pennsylvania
DEPARTMENT OF ENVIRONMENTAL PROTECTION

SECRETARY

May 6, 2014

Air and Radiation Docket and Information Center
U.S. Environmental Protection Agency
Mailcode: 2822 T
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Attention: Docket ID No. EPA-HQ-OAR-2013-0495

Re: Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units (79 FR 1430; January 8, 2014)

To Whom It May Concern:

The Department of Environmental Protection (DEP) appreciates the opportunity to submit comments on the U. S. Environmental Protections Agency's (EPA) proposed rule concerning the "Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units" (79 FR 1430; January 8, 2014). As more fully explained below, DEP questions the appropriateness of this proposal, which establishes new source performance standards (NSPS) for new electric generating units (EGUs). To this end, DEP provides the following comments on the proposal. It is important to note that the comments submitted by DEP on this proposal represent the DEP's official position on this proposal. Any comments submitted on behalf of an organization of which DEP might be a member, represent the comments of that organization and not those of DEP.

General comments

While the proposal can be characterized as an environmental regulation, the practical effect is the establishment of an energy policy for the United States. It is the opinion of DEP that such policy decisions are better left to the United States Congress and should not be made by a regulatory agency. EPA admits that there are no environmental benefits from this proposed rulemaking. This is because, even in the absence of this rule, no new coal plants would be built in future years. This argument is self-fulfilling as it proposes a rule that will impose a standard that makes it extremely unlikely that a new coal plant will ever be constructed even if market forces dictate that it would be the most economical choice. It is short sighted and unwise to create a regulation that affects energy policy on such an assumption as it limits fuel diversity and industry's ability to pursue market-based opportunities.

The proposal can only impair the reliability and affordability of domestic energy supplies by diminishing the diversity of electricity generation sources, both in terms of fuel type and technology, which we rely upon to maintain the energy security of the United States. The proposed rule acts as a de facto mandate from EPA that forces utilities to switch from coal-fired generation to natural gas in the future. The proposal can be construed as an attempt by EPA to pick "winners and losers" in the market place. It is not appropriate or reasonable for an environmental agency to make these types of policy judgments. This de facto natural gas mandate may leave U.S. consumers and businesses exposed to less reliable, more expensive, and more volatile electric generation sources in the future.

Generally, NSPS are less stringent than "best available control technology" (BACT) standards, the individually tailored emission control requirements owners or operators must meet to obtain a Clean Air Act (CAA) preconstruction permit to build or modify a major emitting facility. NSPS establishes the minimum emission control standard or "floor" for determining a facility's BACT requirements. Under Section 169(3) of the CAA, application of BACT may not result in emissions that exceed those allowed by the applicable NSPS. The point of BACT is to force individual sources to evaluate technology and controls that achieve emission reductions greater than those required for the category-wide performance standards.

As EPA noted:

> The NSPS are established after long and careful consideration of a standard that can be reasonably achieved by a new source anywhere in the nation. This means that even a very recent NSPS does not represent the best technology available; it instead represents the best technology available nationwide, regardless of climate, water availability, and many other highly variable case-specific factors. The NSPS is the least common denominator and must be met; there are no variances. The BACT requirement, on the other hand, is the greatest degree of emissions control that can be achieved at a specific source and accounts for site-specific variables on a case-by-case basis. Since an applicable NSPS must always be met, it provides a legal "floor" for the BACT, which cannot be less stringent. A BACT determination should nearly always be more stringent than the NSPS because the NSPS establishes what every source can achieve, not the best that a source could do.[1]

In the EPA's discussion on the technical feasibility of carbon capture and storage (CCS), the storage segment relies on existing data from several small scale projects and from the Permian basin injection for enhanced oil recovery (EOR). Part of this information boasts the injection of 93 million metric tons of CO_2 from 1972 to 2005 in the Permian basin, which equates to approximately 3.1 million short tons injected per year. It is also stated that 38 million metric tons of CO_2 were re-emitted from the same project, meaning that only 1.8 million short tons per year of the injected CO_2 was sequestered. This translates to 60% retention as compared to the 100% retention assumed by the EPA in establishing the 40% partial CCS requirement. An uncontrolled base plant with an efficiency of 40% and a parasitic load of 6.5% that must have a net electrical output of 500 MW would require an installed capacity of 535 MW and would emit 4.3 million short tons of CO_2[2] while operating at a 100% capacity factor.

A plant that sequesters 40% of its CO_2 emissions using the monoethanolamine (MEA) process with an identical required net electrical output and capacity factor that supplies all of the power required to sequester its CO_2 emissions using electricity provided from its own generation would require an installed capacity of 682 MW. This will generate approximately 6.3 million short tons of CO_2, capturing 2.5 million short tons and emitting 3.8 million short tons. Using the captured

[1] Letter to Mr. Richard E. Grusnick, Chief, Air Division, Alabama Department of Environmental Management from Gary McCutchen, Chief, New Source Review Section, U.S. EPA, July 28, 1987.

[2] Assuming a baseline emission of 1,851 lbs CO_2/MWh, which was determined assuming 13,000 BTU/lb of coal with a carbon content of 77%, and assuming 100% of available carbon reacts to form CO_2.

CO_2 for an EOR project, and assuming the same 60% retention rate from the Permian basin project, it would only permanently sequester approximately 1.5 million short tons of CO_2. The plant that captures and sequesters only 40% of its emissions and re-releases about 40% of the initially sequestered emissions will ultimately emit 4.8 million short tons of CO_2, **which is 0.5 million tons more than the uncontrolled plant**. Even assuming an unlikely 100% retention, the plant that sequesters 40% of its own emissions will emit 3.8 million short tons of CO_2, a mere 12% reduction from the uncontrolled plant for an equivalent net electrical output. Therefore, CCS is not currently economically viable due to the significant energy penalty nor is it necessarily environmentally beneficial.

The only control option EPA focuses upon – CCS for coal-fired units – is commercially unavailable at this time. The three U.S.-based projects cited as demonstration of commercial availability are federally funded by the Department of Energy (DOE) and therefore do not meet the definition of commercially available technology. Moreover, §15962(i) of the Energy Policy Act of 2005 expressly states:

> "No technology, or level of emission reduction, solely by reason of the use of the technology, or the achievement of the emission reduction, by 1 or more facilities receiving assistance under this Act, shall be considered to be...adequately demonstrated for purposes of [Section 111 of the Clean Air Act (CAA)]."

In fact, the State of Nebraska has filed a lawsuit in federal court for this very reason.[3] Furthermore, other projects around the world were also government-funded, and many have been abandoned because they were not viable. As EPA is aware, of the 60 "full-scale" and "large-scale" projects around the world, only 12 are operational. Of those operational projects, only three are full-scale projects, and none are post-combustion efforts. Twenty-six of the projects are for power plants, with two in the construction stage and six in the evaluation stage. The remaining 18 are in the earliest stages of development and may change in scale or technique. Of the six facilities in the evaluation stage, four are large-scale and two are full-scale. Three of the large-scale facilities are pre-combustion projects and one is a post-combustion project. One of the full-scale facilities is a post-combustion project, and the other is an oxy-combustion project.

Of the two power plant projects under construction, Southern Company's 582 MW integrated gasification combined-cycle (IGCC) power plant in Kemper County, Mississippi, is one of two IGCC plants in the nation that is slated to incorporate CCS technology using DOE funding.[4] Originally estimated to cost $2.4 billion and to be complete in May of 2014, the cost has increased to more than $5 billion and Southern will not meet its construction deadline. The Kemper County plant is designed to capture 65% of its CO_2 pre-combustion emissions.[5] It is estimated that CO_2 emissions from the combustion segment is approximately 1.6 million tons. Therefore, a total of 4.9 million tons of CO_2 is emitted, including pre-combustion, combustion, and post-sequestration emissions. An uncontrolled supercritical lignite-fired boiler with the same net output will emit 5.1 million tons of CO_2 per year.[6] Therefore, the Kemper County project with CCS will be subject to a 37% energy penalty in order to reduce CO_2 emissions by 4% compared to an uncontrolled supercritical lignite-fired power plant. In addition, according to

[3] State of Nebraska v. US EPA, Case No. 4:14-cv-3600, US District Court for the District of Nebraska.

[4] http://www.reuters.com/article/2014/01/29/utilities-southern-kemper-idUSL2N0L300U20140129.

[5] http://www.reuters.com/article/2014/01/29/utilities-southern-kemper-idUSL2N0L300U20140129.

[6] Assuming a baseline emission of 1,987 lbs CO_2/MWh, which was determined assuming 10,882 BTU/lb of lignite with a carbon content of 69%, and assuming 100% of available carbon reacts to form CO_2.

a recent article, while the EPA cites this project as a model plant to limit carbon pollution from coal plants, Southern Company officials have asked the EPA not to use it as a standard for the industry,[7] which raises considerable questions as to the viability of CCS.

The Boundary Dam project in Saskatchewan, Canada, is a 160 MW gross output coal-fired power plant that will capture 90% of the CO_2 emissions for use in EOR and results in a net output of only 110 MW, representing a 31% energy penalty. The captured emissions are 1.1 million tons of CO_2, and assuming a similar 60% retention factor from the Permian basin project, gives a net 660,000 tons of CO_2 permanently sequestered. The project is a joint venture between SaskPower and the Canadian Government costing $1.24 billion.[8]

FutureGen 2.0 is a 168 MW coal-fired power plant that would integrate oxy-combustion technology to capture CO_2 and is the DOE's most comprehensive CCS demonstration project. This project combines all three aspects of CCS technology: capturing and separating CO_2 from other gases, compressing and transporting CO_2 to the sequestration site, and injecting CO_2 in geologic formations for permanent storage and is projected to cost $1.65 billion most of which is funded by the U.S. Government and is still in the design stage.[9]

DEP's conclusion on the viability of CCS is corroborated by independent analysis. The Carbon Capture and Sequestration Alliance says that there is not the level of experience with CCS with any geologic formation, let alone a breadth of experience across a range of geologic formations and other site-specific conditions, necessary to make a determination that CCS has been adequately demonstrated. According to a paper published for the 32nd International Technical Conference on Coal Utilization & Fuel Systems (June 10-15, 2007), CCS adds more than 80% to the pulverized coal plant electricity production cost. Additionally, the Congressional Research Service notes that, to date, there are no commercial ventures in the United States that capture, transport and inject industrial-scale quantities of CO_2 solely for the purposes of carbon sequestration.[10]

If and when CCS becomes commercially viable, there is no reason to believe that it would not be available for natural gas combined cycle (NGCC) units, as well as any other major sources of greenhouse gas (GHG), and then the Agency would be able to conduct a rulemaking to set appropriate NSPS across all source categories. In fact, it may be more energy efficient to apply CCS to NGCC EGUs as opposed to coal-fired EGUs when the technology is commercially viable. Until CCS is commercially available, EPA should not pursue it for this rulemaking.

A better approach to reduce GHG emissions from EGUs is to set practical and currently achievable standards for coal-fired and natural gas-fired units that are in step with a realistic energy strategy. Instead of imposing de facto bans on the construction of new coal-fired EGUs, EPA rules should enable new advanced coal generation that pays both economic and environmental dividends by replacing old coal units with more efficient, lower emission, supercritical coal plants. We should acknowledge the economic benefits of a stable and diverse electric generation mix and realize that policies like this proposal fly in the face of that goal. Consequently, DEP urges EPA to reconsider this proposal in order to protect the environment

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[7] http://www.reuters.com/article/2014/04/02/utilities-southern-kemper-idUSL1N0MU2CJ20140402.
[8] https://sequestration.mit.edu/tools/projects/boundary_dam.html.
[9] http://www.fas.org/sgp/crs/misc/R43028.pdf.
[10] *Carbon Capture and Sequestration: Research, Development, and Demonstration at the U.S.Department of Energy,* Congressional Research Service, April 23, 2012.

while allowing the free market to determine how best to meet the future energy needs of this nation.

CCS may become the BACT to reduce CO_2 emissions for both coal-fired and natural gas-fired power plants when it becomes technically and economically feasible due to site specific factors. After the implementation of such BACT determinations, CCS may then be considered for NSPS for sources in all applicable source categories.

Viable emission standards

The emission limits for affected sources are not viable and need to be revised. The proposed NSPS regulation specifies that fossil fuel-fired units are affected facilities, and the definition of fossil fuel includes petroleum and natural gas, so separate emission limits must be established for each type of fossil fuel-fired units such as oil-fired boilers, natural gas-fired boilers and natural gas-fired simple-cycle units.

Additionally, dual fuel capability should be more adequately addressed for boilers and turbines. The requirement for a turbine to burn at least 90% natural gas to be an affected source needs to be removed. Most turbines are capable of firing multiple fuels without major modifications, so a turbine can simply fire 11% petroleum or other fuel to completely avoid the regulation.

EPA should set a performance standard of 1,000 lbs CO_2/MWh (gross) or 1,050 lbs CO_2/MWh (net) on a 12-month annual average basis for NGCC and 1,800 lbs CO_2/MWh (gross) or 1,925 lbs CO_2/MWh (net) on a 12-month annual average basis for coal-fired units. After it becomes an economically feasible control technology, CCS will become the BACT to reduce CO_2 emissions for both coal-fired and natural gas-fired power plants that are subject to the Tailoring Rule.

Establishing CO_2 limits versus CO_2e limits

DEP believes that EPA's rationale to focus on CO_2 as opposed to CO_2e appears to be well-founded. Using EIA's CO_2 data for 2012 and the Agency's estimated mass of N_2O and CH_4, the CO_2e is only 0.346% of that emitted. This percentage does not include the other GHGs, which may indicate why the Agency's estimation is a higher percentage. Estimates of the mass of N_2O and CH_4 and their CO_2 equivalent using AP-42 emission factors and based on the EPA's 2013 data for EGUs in Pennsylvania, DEP estimates approximately a 4% contribution from N_2O and CH_4. This does not account for any mass reduction of these compounds due to controls and is higher than the Agency's estimate due to the large number of circulating fluidized bed (CFB) boilers in the Commonwealth. The requirement referenced in Section XI of the preamble to monitor and report these GHGs should gather sufficient data to reevaluate this position during subsequent rulemakings.

Alternative compliance requirement

DEP concurs with the EPA proposal of a 12-month rolling average, which is more appropriate than a calendar year approach to demonstrate compliance and recommends that EPA implement this approach if a final rule is promulgated by the agency.

Use of gross output versus net output-based standards

DEP believes that a gross output-based standard is more appropriate than the net output-based standard because the units controlled by scrubbers and selective catalytic reduction devices would consume more energy than from uncontrolled units. The definition of gross output should allow for 100% of the useful thermal energy being produced and used to be included, as opposed to the 75% credit being proposed.

Compliance standard timeframe

DEP believes that the EPA's decision to provide an 84-operating-month standard runs counter to the Agency's argument that CCS is commercially available. In other words, if the technology is already available, why does the owner/operator need an 84-month period to dampen "short-term" excursions? DEP believes that a 12-operating-month standard is sufficient to dampen "short-term" excursions, once the technology is commercially available.

Inclusion of periods of startup and shutdown

DEP suggests that a calculated value be used in the case of a zero electrical load because of the undefined result of dividing by zero. A possible approach that EPA could use is to assume 100% of the useful thermal energy generated at startup and shutdown is converted into an electrical load value of MWh until the end of startup and shutdown.

Codifying regulations

Codifying the proposed regulations in their respective subparts would make referencing the appropriate NSPS easier for state and local air pollution control agencies and the owners and operators of the affected facilities. All of the applicable regulations would be in one subpart, thereby minimizing confusion. In addition, there would be no need to reproduce definitions that are already contained in the respective subparts (i.e., definition of fossil fuel). Also, if future data supports changing an emissions limitation for one type of fuel or technology, it can be addressed without opening the entire regulation to comment.

Codifying the proposed regulations in a new subpart would not cause undue burden to the owner/operator or the permitting agencies. However, as stated above, there are benefits of codifying the provisions into their respective subparts.

The applicability requirements for facilities based on electric sales alone

The EPA's proposal to base applicability on electric sales is problematic. The exemption of sources that sell less than one-third of their potential electric output or less than 219,000 MWh net electric output provides an unforeseen escape from the NSPS. Under the proposed regulation, the owners or operators of a power plant that provides 876,000 MWh annually only needs to oversize their plants by three times to ***avoid applicability***. Because the proposed rule requires a coal-fired plant to oversize by approximately 28% and install expensive auxiliary equipment in order to provide on-site sequestration at the proposed 40% level, it is more economical for plant owners and operators to oversize their potential capacity than to meet the proposed standard.

In the Agency's discussion on redefining the potential electric output, the EPA inadvertently makes the argument that oversizing the EGU gives the facility an escape from the rule. This is verified in the calculations that show how using a default value of 33% efficiency versus the design efficiency lowers the threshold used in calculating the one-third criteria.

If potential electric sales remain the metric for determining applicability, the test should be consistent for all regulated sources. DEP believes that the electric sales applicability test should be based on a three-year rolling average for both boilers and turbines. In addition, by considering a separate capacity factor of 20 to 40% for turbines, the Agency may make it easier for turbines to avoid the applicability of the rule.

Explicit exclusion of simple-cycle turbines

DEP concurs with the EPA's understanding that the majority of simple-cycle turbines will be excluded based on the applicability requirements. However, if they are not excluded for one of those reasons, it is reasonable to require that they meet the appropriate emissions limitations of the regulation.

The applicability for facilities that co-fire non-fossil fuels

DEP recommends the applicability test for facilities be the same as for the Mercury and Air Toxics Standards rule for fossil fuel-fired electric generating units, where the heat input threshold is no more than 10% fossil fuel over a three-year rolling average, or no more than 15% fossil fuel on an annual basis.

Applicability implementation issues

DEP recommends that the applicability should be based on a source's actual operations after the construction as opposed to the source's purpose at the time of construction.

Three-year operational requirement

EPA should require the owner or operator to keep records that verify its applicability status. If the owner or operator considers themselves to be subject, they should keep all records and submit all reports as required by the rule on an annual basis. If the owner or operator does not consider themselves to be affected by the rule, they should only be required to keep records that verify that they are not subject to the rule. A reporting requirement for non-affected sources should not be required; records should be maintained for five years and reported to EPA or the permitting agency upon request.

Framework for PSD permits

DEP agrees with EPA that NSPS should be the floor for determining BACT. However, EPA should set a performance standard of 1,000 lbs CO_2/MWh (gross) or 1,050 lbs CO_2/MWh (net) on a 12-month annual average basis for NGCC and 1,800 lbs CO_2/MWh (gross) or 1,925 lbs CO_2/MWh (net) on a 12-month annual average basis for coal-fired units. If and when it becomes an economically feasible control technology, CCS will become the BACT for PSD permits to reduce CO_2 emissions for both coal-fired and natural gas-fired power plants that are subject to the Tailoring Rule.

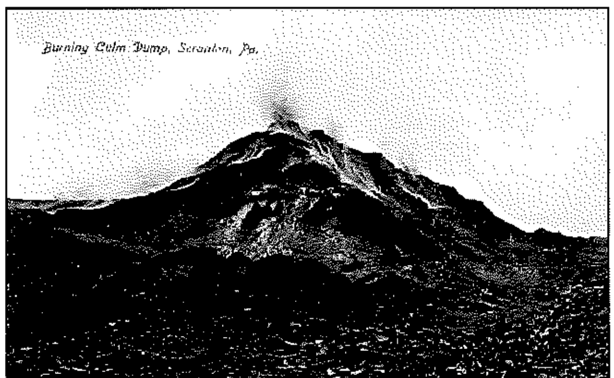
GHG permitting fees

DEP is in favor of collecting appropriate fees for administering the GHG program. State and local permitting authorities must retain the maximum flexibility in setting their Title V fee structures. While DEP disagrees with the approach of increasing the presumptive emission fee by 7% for all other Title V regulated pollutants, it should be included as an option. DEP recommends basing the cost adjustment on activities performed by DEP rather than the cost-per-ton basis. However, EPA underestimated the program implementation costs by limiting the framework to only three activities; GHG completeness determination, GHG evaluation for modification or related permit action, and GHG evaluation at permit renewal. DEP recommends EPA also consider other implementation costs such as inspection, enforcement, emissions testing, emissions monitoring and tracking.

Waste coal facilities

Notwithstanding the decision of the U.S. Court of Appeals for the D.C. Circuit in *White Stallion Energy Ctr. LLC v. EPA* (No. 12-1100), to uphold EPA's decision not to establish a subcategory for waste coal facilities, DEP believes that an exemption for this type of facility, under Section 111(b), is appropriate given the extraordinary environmental benefit provided by this technology. Moreover, should an exemption not be granted to waste coal-fired facilities, the DEP recommends a separate subcategory for this technology, which is reasonable and well-supported by DEP's comments, which follow.

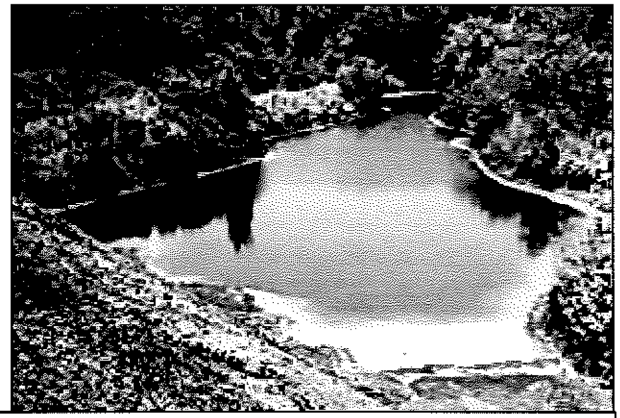
Pennsylvania has a long history of coal mining, with the first bituminous mine reported at Mount Washington in 1760 and the first anthracite mine in 1775 near Pittston. In 1889, Pennsylvania provided nearly three-fifths of the nation's coal; production peaked in 1918 at over 277 million short tons.[11] This production, however, came at a serious cost, both in lives[12] and in a lasting environmental legacy. The Pennsylvania landscape is scattered with the remains of "gob" and "boney," the cast-offs from coal sorting operations. It is estimated that approximately 180,000 acres of Pennsylvania landscape holds ***more than 2 billion tons of coal refuse***.



This postcard from 1908 highlights the historical scope of the problem of waste coal piles.

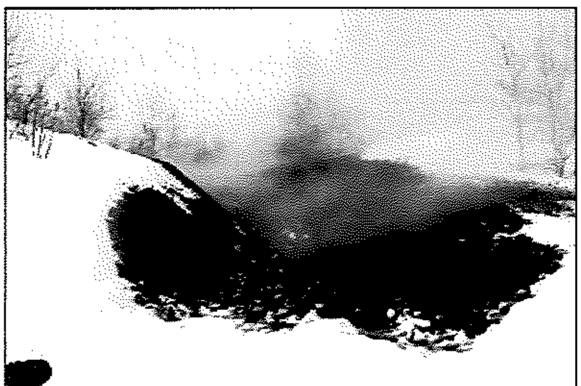
[11] National Mining Association, US Coal Production by State & by Rank, found at: http://www.nma.org/pdf/c_production_state_rank.pdf, last accessed January 29, 2014.
[12] Stories from PA History, found at: http://explorepahistory.com/story.php?storyId=1-9-18, last accessed January 29, 2014.

The land is not the only natural resource scarred by the legacy of coal mining in Pennsylvania. Acid mine drainage (AMD), which degrades thousands of miles of Pennsylvania rivers and streams, is the largest source of water pollution in the state. AMD is one of the additional



Coal refuse pile showing slow combustion and AMD from runoff at the Monahan site near Pittsburg, Kansas.

problems caused by the excess coal refuse piles across the nation.[13] Heavy metal contamination of the soil is another problem, caused by the leaching of these metals into the soil through the weathering process.



Smoking Culm Pile in Fell Township, Lackawanna County.

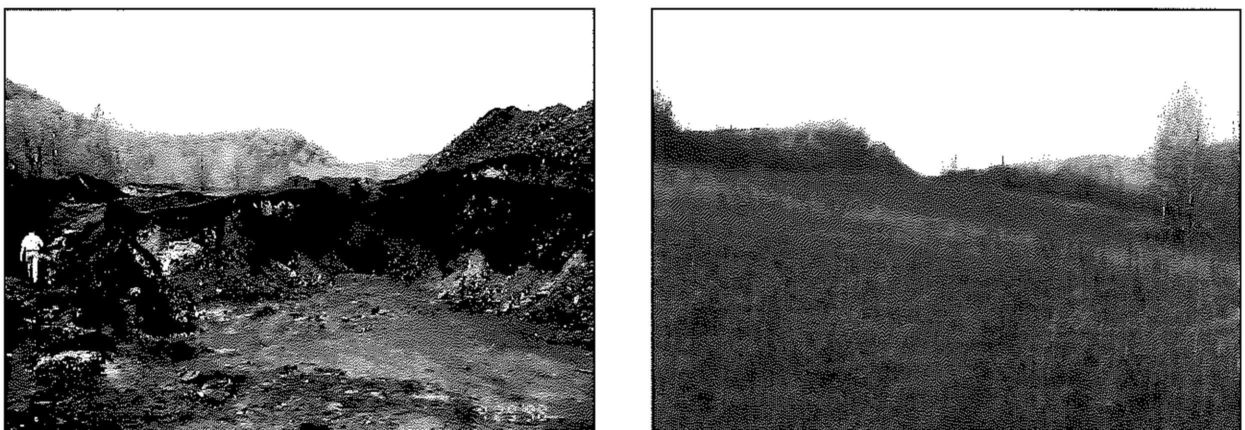
Due to the size of the piles, mining waste pile exposure to atmospheric oxygen and pressure promotes heat-generating reactions, primarily oxidation of the mining waste itself (i.e., the coal refuse piles are slowly burning). This process emits CO_2 and other air pollutants, with an estimate that approximately 0.3% of the coal refuse piles are combusting naturally. This equals approximately 9 million tons of CO_2 emitted per year, assuming the total coal refuse piles are based on production numbers where one-third of the total mass was anthracite and two-thirds was bituminous. This figure represents a total emission approximately equal to 10% of the total CO_2 emitted by Pennsylvania EGUs in 2013. The emissions would increase should a coal refuse pile ignite, as recently happened in Fell Township, Lackawanna County.[14]

[13] The pictures on the previous page are from the summary of the Monahan site found at http://www.pittstate.edu/department/biostation/moec_history.dot. Note that this site was simply graded and treated to reclaim the land without removing the waste coal. During periods of low precipitation, the author notes that the AMD problem persists.

[14] The image can be found at http://m.thetimes-tribune.com/polopoly_fs/1.1620810!/fileImage/httpImage/image.jpg_gen/derivatives/landscape_390/image.jpg.

However, since 1988, Pennsylvania has been mitigating this environmental impact by combusting coal refuse in circulating fluidized bed (CFB) boilers. Since coal refuse piles produce CO_2 naturally, the CFBs generate electric power and steam for use while providing benefits to the economy without increasing the net CO_2 emissions.[15] In addition, the ash generated through this process is alkali in nature, and is often sought for use in reclaiming abandoned mines and mine lands. Pennsylvania is home to 14 facilities with 19 CFB boilers that utilize coal refuse as their primary fuel source, accounting for approximately 1,584 MW of installed generating capacity. This installed capacity is 4.7% of the total installed capacity of Pennsylvania's EGUs; despite this, coal refuse CFBs accounted for approximately 6% of the total generation in 2013. In 2012, seven Pennsylvania waste coal facilities were listed in the Power Engineering Top 20 for Capacity, further proving that they are important base load generating units and vital for grid reliability.[16]

These facilities are literally helping to clean up the legacy scars across Pennsylvania from historic coal mining practices that preceded today's stringent environmental standards and oversight. Since 1988, these facilities have removed over 201 million tons of coal refuse, reclaimed over 7,223 acres of lands and restored hundreds of miles of streams that were impacted from acid mine runoff.[17] More than 1,000 people are directly or indirectly employed by this industry, with an economic impact to the Commonwealth in excess of $100 million.



Wesott Site in West Carroll, Cambria County (Before and After Reclamation) 25 Acres Reclaimed, 130,856 Tons Removed from 1996-1998

Due to the multiple environmental benefits of remediating coal refuse piles, EPA should establish an exemption for EGUs that burn over 75% coal refuse on an annual basis. There are tremendous advantages in utilizing coal refuse to create electricity. If net emissions caused by using mining waste to generate electricity are calculated, then a mining waste facility would produce no net GHG emissions in the long term and emissions would be no greater than the short-term emissions of a combined cycle gas plant. Remediation would stop current and future CO_2 emissions resulting from the uncontrolled combustion of waste piles. Given the significant environmental, economic and energy security advantages of utilizing coal refuse, it is imperative that these unique facilities be granted an exemption to ensure their long-term viability and to promote future capital investment into this technology.

[15] Other emissions such as CO, NO_X, VOC, and HAPs would also decrease by virtue of controlled combustion in the CFB.

[16] Hansen, Teresa; "2012 Power Plant Operating Performance"; *Power Engineering*; Vol. 12; December 2013.

[17] McNelly, Jeff; ARIPPA news release of April 22, 2013.

Should an exemption not be granted to waste coal-fired facilities, DEP recommends setting limits for bituminous gob and anthracite culm at 2,200 lb CO_2/MWh (gross) or 2,350 lb CO_2/MWh (net).

Excluding grid emergency sales from net sales when determining applicability

DEP does not agree with exempting net sales to the grid during a declared emergency for applicability purposes. This action would result in displacing well-regulated, well-controlled baseline power plants from the capacity market with uncontrolled distributed generation, thereby undoing 40 years of air pollution control efforts.

Furthermore, baseline power plants that would normally be applicable under the proposed rule could evade applicability by only bidding one-third of their capacity to the market and selling the remaining two-thirds to the emergency demand response market.

Initial performance test

DEP believes that requiring an initial performance test for all sources, including stationary combustion turbines, is consistent with DEP's requirement that all new sources must perform initial compliance tests after the shakedown period.

Co-located non-emitting sources

Including co-located non-emitting sources of electricity in the calculation of the emission standard compliance provides an additional "efficiency" measure to allow EGUs to meet the emissions limitations by decreasing their lb/MWh CO_2 emissions by increasing their net output. For example, assuming a solar intensity of 1400 W/m^2, an efficiency of 30% for the solar panels, and using 4,380 daylight hours per year, the calculated output for one acre of installed solar panels would be 7,445 MWh per year. As discussed earlier, a 535 MW nameplate capacity coal-fired facility (i.e., 500 MW output), operating 8,760 h/yr, would generate 4.3 million short tons of CO_2 while generating 4,686,600 MWh (gross) or 4,380,000 MWh (net). This drops the emissions rate on a gross output basis from 1,851 lbs CO_2/MWh to 1,847 lbs CO_2/MWh and on a net output basis from 1,979 lbs CO_2/MWh to 1,976 lbs CO_2/MWh. This is, of course, assuming that fully 50% of the total hours a day are full daylight at a maximum solar intensity with solar panels that are more efficient than those currently available; actual contributions can be expected to be much less. DEP believes that this provision will only provide marginal benefit to the affected sources.

The impacts, including potential adverse impacts, on small entities

DEP believes that the impacts of this rule on all entities, great and small, will be severe and adverse. This is evidenced by the recent lawsuit brought against the EPA by Murray Energy Corporation on March 25, 2014. In their issuance of Murray Energy Corporation's intent to sue the U.S. EPA, they state:

> "Murray Energy is the largest producer of underground coal in the United States and employs over 7,100 people in towns and cities across the country. The pressure the current administration is placing on the power sector to switch from coal to other fuels and to avoid the construction of new coal-burning facilities has

> threatened one of the nation's largest markets for coal and, in turn, the jobs and livelihoods of all those who work in and support our nation's coal industry, including Murray Energy's 7,100 employees. This is precisely the type of significant potential job loss that Congress mandated EPA to evaluate, continuously, in administering and enforcing the Clean Air Act."

In addition, DEP believes that in establishing this rule, the EPA is going to adversely affect many other industries including steel mills, cement kilns, lime kilns, petroleum refineries and other major producers of CO_2 emissions.

Significant energy action

Since the proposal envisions the implementation of unproven CCS technology, the rule acts as a de facto mandate from EPA that forces utilities to switch from coal-fired generation to natural gas in the future. DEP strongly disagrees with EPA's claim that this proposed action is not a significant energy action.

In the month of January of 2014, the Pennsylvania, Jersey, Maryland Interconnection (PJM) faced extraordinary demand due to extreme cold weather, and the recent retirement of three major Pennsylvania coal-fired power plants threatened the stability of the grid. PJM President and CEO Terry Boston issued the following statement:

> "PJM again thanks consumers for responding to our requests to conserve electricity. January was a challenging month, and the public response to our calls to conserve helped us manage the impact of the extremely cold weather across the entire PJM footprint. We also appreciate the performance of our members throughout the month of extended cold. Their cooperation and teamwork helped the region get through the challenging conditions without interruptions."[18]

The PJM predicament follows the closing of three Pennsylvania coal-fired power plants last year with others slated to close due, in large part, to proposed federal emission standards. PJM signed off on the closing of the three power plants last year, after putting aside initial reservations and contending that their closing would not negatively impact the region's power supply.[19]

Conclusion

This proposal is contrary to the historic implementation of Section 111(b) of the CAA. DEP questions the inclusion of performance standards that, from a practical standpoint, establish national energy policy that likely limits fuel diversity and likely causes considerable increases in the cost of electricity, which is inherent in the proposed rule.

[18] http://www.pjm.com/~/media/about-pjm/newsroom/2014-releases/20140131-pjm-grid-meets-month-long-challenges.ashx
[19] http://www.fierceenergy.com/story/pjm-predicament-leads-calls-investigation/2014-02-04

Thank you for the opportunity to comment on the proposed NSPS. Should you have questions or need additional information, please contact Vincent J. Brisini, Deputy Secretary for Waste, Air, Radiation and Remediation, by e-mail at vbrisini@pa.gov or by telephone at 717.772.2724. You may also contact Joyce E. Epps, Director of the Bureau of Air Quality, by e-mail at jeepps@pa.gov or by telephone at 717.787.9702.

Sincerely,

E. Christopher Abruzzo
Secretary