UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION III
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Philadelphia, Pennsylvania 19103-2029

APR 20 2010

Mr. Mark Wejkszner, Manager
Air Quality Program
Northeast Regional Office
Pennsylvania Department of Environmental Protection
2 Public Square
Wilkes-Barre, PA 18711-0790

Re: Northampton Generating Company PSD/NSR Analysis

Dear: Mr. Wejszner:

On March 16, 2009, the Pennsylvania Department of Environmental Protection (PADEP) submitted a draft plan approval for the Northampton Generating Company. On June 5, 2009, the Environmental Protection Agency (EPA) submitted comments on the draft plan approval, specifically regarding the New Source Review (NSR)/Prevention of Significant Deterioration (PSD) applicability determination. In our comments we determined that there were errors in the NSR/PSD applicability analysis. Both the PADEP and Northampton responded to EPA's comments and submitted additional information on the project and the company's interpretation of certain provisions in 40 CFR 52.21. We have concluded our review of that information and would like to provide further clarification supporting our initial conclusions with respect to the project proposed in the plan approval for Northampton.

Background

The company operates a steam electric generating plant with one circulating fluidized bed (CFB) boiler that combusts anthracite culm and up to 50 percent by weight for any of the following: anthracite coal, bituminous coal, petroleum coke, paper processing residual, virgin wood chips, high carbon ash and tire-derived fuel. The current permit places a ton-per-hour cap on each of the above fuels (through a PSD analysis conducted in 2007), limits charging rate for all fuels combined to 105 tons per hour, and limits allowable heat input to 10,038,960 million British thermal units per year (MMBtu/yr) or 1146 MMBtu/hr. Continuous emissions monitors (CEMs) are in place for opacity, SO_2, NOx and CO. The source is located in a moderate nonattainment area for ozone and is considered a major source for NOx under NSR. The Northampton facility also is a major PSD source.

EPA Comments

The draft Plan Approval proposes to increase allowable heat input to 11,703,360 MMBtu/yr (1336 MMBtu/hr), keep the current annual permit limits for all pollutants except CO, and to change the CO limit from 753.4 tons per year (tpy) to 747.0 tpy to avoid being subject to PSD. An increase in heat input limits is proposed to produce more electricity.

Fine Particulate Matter (PM2.5)

On May 16, 2008, EPA published final regulations implementing NSR/PSD for PM2.5. Upon the effective date of the rule (July 15, 2008) Pennsylvania was required to immediately implement 40 CFR part 51 Appendix S for PM2.5 nonattainment areas and the revised 40 CFR 52.21 for attainment areas/unclassifiable areas. Subsequent to the effective date of the rule, EPA received a petition for reconsideration for various aspects of the rule, including grandfathering of applications submitted prior to the effective date for the purposes of using the PM10 surrogate policy. EPA has granted that petition and has also stayed the provision allowing grandfathering of applications. Therefore, all pre-construction permits issued in Pennsylvania after July 15, 2008, must implement the new rules and may no longer rely on the PM10 surrogate policy.

Neither the plan approval nor the Technical Review Memo for this project addressed the impact of the project on emissions of PM2.5. It is our assumption that PADEP and Northampton included only a PSD analysis for PM10 on the basis of EPA's former PM10 surrogate policy. As noted above, pre-construction permits in Pennsylvania may no longer rely on the surrogate policy and all plan approvals must include an NSR/PSD analysis for both PM10 and PM2.5.

PSD Applicability for CO

The company may elect to use either projected actual emissions or potential to emit (PTE) to estimate post-change emissions. CFR 52.21(b)(41)(ii)(d). The company elected to use projected actual emissions (PAE) in performing the actual-to-projected-actual applicability test as allowed under 40 CFR 52.21 (a)(2) (iv)(c). Note that for either approach baseline actual emissions (BAE) must be used and based on the information submitted, the BAE of carbon monoxide for the CFB appears to be 495.5 tpy. Below we provide general comments and analysis regarding the requirements of the applicability test using either PAE or PTE to estimate post-change emissions.

Applicability Test Using Projected Actual Emissions (PAE)

The PAE means the maximum annual rate, in tons per year, at which the CFB is projected to emit a regulated NSR pollutant in any one of the five years (12-month period) following the date the CFB resumes regular operation after the project, or in any one of the ten years following that date, if the project involves increasing the emissions units design capacity or its potential to emit that regulated NSR pollutant and full utilization of the unit would result in a significant emissions increase or a significant net emissions increase at the major stationary source. See 40 CFR 52.21(b)(41)(i).

Examples of factors that should be considered by the company in calculating PAE include, but are not limited to, projections of heat input, planned outages, projected hours of operation, and fuel mix. In addition, the company must consider all relevant information as outlined in 40 CFR 52.21(b)(41)(ii)(a) and (b), including historical operational data, quantifiable fugitive emissions, and emissions associated with startups, shutdowns, and malfunctions. For this CFB, which is a steam electric generating unit, the company is also required under 40 CFR 52.21(r)(6)(i) and (ii) to submit the bases of the applicability determination, including the baseline actual emissions, the PAE, the amount of emissions excluded under 40 CFR 52.21(b)(41)(ii)(c) and an explanation for why such amount was excluded, and any netting calculations, if applicable. For emissions excluded from the PAE, the company must demonstrate that such emissions could have been legally and physically accommodated before the project and are unrelated to the project. It is important to note that both of these requirements must be met for any emissions to be excluded. The company is required to submit all this information to the PADEP prior to beginning actual construction.

To our knowledge, the information used and other bases for the company's calculation of PAE has not been provided by the company to either the PADEP or to EPA Region 3. It is our understanding that the company has proposed a PAE level simply on the basis of calculating a level that would result in emissions increases from the project that are below the PSD significance levels. The company has not shared the expected utilization, fuel mix, demand growth, etc. and other information needed to properly make a projection of actual emissions. Therefore, EPA can not provide its views on this specific proposed applicability determination until this information is provided.

In order to properly use PAE to make an applicability calculation, the company first needs to project how they intend to operate after the change, including but not limited to how much the unit(s) will be used (demand growth) and the mix of fuels or other inputs necessary to achieve the projected use. The company must also identify the associated emissions rates based on the unit's operational capabilities following the change taking into account any legally enforceable restriction that could affect the hourly emission rate following the change.[1] Then, based on the operation or utilization projections and the associated emission rates, the company should calculate the maximum expected post-change emissions in tons per year for each NSR regulated pollutant.[2] For clarification, the following are the steps necessary to determine whether a project will result in a significant increase in emissions, using projected actual emissions.

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1 Examples of legally enforceable restrictions are MACT, NSPS, and synthetic minor permit limits that restrict the level of the pollutant at issue.

2 Because PAE is based on the company's expected operations, it is generally inappropriate to rely on allowable emissions to project post-change emissions that the unit(s) is physically incapable of achieving. For example, if an emissions unit has a 700 tpy emissions limitation, but other physical or operational restrictions on the unit would preclude it from ever emitting at this level, then it would be inappropriate to use this level for PAE.

Step 1. Calculate BAE for all existing units affected by the project.

Step 2. Calculate the maximum annual emission rate in tons per year, over the five years (in some cases 10 years) after the change, considering all relevant information, including fugitive emissions and start-up, shut-down, and malfunctions. 52.21(b)(41)(i) and (ii)(*a*) and (*b*).

Step 3. Examine the portion of post-change emissions and determine if any of such emissions above the baseline are not related to the project. If any of the emissions are not related, and the emissions unit(s) could have emitted at this level before the change if operated as projected, then those emissions may be excluded from the PAE calculation. This determination must consider such things as the currently permitted operational limits, emission rate limits, maximum firing rates, and allowable amount of each fuel that could be fired, and the expected mode of operations. A source may only subtract emissions from the maximum annual emission rate determined in Step 2 if those emissions could have been legally and physically accommodated during the baseline period and are unrelated to the change. 52.21(b)(41)(ii)(*c*).

Step 4. Subtract the BAE from the emissions derived in Step 3.

Step 5. Compare the emissions increase from Step 4 to the significance level for each pollutant.

EPA has observed that a common mistake is to assume that a unit "could" have emitted up to its permitted amount during the baseline period and this is the amount that can be excluded from the PAE. This notion and any variation of this notion is incorrect. Excluded emissions from the PAE must satisfy two criteria. First, a facility can only subtract that portion of the projected actual emissions that the unit(s) could have already physically and legally emitted during the baseline period. For instance, a facility is permitted to burn coal with a sulfur content up to two percent but actually burns coal with one percent sulfur during the baseline period. The company bases the projected actual emissions on continuing to burn one percent sulfur coal. Emissions that can be excluded would be limited to emissions associated with burning one percent coal, regardless of the limit that would allow them to burn a higher sulfur coal. In other words, the emissions that "could have been accommodated" are not defined by all the many different operating conditions that could have occurred during the baseline period; rather emissions that may be excluded are limited by the proposed operating conditions used to project emissions into the future.

Second, the facility must be able to demonstrate that excluded emissions are completely unrelated to the project. As an example, a facility that proposes to switch from one fuel to another may be able to demonstrate that all of the projected emissions after the change could have occurred during the baseline period using the original fuel type. However, for this example none of the projected maximum annual emissions from the new fuel can be excluded because all of the emissions that will occur after the project are related to the change in fuel.

Applicability Test using Potential to Emit (PTE)

40 CFR §52.21(b)(4) describes PTE as (among other things):

> The maximum capacity of a stationary source to emit a pollutant under its physical or operational design. Any... operational limitation on the capacity of the source to emit a pollutant... shall be treated as part of its design if the limitation... is federally enforceable.

The PSD rules at 40 CFR §52.21(b)(41)(ii)(d) state that PTE may be used to determine an emissions increase in lieu of PAE. Furthermore, a facility that chooses to use PTE instead of PAE for its PSD applicability determination must choose to elect a synthetic minor permit limit to avoid triggering PSD if its PTE after the project results in a significant emissions increase. In the latter situation, the regulations provide no opportunity for a source to exclude emissions in the PTE calculations. Using CO from the CFB as an example, the synthetic minor limit needed to avoid PSD for CO would be derived as follows:

BAE + [less than significance level] = 496.55 tpy + < 100 tpy = < 596.55 tpy

The resulting synthetic minor limit must be legally and practicably enforceable, consistent with EPA's policy on PTE.

Impact of Other Pollutants on PSD Applicability

The company is seeking an increase in the heat input limits to accommodate changes in CO emissions over time. As explained in the additional information submitted by the company's consultant:

> "The facility burns primarily anthracite culm and the quality of the culm available as different waste coal sites are reclaimed can vary significantly over time. As fuel quality degrades CO emissions increase. The facility contends that it needs its existing permit limit to accommodate the worst case fuel it may need to burn in the future. Indeed a review of the operating data for the plant shows that a 3 sigma analysis over a recent 39 month period shows the upper 3 sigma limit of CO emissions at 0.143 lb/MMBtu, within 35 tons of the existing permit limit at full capacity."

When this unit triggered PSD, the permit imposed BACT limits on CO of 0.15 lb/MMBtu, 172 lb/hr and 753.4 tpy. It appears that, rather than being unable to operate within the heat input restriction, the facility is actually concerned with being able to consistently comply with BACT as different waste piles are reclaimed. This is supported by the information submitted by the company. Baseline actual CO emissions for the unit are

496.55 tpy using a baseline period of 2006-2007. The average annual heat input for the same time period is 9,537,205 MMBTU. The facility is proposing to increase the heat input to 11,703,360 MMBtu, a difference of 2,166,155 MMBtu or 23 percent over the average baseline heat input. However, emissions are projected to increase over baseline by 50 percent.

Even more instructive as to the intent of this project, the company has used the actual-to- potential test for the other NSR regulated pollutants and is not proposing to change any of the current short or long term emissions limits, including the heat input limits. As the attached table shows, the increase in heat input is impossible to achieve without exceeding the permit limits for NOx and SO2, using either the actual average emissions factors or the permitted emissions factors for these pollutants. In fact, for the unit to increase the heat input to 11,703,360 MMBtu, the average NOx emission factor could not exceed 0.07 lbs/MMBtu, a 30 percent decrease from the permitted level and a 26 percent decrease from the actual average baseline emissions factor. Similarly, the average SO2 emission factor could not exceed 0.09 lb/MMBtu in order to accommodate the increase in heat input, which is 43 percent lower than the current permitted emission rate and 22 percent lower than the average baseline emission factor.

Although NSR/PSD applicability determinations are performed on a pollutant by pollutant basis, <u>any</u> restriction that would prevent a unit from actually reaching a projected level of utilization cannot be ignored. In this case, based on our analysis above, it appears the proposed increase in heat input is not achievable without exceeding the emission limits for NOx and SO2.

Conclusion

As proposed, the draft plan approval and underlying NSR/PSD applicability determination for the changes at the Northampton facility do not demonstrate compliance with federal NSR requirements. Therefore, the draft plan approval should not be issued. If you have any questions or would like to discuss these issues further, please don't hesitate to contact me at 215-814-3297 or Gerallyn Duke at 215-814-2084.

Sincerely,

Dianne McNally

Dianne McNally, Acting Associate Director
Office of Permits & Air Toxics

Attachment

Cc: Krishnan Ramamurthy, PADEP

Northampton Generating Station

Year	Actual Emissions (tons/yr)	Total Annual Heat Input (MMBtu)	Average Actual Emission Factor (lb/MMBtu)	Permit limit (lb/MMBtu)	PTE – Average Emission Factor (tons/yr))	PTE – Permitted Emission Factor (tons/yr)	Current Annual Limit (tons/yr)
NOx							
2005	401.4	8732180	0.092	0.1	538.0	585.2	449.5
2006	419.6	10003990	0.084	0.1	490.9	585.2	449.6
2007	384.0	9070420	0.085	0.1	495.5	585.2	449.6
SO2							
2005	503.1	8732180	0.115	0.129	674.3	754.9	557.8
2006	534.5	10003990	0.107	0.129	625.3	754.9	557.8
2007	485.4	9070420	0.107	0.129	626.3	754.9	557.8