

Beyond-the-floor analysis for PM from coal-fired EGUs

It is commonly accepted that a baghouse fabric filter (FF) is the technology that provides the best level of PM emission reduction for coal-fired EGUs. Newly constructed coal-fired EGUs will be expected to install a baghouse FF to meet the new source NESHAP PM limit and the applicable New Source Performance Standard (NSPS). We have considered available options that would allow a new source to achieve greater emission reductions than those achieved in practice by the best controlled source. The EPA is aware that some EGUs have installed downstream secondary PM control devices to provide for incremental PM reductions beyond what is achieved by the primary PM control device. However, those secondary "polishing" PM control devices are most often installed for one of two purposes: (1) to augment the control of an underperforming or undersized primary control device, or (2) to allow for injection of activated carbon or other powdered sorbent so that the fly ash and the sorbent remain separated for eventual storage, disposal, or re-use. A wet ESP (WESP) may also be installed in a new coal-fired EGU (usually downstream of a wet-flue gas desulfurization (WFGD) scrubber). Although the primary purpose of the WESP would be to control emissions of condensible PM (especially sulfuric acid mist), it would be expected to also provide some small incremental reduction in filterable PM emissions. We have conducted a BTF analysis on a hypothetical new 500 MW plant burning coal with an ash content of approximately 10 percent and operating at an 85 percent capacity factor. The calculation assumed that the primary PM control device is a fabric filter with an air-to-cloth ratio of 4.0, and that it is designed to meet a filterable PM (fPM) emission level of 75 percent of the proposed emission limit of 0.09 lb/MWh.[1] Although a relatively small percentage of the coal ash would be expected to partition to the bottom ash, we assumed all of the coal ash content would exit the system as fly ash.

We then calculated the BTF incremental cost effectiveness for installation of a downstream "polishing" secondary PM control device. In this case, we assumed the downstream FF would have an air-to-cloth ratio of 6.0 and that it would provide incremental fPM control to achieve an emission that is 50 percent of the proposed emission limit of 0.09 lb/MWh. In this case the polishing PM device would remove a much smaller amount of fPM, but at a similar (though lower) overall costs than the primary PM control device. The incremental cost effectiveness was calculated to be greater than $75,000 per ton of fPM. We do not believe that this is a reasonable cost per ton removal and it does not justify the installation of the downstream secondary PM control device and, therefore, we are not proposing a BTF fPM emission limit.

Beyond-the-floor analysis for Hg from EGUs firing non-low rank virgin coal

The proposed new source mercury (Hg) emission limit for EGUs firing non-low rank virgin coal is based on the use of the three times the representative detection level (3xRDL) approach and, thus, a more stringent BTF limit would be impractical due to measurement frequency issues described in the preamble to the proposed rule. As explained in the preamble and in the associated technical support memo ("Determination of Representative Detection Level (RDL)

[1] In petitions for reconsideration, petitioners stated that operators usually target emissions that are 50 – 75 percent of the emission limitation to provide for margin of error.

and 3xRDL Values for Mercury Measured Using Sorbent Trap Technologies", which is available in the rulemaking docket, EPA-HQ-OAR-2009-0234), we do not have information available to determine at this time whether a lower Hg emission limit could be reliably measured with sufficient frequency to allow consistent and timely compliance. For this reason, we have determined that it is not reasonable to establish a BTF level of control for Hg from this subcategory.

Beyond-the-floor analysis for Hg from EGUs firing low rank virgin coal[2]

The proposed new source Hg emission limit for EGUs firing low rank virgin coal is based on the performance of an existing EGU that is equipped with advanced air pollution control technology, including injection of brominated activated carbon upstream of a FF for the control of Hg. Although it is reasonable to assume that an increase in the injection rate of the brominated activated carbon would result in better performance and, thus, lower emissions, we do not have enough information to determine whether or not the increase in sorbent would result in a reduction in emissions that is cost-effective.

The sorbent performance curve (i.e., the percent of Hg reduction versus sorbent injection rate – see Figure 1 for an illustrative example) tends to have a steep area where small increases in sorbent result in large increases in Hg removal. However, as the sorbent injection approaches its performance limitation, the curve becomes flat and large increases in sorbent are required for only small incremental improvements in Hg control.

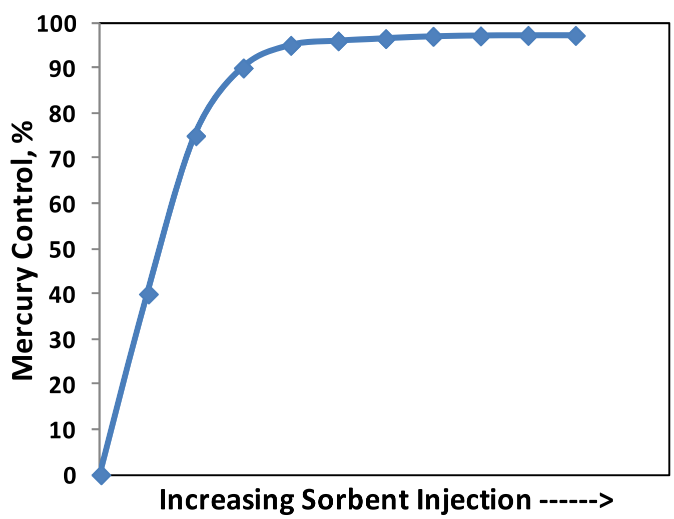

Figure 1. Example sorbent injection performance curve

The sorbent injection curve tends to be very site specific and we have no way to know exactly how the sorbent injection curve for a new low rank coal-burning source would look. We believe

[2] As stated in the preamble to the proposed rule, EPA is taking comment on whether to revise the Hg limit for EGUs firing low rank virgin coal based on the additional data in the record.

that it is likely that the performance needed to achieve a BTF level of control would require a considerable increase in activated sorbent injection. Such a significant increase would result in higher levels of sorbent mixed with the fly ash, which may affect the viability of the resulting fly ash-sorbent mixture to be recycled for beneficial use (e.g., in concrete manufacture or in road construction) and, thus, its salability. Fly ash that cannot be beneficially recycled must be land-filled at considerable cost.

A BTF analysis was performed on a hypothetical new 500 MW plant burning low rank virgin coal and operating at an 85 percent capacity factor. It was assumed that the fuel used in the EGU has an average Hg content of 26.2 lb/TBtu (which was the average Hg content of low rank virgin coal from the 2010 Utility information collection request (ICR)). Based on data from U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL) field tests, we estimate that such a facility should be able to achieve a targeted emission of 75 percent of the proposed emission limit of 0.03 lb/GWh (or 0.0225 lb/GWh, which is an approximately 92 percent reduction, coal-to-stack for the average coal) by injecting 2 lb/MMacf (pounds of sorbent per million actual cubic feet of flue gas) of brominated activated carbon sorbent upstream of a well-performing FF.[3] We have also assumed that the EGU would need to increase the sorbent injection – to 5 lb/MMacf – to achieve a BTF emission of 50 percent of the proposed emission limit (or 0.015 lb/GWh, which is an approximately 95 percent reduction, coal-to-stack).

The increase in sorbent injection needed to achieve the BTF emission may render the captured fly ash (or spray dryer absorber (SDA)/FF byproduct) unfit for beneficial reuse. If the fly ash cannot be sold (or given away in the case of SDA/FF byproduct) for beneficial reuse, then the operator must landfill the resulting byproduct-sorbent mixture at considerable cost. In the DOE/NETL study (cited earlier), this tended to increase incremental costs ($ per pound of Hg) by approximately three-fold for plants firing low rank coal.

In the cost analysis for the hypothetical new plant, we calculated incremental BTF costs ranging from $61,000 per incremental pound of Hg (assuming no byproduct effects) to $183,500 per incremental pound of Hg (assuming the sorbent renders the byproducts unusable). We do not believe that this range of potential incremental cost effectiveness is reasonable, therefore, we are not proposing a BTF Hg emission limit for new units designed for and burning low rank virgin coal.

Beyond-the-floor analysis for SO_2 emissions from coal-fired EGUs

The best performing source for sulfur dioxide (SO_2) emissions from a coal-fired EGU is a circulating fluidized bed combustor (CFB) with limestone injection for SO_2 control and a downstream circulating dry scrubber (CDS) for supplemental SO_2 control. This is expected to be a common and well-performing control configuration for new CFB combustors. Other generation

[3] Jones, A.P.; Hoffman, J.W.; Smith, D.N.; Feeley, J.; Murphy, J.T.; "DOE/NETL's Phase II Mercury Control Technology Field Testing Program: Preliminary Economic Analysis of Activated Carbon Injection", *Environ. Sci. Technol.*, 41, 1365 (2007); and Sjostrom, S.; Durham, M.; Bustard, C.J.; Martin, C.; "Activated Carbon Injection for Mercury Control: Overview", *Fuel*, 89, 1320 (2010).

technologies (i.e., PC boilers) will be expected to install advanced FGD technology such as spray drier absorber (SDA) for lower sulfur coal or a wet-FGD scrubber (WFGD) for units burning medium-to-high sulfur coals. A unit burning high sulfur coal (approximately 4 percent S, e.g., coal mined in the Illinois basin) would need to control to greater than 98 percent in order to meet the proposed revised new source MATS SO_2 limit (or nearly 99 percent in order to provide an operating margin). This level of performance is considered state-of-the-art and we believe the only opportunity to achieve a BTF emission level would be to install a downstream "polishing" scrubber. We do not believe that would be a cost effective option.

We have conducted a BTF analysis on a hypothetical new 500 MW plant burning coal with a sulfur content of approximately 4 percent and operating at an 85 percent capacity factor. The calculation assumed that the primary FGD device is designed to meet an SO_2 emission level of 75 percent of the proposed emission limit of 1.0 lb/MWh. We then calculated the BTF incremental cost effectiveness for installation of a downstream "polishing" secondary scrubber. We assumed the downstream scrubber would provide incremental SO_2 control to achieve an emission that is 50 percent of the proposed emission limit of 1.0 lb/MWh. For cost assumptions, we used information in Table 5-4 (Illustrative Scrubber Costs (2007$) for Representative Sizes and Heat Rates under the Assumptions in EPA Base Case v.4.10) from Chapter 5 (Emission Control Technologies) of the Integrated Planning Model (IPM) v 4.10 documentation. We calculated that the incremental cost effectiveness would be greater than $27,000 per ton of SO_2 removed. We do not believe that the cost of going BTF is reasonable and, therefore, we are not proposing a BTF SO_2 emission limit.

Beyond-the-floor analysis for PM from solid oil-derived fuel-fired EGUs

This analysis is very similar to that which was presented earlier for PM emissions from coal-fired EGUs. We believe that the incremental costs would be very similar to those presented for coal-fired EGUs. As with the coal-fired source, such a device would add considerable costs to the project, and the incremental cost effectiveness (i.e., the $/ton for the incremental PM reduction – which was calculated at > $75,000 per ton of fPM for new coal EGUs) would not be reasonable.

Beyond-the-floor analysis for SO_2 from solid oil-derived fuel-fired EGUs

The best performing source for SO_2 emissions from solid oil-derived fuel-fired EGUs is a CFB combustor with limestone injection for SO_2 control. Solid oil-derived fuel is most often fired in CFB boilers; and, as mentioned earlier, this limestone injection control configuration will be the most commonly used for CFB boilers. The proposed new source emission limit for SO_2 is the same as for the coal-fired EGU subcategory (1.0 lb/MWh) and the same arguments present earlier for why we do not believe that installation of a downstream scrubber is cost effective can also be made here. For coal-fired EGUs, we calculated that the incremental cost effectiveness would be >$27,000 per ton of SO_2 removed and we believe that the costs would be the same or very similar for solid oil-derived fuel EGUs. We do not believe that the cost of going BTF is reasonable, and, therefore, we are not proposing a BTF SO_2 emission limit.

Beyond-the-floor analysis for PM from continental liquid oil fuel-fired EGUs

The proposed new source fPM emission limit for continental liquid oil-fired EGUs is based on an EGU that uses an electrostatic precipitator (ESP). Distillate oil-fired facilities do not need add-on PM controls (their emissions are inherently low) and residual oil-fired EGUs cannot use FFs for PM control due to concerns about bag contamination and fire safety. Therefore ESPs are the best filterable PM control technology for liquid oil fuel-fired EGUs. The proposed new source emission limit is 0.4 lb/MWh. The performance of an ESP is based on the properties of the ash (particle size, particle resistivity, etc.). We do not have the necessary information to determine if a BTF level of performance can be obtained at liquid oil-fired EGUs and therefore, we are not proposing a BTF emission limit.

Beyond-the-floor analysis for all HAP emissions from IGCC EGUs

We have no data upon which to assess whether any other technology would provide additional control, in a cost effective manner, beyond the proposed new source emission limits for HAP emissions from new IGCC EGUs. Accordingly, we are not proposing to establish BTF emission limitations for these pollutants for new IGCC EGUs.

Beyond-the-floor analysis for HCl emissions from coal-fired EGUs

For HCl, the EPA's revised floor analysis for coal EGUs resulted in a revised MACT floor of 0.020 lb/MWh. We have estimated that a new coal-fired EGU would need to remove HCl in the range of 81.0 to 96.6 percent (depending upon the initial chlorine (Cl) content of the fuel) in order to meet this revised MACT floor emission standard. We also note that it is reasonable to expect that in most, if not all, cases, advanced FGD control technology (such as a WFGD scrubber or a high efficiency SDA) would be required as a result of other federal requirements – specifically a prevention of significant deterioration (PSD) best available control technology (BACT) analysis.

A high efficiency SDA is less costly than a WFGD, and we think it likely that some new sources will be able to comply with PSD/BACT requirements using that less expensive option. For this reason, we believe that it is reasonable to assume the minimum level of performance for HCl control from a new EGU will be equivalent to that of a well-performing SDA for purposes of the BTF analysis. We examined the level of HCl control achieved by those EGUs from the 2010 Utility ICR database that were equipped with SDA and we determined that those EGUs achieved HCl control in a range of 90 to 98 percent (coal-to-stack, depending on the coal Cl content).

In addition, because we have determined that no additional controls will be required to comply with a BTF level of control for HCl, we do not believe that there are any non-air quality health or environmental impacts or additional energy requirements associated with establishing a limit based on a BTF level of control.

We therefore are proposing to set a BTF HCl emission limit for new coal-fired EGUs at 0.010 lb/MWh. We believe that a new EGU firing lower Cl-content coal would need to achieve a minimum of 90 percent control to meet this proposed limit and that a new EGU firing a higher Cl-content coal would need to achieve a minimum of 98 percent control to meet the limit. We believe that this BTF emission limit is cost-effective because it does not involve additional cost as we expect that any new EGU will need to install at least a high efficiency SDA to comply with other CAA requirements.

We also considered a BTF emission limit by assuming installation of a WFGD scrubber, which generally achieves greater HCl reductions, but at somewhat greater cost, than a high efficiency SDA. We understand that some new coal-fired EGUs will likely be required to install this type of advanced FGD technology for SO_2 control. However, if the EGU is not required to install a WFGD scrubber as a result of the PSD BACT determination for SO_2, then the additional costs beyond those for a high efficiency SDA would be attributable only to the achievement of additional HCl emission reductions. For cost assumptions, we used information in Table 5-4 (Illustrative Scrubber Costs (2007$) for Representative Sizes and Heat Rates under the Assumptions in EPA Base Case v.4.10) from Chapter 5 (Emission Control Technologies) of the Integrated Planning Model (IPM) v 4.10 documentation. We calculated the incremental cost for the WFGD scrubber to be $11,404 per ton of HCl removed. We do not find this to be cost effective and, thus, we are proposing a BTF value of 0.010 lb/MWh.