Basis And Rationale For Potential Subcategorization Of Coal-Fired Electric Utility Steam Generating Units

March 8, 2002

J. Michael Geers, P.E. Cinergy Corporation 139 East Fourth Street Cincinnati, OH 45202	Claudia M. O'Brien Latham & Watkins 555 11th Street, N.W. Suite 1000 Washington, D.C. 20004

TABLE OF CONTENTS

EXECUTIVE SUMMARY

At the February 5, 2002, Utility MACT subcommittee meeting, we presented several tentative bases for subcategorizing the power plant industry for purposes of setting a MACT standard. EPA and other members of the subcommittee requested additional technical information showing why these bases might be appropriate for creating power plant subcategories. This document attempts to provide that information.

As detailed below, coal-fired power plants could reasonably be subcategorized based on: (1) method of combustion; (2) coal rank; and (3) process configuration. This approach to subcategorization would yield a total of between 8 and 16 subcategories (in a source category of close to 1,100 boilers), as follows[1]:

- Fluidized Bed Combustors; and

Basis	Hot stack (above acid dew point)	Saturated Stack (above saturation temperature)	Wet stack (saturated with water vapor)
Eastern Bituminous coal	Eastern Bituminous/Hot Stack subcategory	Eastern Bituminous/Saturated Stack subcategory	Eastern Bituminous/Wet Stack subcategory
Western Bituminous coal	Western Bituminous/Hot Stack subcategory	Western Bituminous/Saturated Stack subcategory	Western Bituminous/Wet Stack subcategory
Subbituminous coal	Subbituminous/Hot Stack subcategory	Subbituminous/Saturated Stack subcategory	Subbituminous/Wet Stack subcategory
Texas Lignite[2]	Texas Lignite/Hot Stack subcategory	Texas Lignite/Saturated Stack subcategory	Texas Lignite/Wet Stack subcategory
North Dakota Lignite	North Dakota lignite/Hot Stack Subcategory	North Dakota lignite/Saturated Stack Subcategory	North Dakota lignite/Wet Stack Subcategory

---

[1]   Further analysis of the entire ICR database may allow reductions in the number of subcategories. For example, it may be possible to combine some of the five categories of coal rank. Also, subcategorization based on process configuration may not be necessary for coal ranks where mercury speciation and removal are not shown to be sensitive to process variations.

[2]   Texas lignite is also sometimes referred to as "Gulf Coast lignite." Similarly, North Dakota lignite is sometimes referred to as "Fort Union lignite."

We make the following key points in support of this approach to subcategorization:

- **The Characteristics Of Coal And Power Plant Design, Or Process Configuration, Have A Marked Impact On The Type Of Mercury-Containing Compound That Is Present In The Power Plant Flue Gas**

    ➢ There are three primary mercury-containing chemicals that are emitted from power plants: Hg^o (or "elemental mercury"); Hg^{2+} (oxidized mercury, of which $HgCl_2$ or mercuric chloride is the predominant form in flue gases); and Hg^p (particulate-bound mercury, or mercury-containing compounds that are bound to the fly ash). These compounds display different chemical properties that in turn affect the strategies that can be used to remove them from power plant flue gas.

    ➢ All coal contains low concentrations of mercury. In the very high temperatures of a power plant boiler combustion zone, all of the mercury in the coal is vaporized, and exists as elemental mercury.

    ➢ Chlorine content of coal is a major predictor of the specific mercury-containing chemicals that will be found in the flue gas. Mercuric chloride can be formed through the reaction of atomic chlorine and elemental mercury in relatively low temperature flue gas. Where there is less than 100 ppm chlorine in the coal, however, little mercuric chloride will be formed. Where there is greater than 500 ppm chlorine in the coal, mercuric chloride may be the predominant form of mercury in the flue gas.

    ➢ Temperature is also a critical factor influencing the generation of mercuric chloride, and thus, high levels of oxidized mercury. At temperatures above 500^oF (260^oC), flue gas mercury typically remains in the elemental form, even if ample chlorine is present to allow for formation of mercuric chloride.

    ➢ Other constituents of the flue gas – including fly ash composition, amount of unburned carbon, the presence of iron oxide, and other factors – to a lesser degree may influence the formation of mercuric chloride.

    ➢ At flue gas temperatures below 500^oF, coal composition – including chlorine content, ash composition and the presence of compounds such as iron oxide – is the dominant factor in determining the formation of mercuric chloride. At temperatures above 500^oF, mercury speciation is determined primarily by temperature, and elemental mercury is expected to be the dominant form.

    ➢ Much less is known about particulate-bound mercury. Levels of particulate-bound mercury appear to increase with increasing chlorine content of coal and increasing unburned carbon in fly ash. EPA postulates that particulate-bound mercury is composed primarily of oxidized mercury compounds.

- **The Statute, Legislative History, Case Law And Agency Precedent All Establish That EPA Has Ample Legal Authority To Subcategorize Coal-Fired Power Plants On The Bases Proposed In This Paper**

  ➢ *Statutory Language.* Clean Air Act § 112 grants EPA broad discretion to establish "categories and subcategories" of sources to be regulated under Section 112, and further allows EPA to "distinguish among *classes, types and sizes of sources* within a category or subcategory" when establishing MACT standards. Congress's use of the broad terms "type," "kind," and "size" shows that EPA is intended to have broad discretion in the appropriate factors that warrant distinguishing among sources for purposes of setting MACT floors and MACT standards.

  ➢ *Legislative History.* The legislative history makes clear that Congress intended EPA to distinguish among classes, types and sizes of sources under three core circumstances: when differences among sources affect (1) the feasibility of air pollution control technology; (2) the effectiveness of air pollution control technology; and (3) the cost of control. Subcategorization is the primary mechanism that allows the Agency to account for the fact that distinctions among classes, types and sizes of sources may have a very real impact on the feasibility of a given control technology, the effectiveness of that control technology, and the cost of control.

  ➢ *Case Law.*

    ✓ *Sierra Club v. Costle*, 657 F.2d 298 (D.C. Cir. 1981), specifically addressed – in the context of CAA § 111 – the scope of EPA's authority to "distinguish among classes, types and sizes of sources." Based on this statutory language, the Court held that EPA could set variable standards based on differences in the sulfur content of different types of coal.

    ✓ In finding this approach allowable because "the text of the statute nowhere forbids a distinction based on sulfur," the Court concluded that EPA has the power to vary standards on any reasonable grounds that is not expressly prohibited by the Act: *e.g.*, fuel type (as in *Sierra Club*), process configuration or achievability.

    ✓ The Court also found that lack of achievability is not necessary for justifying variable standards, implicitly concluding that differences among sources that affect achievability *would* be a reasonable ground for differentiating among sources.

    ✓ Because Congress adopted *identical* language in Section 112 after the Court's decision in *Sierra Club*, the D.C. Circuit's broad interpretation of this language must be given controlling weight. *See Bragdon v. Abbott*, 524 U.S. 634, 645 (1998).

➤ *Past Practice.* EPA's past practice has been consistent with this interpretation of the Act. The Agency has subcategorized sources in numerous industrial categories, from which it is possible to glean several principles that appear to govern the Agency's decision making with regard to creation of subcategories.

  ✓ EPA has subcategorized sources where differences result in different types or concentrations of uncontrolled HAPs;

  ✓ EPA has subcategorized sources where differences affect the applicability of control technology; and

  ✓ EPA has subcategorized sources where differences affected the *performance* of control technology and, hence, the achievability of the MACT standard (*e.g.,* where different processes are not amenable to the same level of control).

➤ Both the text of CAA § 112 and the legislative history make it clear that EPA may tailor MACT standards to take into account pertinent differences among sources. Subcategorization is the primary mechanism for tailoring standards, since it allows the grouping of facilities on the bases specified in the statute and according to the factors that Congress enunciated in the legislative history, including cost and feasibility and effectiveness of control technology.

➤ The statute uses the broad terms "class," "type" and "size" when identifying the bases on which EPA may distinguish among sources, evidencing – as the Court found in *Sierra Club v. Costle* – an intent to allow EPA to look broadly at the many factors that may affect the cost, feasibility and effectiveness of pollution control for different sources. EPA's past practice is consistent with this interpretation of the Act.

- **EPA Should Subcategorize Coal-Fired Power Plants Based On Their Method Of Combustion**

  ➤ Fluidized bed combustors utilize a fundamentally different process for burning coal as compared to pulverized coal boilers. Instead of introducing pulverized coal and air into the middle of the boiler, the fluidized bed process introduces relatively large coal particles to a bed of sorbent or inert material at the bottom of the boiler through which sufficient air flow is introduced to result in the mixture becoming fluidized. That different process results in substantial differences in design, construction and operation of the unit, including:

    ✓ Conventional boilers simply mix fuel and atmospheric air. Fluidized bed combustion units burn coal in a fluidized bed of solids that typically contains materials for absorbing sulfur dioxide and ash.

    ✓ Because they combust much larger particles of coal, fluidized bed combustors have different coal pulverizing and crushing equipment.

- ✓ Because the combustion air has to lift and fluidize the solids bed, the fans in a fluidized bed combustor must be more powerful.

- ✓ The combustion temperatures in a fluidized bed combustor are in the range of 1,500-1,650^{o}F, rather than 2,500^{o}F as in a conventional boiler.

- ✓ In fluidized bed combustion, coal ash does not become molten, resulting in vastly different ash handling systems.

- ✓ Fluidized bed combustors can burn a wide variety of fuels, including many that are too poor in quality for use in conventional firing systems.

- ✓ Because of lower combustion temperatures and gas velocities, the construction of a fluidized bed combustion unit is vastly different than a conventional unit.

➢ Because a conventional boiler could not be converted to a fluidized bed combustor without essentially completely rebuilding the unit, fluidized bed combustors constitute a different "class" or "type" of utility steam generating unit within the meaning of CAA § 112(d)(1).

➢ The differences between fluidized bed combustors and conventional boilers have significant implications for mercury removal efficiency. Although the reasons are not well-understood, fluidized bed combustors can achieve greater mercury reduction than pulverized coal power plants – even when the same particulate controls are used. Whatever occurs in the fluidized bed combustor, however, cannot be replicated in conventional coal boilers because of their fundamentally different technology – such that the control technology used in a fluidized bed combustor is *not applicable* to conventional boilers. Moreover, the level of control that is *achievable* with fluidized bed combustors differs from what is achievable with conventional boilers. Under such circumstances, EPA's past practice has been to create separate subcategories, and it would be reasonable to do so here as well.

- **EPA Should Subcategorize Coal-Fired Power Plants Based On Their Coal Rank**

  ➢ *Coal Rank.* The properties of coal can vary widely from seam to seam, mine to mine and even within mines. Nonetheless, the ASTM method of classifying coals by "rank" generally is successful in identifying some core common characteristics that have implications for power plant design and operation.

    - ✓ Lignites tend to have low heating value and high moisture and volatile contents. Bituminous coals typically have lower moisture and volatile content, and a higher heating value. Subbituminous coals range in the middle of the other two.

✓ "Grindability" – or the ease of pulverization of coal – also varies by coal rank. Coals with greater moisture – particularly lignite coals, but also subbituminous coals – have lower grindabilities.

✓ Ash content also shows general trends based on coal rank. Eastern bituminous coals generally contain from 5 to 15% ash, while the western subbituminous coal ash content may range from 5 to 50% by weight. Texas lignites also contain up to 30% ash.

✓ The constituents of ash – while they vary over a wide range for different coals – show characteristic differences between the high rank Eastern bituminous coals and the lower rank Western coals. Bituminous coals typically will have higher levels of silica, aluminum and iron; subbituminous and lignite coals generally have higher levels of calcium, magnesium and sodium.

➢ *Impact Of Coal Rank On Plant Design.* The three most important factors in modern boiler design are the steam conditions, fuel and environmental constraints. The most significant variation is differences in the types and range of fuels to be fired, which requires changes in the details and overall arrangement of boiler components.

✓ Fuel type is so important that plant designers and manufacturers expect to be provided with a complete list of each specific coal presently available or planned for future use, along with complete chemical and ash analyses so that they can properly design and specify plant equipment.

✓ The type of coal to be burned has the following impacts (among others) on power plant design:

- *Pulverizers.* The type of coal strongly influences pulverizer design. Pulverizers grind coal to the proper fineness required for firing in the boiler and use hot air to completely dry the coal particles prior to combustion. Pulverizers must be sized to process sufficient coal to meet the thermal requirements of the boiler – such that pulverizer size is tied to coal type. Pulverizers also are designed to achieve the desired coal fineness – a factor that depends primarily on coal characteristics and how they affect coal combustion in the furnace. (High rank coals need to be pulverized to a finer size than coals of lower rank.) Pulverizer design must consider the grindability of the coal – another factor that is tied to coal rank. And because more heat is required to dry wetter coals (like lignites and subbituminous), moisture influences pulverizer air inlet temperature.

- *Boiler Size and Design.* Coal rank similarly influences boiler size and design. First, the ignition stability in the boiler varies directly with the ratio of volatile matter to fixed carbon. Low-volatile coals may require support ignition to enable them to burn in suspension. Second, and

more importantly, the characteristics of the ash at the various temperatures encountered in the furnace play a critical role in boiler design. Both amount of ash and ash characteristics vary based on coal rank.

- The sizing and configuration of the furnace must accommodate the combustion and slagging/fouling characteristics of the coal. Sufficient furnace volume must be available to enable the fuel to burn with the minimum amount of slag formation and very little unburned carbon in the ash. If a boiler combusts a fuel it is not properly configured to burn, uncontrolled ash deposits can develop that block flow passages in tube banks, impeding gas flow and/or causing large slag deposits to form, then fall, causing extensive damage to the boiler.

- *Convective Section Design.* The flue gas velocity in the convective section must be limited to control erosion – with the maximum velocity determined by the magnitude and relative abrasiveness of the ash. Ash composition and slagging potential also establish the upper limit on furnace exit gas temperature, to minimize the potential for slagging in the radiant superheater and the convection surface. Ash characteristics also affect the type of soot blowers installed on the boiler. All of these characteristics can be generally related to coal rank.

- *Particulate Controls.* Coal characteristics also influence the design of the plant's particulate control system. Determining the appropriate ESP size and collection plate spacing depends upon the quantity of the particulate sent to the precipitator, particle size, particle composition and gas flow velocity. In addition, certain fuel characteristics and ash constituents, such as moisture, sulfur, sodium, silica and potassium, change the electrical resistivity of an ash (and thus change its collectibility), impacting the necessary size and design of the control device.

✓ Thus, the type of coal to be burned in the boiler has a major impact on plant design. While plant design has certain core commonalities, *each individual boiler is designed to burn specific coals with specific characteristics*. If a company wants more fuel options, those characteristics have to be built into the initial design – and will come at a cost of other plant limitations.

➢ *Impact Of Coal Rank On Mercury Speciation and Control.* Coal rank has a significant influence on which mercury compounds are present in the flue gas – which in turn affects the ability of existing technologies to effectively remove the mercury from the flue gas.

- ✓ In general, subbituminous and lignite coals tend to have low chlorine content. As a result, the flue gas from subbituminous and lignite coals is expected to contain almost entirely elemental mercury.

- ✓ Bituminous coals typically have higher chlorine content – such that oxidized mercury can form if the right conditions are present in the flue gas. For Eastern bituminous coals, in particular, the speciation of mercury typically depends less on chlorine content (*i.e.,* coal rank) and more on process configuration.

- ✓ The effectiveness of air pollution control devices at removing mercury depends to a large extent on the type of mercury compound in the flue gas. Particulate controls are very good at removing particles, such that any particulate-bound mercury will be effectively removed by these control devices.

- ✓ Flue gas desulfurization devices can be moderately to very effective at removing ionic mercury, but will remove essentially no elemental mercury. Cold-side ESPs have some limited effectiveness at removing ionic mercury, but remove essentially no elemental mercury. Because of the operating temperatures of hot-side ESPs, they will remove less ionic mercury than cold-side ESPs, and essentially no elemental mercury.

- ✓ Fabric filters also have some effectiveness at removing ionic mercury. While the data suggest that these units may be able to remove some elemental mercury, a more probable explanation is that, with certain low chlorine content coals, the ash has sufficient unburned carbon to allow adsorption or solid catalyzed reactions to occur within the filter itself. Spray dryers, when used in combination with fabric filters, can be highly effective at removing ionic mercury, although this technology combination does not appear to be able to remove elemental mercury.

➢ *Rationale For Subcategorizing Based On Coal Rank.*

- ✓ The Act grants the Agency authority to "distinguish among classes, types and sizes of sources," language which the D.C. Circuit found encompasses fuel type. Even beyond that, however, it is clear that coal type has important implications for the overall design of the unit, and coal rank provides a useful, broad indicator of required differences among units resulting from the burning of different coals.

- ✓ Coal rank can predict the chlorine content of coal and, thus, which mercury-containing chemicals may be predominantly present in the flue gas. In prior MACT standards, EPA has created separate subcategories where differences among sources resulted in different chemical emissions. It would be appropriate to do so here as well.

✓ Subcategorization based on coal rank is particularly appropriate because the specific mercury-containing compound strongly influences the *effectiveness* of existing control technologies. In numerous past MACT standards, EPA has created subcategories where differences among sources affect the performance of control technology and, hence, the achievability of the MACT standard. Adopting a similar approach here would be consistent with the language of the statute, the legislative history, case law and Agency precedent.

➢ *Coal Blending.* Although some plants can either switch or blend coals, significant constraints apply in either case.

✓ Fuel switching can cause serious operating problems, such as reduced steam capacity, increased slagging and fouling, and poorer ignition stability. Some boilers, because of their initial design specifications and choices, are more flexible to fuel blending or switching. However, fuel switching is not something that typically can be accomplished unless accompanied by extensive plant modifications – potentially including changes to the coal handling, fire protection and pulverizer systems, the size, location and spacing of pressure parts and combustion equipment, and the flues, ducts, fans, electrostatic precipitator and ash handling system.

✓ Many of the same problems seen with coal switching also can occur in a coal blending context. Where the coal to be blended has properties that differ from the coals for which the plant was designed, blending can cause significant operational problems. Indeed, some coals may be unacceptable for use at a particular plant, while others will be limited in the degree to which they can be used. Coal blending may also require some substantial operational changes at the plant. Thus, the degree to which coal blending can occur at an individual plant is limited by the plant design – and particularly, the coals which the plant was designed to burn and the compatibility of the blended coal's properties with the original design parameters.

• **EPA Should Subcategorize Coal-Fired Power Plants Based On Their Process Configuration**

➢ *Process Configuration.* Process configuration refers to what post-boiler equipment is installed on the plant, and the sequence in which it is installed. Coal-fired units are designed and constructed with different process configurations because of the site-specific requirements or constraints placed on the initial design of the unit. Changing from one process configuration to another requires large-scale and expensive revamping of the plant.

✓ There are three basic types of process configurations.

- *Hot Stack.* Plants with a hot stack process configuration have an exit temperature above the acid dew point – the temperature where sulfuric acid begins to condense from a vapor to a liquid in the flue gas. In a

hot stack process, the flue gas temperature is kept high enough to prevent acid condensation and the subsequent corrosion it causes. This protects a large portion of the boiler plant components such as air heaters, ductwork, particulate control devices, fans and stacks. Hot stack units generally do not have air heaters, particulate controls, ductwork and other components that are made of corrosion-resistant materials. As a result, if acid is allowed to condense, it can cause significant corrosive damage to components and structures.

- Hot Stack units have a stack temperature of greater than 275°F and a typical process configuration of: boiler; air heater; particulate control device; induced draft fans; stack.[3]

- *Saturated Stack.* In a Saturated Stack, the flue gas exits the stack at a temperature below the acid dew point but above the water saturation temperature. Because they remove much of the sulfur oxides from the flue gas, these units avoid the corrosion associated with operating below the acid dew point. Saturated stack units typically have a dry scrubber or spray dryer to remove sulfur dioxide. Spray dryers, however, have a lesser SO_2 removal capability than wet scrubbers and therefore are limited to use with lower sulfur fuels.

- Saturated stack units have the following process configuration: boiler; air heater; sulfur dioxide control device; particulate control device; induced draft fans; stack.

- Saturated stack units differ significantly from hot stack units because: (1) they need facilities to process the slurry of chemical reagent and water; (2) there must be sufficient residence time for complete evaporation of the water in the slurry; (3) because the flue gas contains reagent as well as fly ash, the particulate control must accommodate a much higher and chemically different particulate loading; and (4) the fans and associated equipment must accommodate an additional pressure drop.

- *Wet Stack*. In a Wet Stack configuration, which includes wet scrubbers and some other configurations, flue gas will exit the stack at the water saturation temperature. Because the flue gas is below the acid dew point before sulfur oxides are removed, these units commonly use higher alloy steels and other materials to prevent corrosion in the scrubber vessel. In addition, a wet stack must be built of corrosion resistant materials, such as acid-resistant brick.

---

[3] However, in some cases, the particulate control device may be before the air heater.

- Wet stack units have the following process configuration: boiler; air heater; particulate control device; induced draft fans; SO$_2$ control (scrubber); stack.

✓ There are significant differences between these process configurations in terms of equipment and materials of construction. While it is physically possible to reconfigure a unit of a given process configuration to another, doing so will typically require extensive reconfiguration of the existing equipment, or, in many cases, outright replacement of that equipment. For example, the addition of a spray dryer will not only require the addition of the spray dryer vessel itself, but would also require a complete retrofit of the particulate control device and auxiliary equipment to withstand the higher particulate loadings.

➤ *Impact Of Process Configuration On Mercury Speciation and Control.* Process configuration has a significant influence on which mercury compounds are present in the flue gas – which in turn affects the ability of existing technologies to effectively remove the mercury from the flue gas.

✓ Where there is more than 500 ppm chlorine in the coal, the form of the mercury is determined primarily by the temperature of the flue gas. Because process configuration determines flue gas temperature, it in turn becomes the determining factor in the form of mercury that is present in the flue gas, assuming sufficient chlorine is present in the coal to allow formation of ionic mercury.

✓ As described above, the effectiveness of air pollution control devices at removing mercury depends to a large extent on the type of mercury compound in the flue gas. Particulate-bound mercury can be removed effectively by most particulate control devices. No commercially-used control devices effectively remove elemental mercury, and current controls have variable effectiveness at removing oxidized mercury.

✓ Process configuration can be a useful indicator of the flue gas temperature, which in turn impacts the type of mercury compound that will be formed in the flue gas. The type of mercury compound in turn determines the effectiveness of air pollution control devices at removing mercury from the flue gas. Thus, process configuration impacts the effectiveness of mercury removal technologies.

➤ *Rationale For Subcategorizing Based On Process Configuration.*

✓ For the same reasons that it is appropriate to subcategorize based on coal rank, it is appropriate to subcategorize based on process configuration. In numerous past MACT standards, EPA has created subcategories where differences among sources affect the *performance* of control technology and, hence, the achievability of the MACT standard. A similar approach is warranted here.

Congress contemplated that EPA would distinguish among sources types where differences affect the feasibility and effectiveness of control. Here, the removal efficiency that can be achieved does not depend on how well a source operates and maintains its pollution control equipment, but rather on what chemical form the mercury takes when it reaches the air pollution control device.

✓ The Agency's coke oven battery MACT standard is particularly illuminating. There are two different types of coke oven batteries, both of which use exactly the same chemical input (coal), employ the same chemical process (destructive distillation), produce exactly the same output (coke), and have the same type of emissions (coke oven emissions). Yet EPA established separate standards for by-product and nonrecovery coke oven batteries because better control is *achievable* for nonrecovery coke oven batteries than for by-product coke oven batteries. Implicit in EPA's creation of differential standards is a conclusion that MACT standards were not intended to require existing sources to completely change their processes.

✓ The Agency should similarly subcategorize power plant sources based on their process configuration. The type of process configuration has a critical impact on mercury speciation and, hence, on effectiveness of removal and achievability of the standard. MACT standards were not intended to – and should not – result in sources being required to fundamentally reconfigure their plant processes. Accordingly, subcategorization is appropriate.

✓ It may be, however, that subcategorization based on process configuration is not necessary for subbituminous and lignite coals. For these coals, process configuration may not have a substantial impact on the effectiveness of control technology – and hence the achievability of the standard. But for bituminous coals, process configuration will be the predominant influence on control technology effectiveness and standard achievability – making process configuration a highly appropriate basis for subcategorization of plants burning this type of coal.

I. INTRODUCTION

At the February 5, 2002, Utility MACT subcommittee meeting, we presented three tentative bases for subcategorizing the power plant industry for purposes of setting a MACT standard: (1) method of combustion (fluidized bed combustors versus conventional boilers); (2) coal rank (bituminous, subbituminous, lignite); and (3) process configuration (defined in terms of the flue gas stack exit temperature). EPA and other members of the subcommittee requested additional technical information showing why these three bases might be appropriate for creating power plant subcategories. The following document attempts to provide that information.

First, the document discusses mercury chemistry in power plant boilers, with a focus on how coal properties and plant configuration affect the type of mercury-containing compound that will be present in the boiler. Second, the document discusses the legal standard for subcategorization, analyzing the statutory standard, legislative history, case law and EPA precedent.

Third, the document discusses the potential bases for subcategorization, explaining the technical differences among sources in the different categories and why those differences are relevant to the mercury MACT standard. Thus, the document explains how fluidized bed combustors differ from conventional coal-fired units, how those differences affect mercury removal, and why subcategorization is warranted. Similarly, for coal rank, the document explains what coal rank is, describes the many ways that coal rank influences power plant design, discusses how coal rank influences mercury chemistry and the potential for mercury removal from the flue gas and explains why subcategorization on this basis is appropriate. Coal switching and coal blending also are discussed. Finally, the document explains what is meant by process configuration, how process configuration determines the final flue gas temperature, how final flue gas temperature affects mercury chemistry and the potential for mercury removal from the flue gas, and why subcategorization is appropriate.

In sum, we believe that EPA legally can – and as a policy matter should – create the following subcategories of power plant boilers: method of combustion, coal rank, and process configuration. Doing so would result in between 6 and 16 subcategories in a source category of almost 1100 units – for an average of approximately 70 to 180 units per category.

II. MERCURY CHEMISTRY IN POWER PLANT BOILERS

Characteristics of the coal being burned and the power plant design or process configuration have a marked impact on the type of mercury-containing compound that is generated during plant operation. The two factors that have the greatest impact on the chemical structure of mercury in the flue gas are the chlorine content of coal and the final temperature of the flue gas. Other factors, however, such as sulfur and iron content, and amount of ash (also known as "LOI") also can have a significant impact on mercury speciation. The following is a brief discussion of mercury chemistry in power plant boilers, and the factors that affect the chemical structure of mercury in flue gas and, hence, the feasibility and effectiveness of removal technologies.

There are three primary mercury-containing chemicals that are emitted from power plants: Hg^o (or "elemental mercury"); Hg^{2+} ("oxidized" or "ionized" mercury, of which mercuric chloride ($HgCl_2$) is the predominant form in flue gases)[4]; and Hg^p (mercury-containing compounds that are bound to fly ash, commonly referred to as "particulate-bound mercury"). While all three compounds contain mercury, it is important to recognize that they are different chemicals and as such, display different chemical properties that in turn affect the strategies that can be used to remove them from power plant flue gas. For example, mercuric chloride exists as crystals, white granules or a white powder at room temperature; it melts at 276°C and volatilizes at 302°C, is relatively soluble in pure water and is more soluble in boiling water or water containing HCl or alkali chlorides.[5] Elemental mercury, in contrast, is a silver-white liquid at room temperature, volatilizes at 356°C and is highly insoluble in water.[6] "Particulate" mercury represents the mercury bound to the fly ash. Much less is known about the properties of particulate mercury.[7]

All coal contains low concentrations of mercury. In the very high temperatures of a power plant boiler combustion zone (typically 2500-2800°F), all of the mercury in the coal is vaporized, and exists as elemental mercury. Concentrations typically range from 1 to 20 ug/dscm.[8] At the furnace outlet, where temperatures are still generally around 2000°F, thermodynamics predict that all of the mercury will continue to be present in the elemental form. Oxidation reactions may occur, however, as the gas cools after combustion.[9]

Although equilibrium thermochemical calculations predict that $HgCl_2$ will be formed at low temperatures in coal combustion flue gas, kinetic limitations mean that the equilibrium level of oxidation rarely occurs.[10] Scientists believe that the major kinetic pathway to the formation of mercuric chloride is through the reaction of atomic chlorine (Cl) and

---

[4]   Mercuric sulfide (HgS) and mercuric oxide are other forms of oxidized mercury that exist to a lesser degree in power plant flue gases.

[5]   *Merck Index, Tenth Edition*, entry no. 5710.

[6]   *Id.*, entry no. 5742.

[7]   *See, e.g.,* Electric Power Research Institute, *An Assessment of Mercury Emissions from US Coal-Fired Power Plants*, Report 1000608 (2000); Electric Power Research Institute, *Laboratory Investigation and Model Development of Flue Gas Mercury Adsorption Using Solid Sorbents,* EPRI Report TR-110533 (1998); Electric Power Research Institute, *Development and Evaluation of Low-Cost Mercury Sorbents*, EPRI Report 1000454, (2000).

[8]   C.L. Senior, "Behavior of Mercury in Air Pollution Control Devices on Coal-Fired Utility Boilers," p.2, *Presented at Power Production in the 21st Century: Impacts of Fuel Quality and Operations*, Engineering Foundation Conference, Snowbird, UT, Oct. 28-Nov. 2, 2001.

[9]   *Id.*

[10] *Id.*

elemental mercury.[11] Raw coal contains chlorine, just as it contains mercury, although the levels are highly variable. Following combustion, this chlorine is present in the flue gas and – under the right thermodynamic conditions – can react with mercury to form mercuric chloride. The available evidence suggests that where there is less than 100 ppm chlorine in the coal, little mercuric chloride will be formed in the flue gas; conversely, where there is greater than 500 ppm chlorine in the coal, mercuric chloride may be the predominant form of mercury in the flue gas.[12]

Importantly, however, the chlorine content of the coal is not the only factor that influences the generation of mercuric chloride in flue gas. At temperatures above 500^oF (260^oC), flue gas mercury tends to remain predominantly in the elemental form, even if ample chlorine is present to allow for formation of mercuric chloride.[13] Flue gas residence time may also be an important factor; a shorter residence time may mean higher flue gas temperatures but also means less time for the chlorine and mercury to react to form mercuric chloride. Conversely, a longer residence time allows additional time for this reaction to occur.

Other constituents of the flue gas may also influence the formation of mercuric chloride. Specifically, fly ash may catalyze oxidation of elemental mercury, and iron oxide may promote oxidation.[14] The presence of various other compounds, including unburned carbon and calcium compounds, hydrochloric acid, sulfur dioxide, nitrogen oxide and nitrogen dioxide in flue gas also appear to affect (directly or indirectly) the oxidation of mercury to mercuric chloride, in the presence of fly ash.[15] However, calcium in the fuel can also combine with chlorine, thus making the chlorine unavailable to oxidize mercury.

In sum, at flue gas temperatures below 500^oF, coal composition – including chlorine content, ash composition and the presence of some compounds such as iron oxide – is the dominant factor in determining the formation of mercuric chloride. At temperatures above 500^oF, mercury speciation is determined primarily by temperature, and elemental mercury is expected to be the dominant form.

As noted above, much less is known about particulate mercury. However, the fraction of mercury bound to particulates appears to be affected by the coal chlorine level and possibly the unburned carbon in fly ash. Specifically, the amount of particulate-bound mercury appears to increase with increasing chlorine content in the coal as well as with increasing amounts of unburned carbon in fly ash.[16] EPA has postulated that particulate-bound mercury is

---

[11]   *Id.* at 3.

[12]   *Id.* at 6.

[13]   *Id.*

[14]   *Id.* at 3.

[15]   *Id.*

[16]   Electric Power Research Institute, *An Assessment of Mercury Emissions from US Coal-Fired Power Plants*, Report 1000608 (2000); Electric Power Research Institute, *Laboratory Investigation and Model Development of Flue Gas Mercury Adsorption Using Solid Sorbents,* EPRI Report TR-110533 (1998); Electric Power Research Institute,

composed primary of oxidized mercury compounds (mercuric chloride and, to a lesser extent, mercuric sulfide and mercuric oxide), because the relatively high vapor pressure of elemental mercury makes it less likely that this compound would bind to particles.[17]

In sum, power plant flue gas contains three primary mercury-containing chemicals: elemental mercury, oxidized mercury (or mercuric chloride) and particulate-bound mercury. The coal composition and the final flue gas temperature are the primary determinants of which chemicals will be present – and in what amounts – in the flue gas of an individual power plant. As discussed further in Section IV below, the differing physical and chemical properties of these three mercury-containing compounds result in significant differences in the feasibility and effectiveness of controls for removing the compounds from flue gas.

III. LEGAL STANDARD FOR SUBCATEGORIZATION

A. Statutory Standard

Clean Air Act (CAA) § 112(c)(1) grants EPA broad discretion to establish "categories and subcategories" of sources to be regulated under Section 112. 42 U.S.C. §7412(c)(1). Section 112(d)(3)(A) provides that the MACT floor for existing sources shall be based on "the average emission limitation achieved by the best performing 12 percent of the existing sources . . . in the *category or subcategory*." 42 U.S.C. § 7412(d)(3) (emphasis added).[18]

The CAA further provides that EPA "may distinguish among *classes, types and sizes of sources* within a category or subcategory" when establishing MACT standards. CAA §112(d)(1); 42 U.S.C. § 7412(d)(1) (emphasis added). *Webster's Third New International Dictionary Unabridged* (1993) defines "class" to mean "a group, set or kind marked by common attributes or a common attribute." It defines "type" as "qualities common to a number of individuals that serve to distinguish them as an identifiable class or kind," further clarifying that "'Type', 'kind' and 'sort' are usually interchangeable" and that "'kind' in most uses is likely to be very indefinite and involve any criterion of classification whatsoever." Congress's use of the broad terms "type," "kind," and "size" shows that EPA is intended to have broad discretion in the appropriate factors that warrant distinguishing among sources for purposes of setting MACT floors and MACT standards.

Development and Evaluation of Low-Cost Mercury Sorbents, EPRI Report 1000454, (2000).

[17] EPA, *Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units--Final Report to Congress*, p. 7-7 (Feb. 1998).

[18] Importantly, there is no "absolute MACT floor" that exists outside of the context of categories and subcategories. Once a subcategory is created, the floor is set for the particular subcategory. The floor is *defined* by the best performing sources *within* the subcategory, not by the best performing sources outside of it. Therefore, setting MACT floors by subcategory, far from circumventing the intent of the Act, complies with the plain instructions of CAA § 112(d)(3). *See* 42 U.S.C. § 7412(d)(3).

B. Factors That Congress Intended EPA To Consider

The legislative history makes clear that Congress intended EPA to distinguish among classes, types and sizes of sources under three core circumstances: when differences among sources affect (1) the feasibility of air pollution control technology; (2) the effectiveness of air pollution control technology; and (3) the cost of control.

The Senate Report clarifies that the Administrator should:

> "take into account factors such as industrial or commercial category, facility size, type of process and other characteristics of sources which are likely to *affect the feasibility and effectiveness of air pollution control technology. Cost and feasibility are factors* which may be considered by the Administrator when establishing an emission limitation for a category under section 112. The proper definition of categories, in light of available pollution control technologies, will assure maximum protection of public health and the environment while minimizing costs imposed on the regulated community. However, in limited circumstances where a group of sources may share the characteristics of other sources in the category, the Administrator may establish subcategories for such sources."

S. Rep. No. 228, 101st Cong., 1st Sess 166 (emphasis added). Thus, in the view of the Senate, the standard for establishing categories and subcategories is essentially the same, although the Administrator is cautioned not to make too rampant use of subcategories.

Importantly, the report further provides that "Nothing in this language authorizes the establishment of a category based wholly on economic grounds, nor is there any implication that individual facilities may be granted *categorical* waivers (that is – separate categories will not be established for one or a few sources) from requirements that would apply to other sources of a similar size, type or character based on assertions of extraordinary economic effect." *Id.* (emphasis in original). In other words, the cost of control is an appropriate basis for distinguishing among sources *so long as* it is not the *only* basis that distinguishes among those sources; there must be some other difference, whether in "size, type or character," that distinguishes among the sources and results in a higher cost of control.

The House Report similarly provides: "EPA may distinguish among classes, types and sizes of sources within a category or subcategory. . . . In the determination of MACT for new and existing sources, consideration of cost should be based on an evaluation of the cost of various control options. The Committee expects MACT to meaningful, so that MACT will require substantial reductions in emissions from uncontrolled levels. However, *MACT is not intended to require unsafe control measures, or to drive sources to the brink of shutdown.*" House Rep. No. 101-490, Part 1, at 328 (emphasis added).

In sum, while Congress intended the MACT program to achieve significant emissions reductions, it also intended EPA to be cognizant of the costs of control, and to ensure that the program did not cause significant economic hardship. One primary mechanism for achieving this goal is through the use of subcategories; subcategorization enables the Agency to

account for the fact that distinctions among classes, types and sizes of sources may have a very real impact on the feasibility of a given control technology, the effectiveness of that control technology, and the cost of control.

C. Case Law

To date, none of the cases on Section 112 have addressed the scope of EPA's authority to establish subcategories for purposes of setting MACT standards. However, the language in Section 112 allowing the Administrator to "distinguish among classes, types and sizes of sources" when establishing MACT standards is identical to language in CAA Section 111, which similarly allows the Administrator to "distinguish among classes, types and sizes of sources" when establishing New Source Performance Standards (NSPS). *Compare* 42 U.S.C. § 7412(d)(1) *with* 42 U.S.C. § 7411(b)(2). The D.C. Circuit had occasion to consider this language in the context of the NSPS for power plants. *See Sierra Club v. Costle*, 657 F.2d 298 (D.C. Cir. 1981).

In that NSPS, EPA established a variable SO_2 reduction requirement, based on the SO_2 emission rate. Where the SO_2 emission rate was less than 0.60 lb/mmBtu, sources were required to meet only a 70% removal efficiency; sources that emitted at 1.2 lb/mmBtu, however, had to meet a 90% removal efficiency. In effect, then, sources that burned low sulfur coal were allowed to meet a less stringent removal efficiency (essentially allowing the use of spray dryers rather than FGD systems), while sources burning high sulfur coal were required to meet a more stringent removal efficiency. Significantly, a 90% removal efficiency was achievable for all sources, through installation of FGD technology.

Environmental groups challenged this standard, claiming that EPA could not, under CAA § 111, promulgate NSPS standards that varied depending on the amount of sulfur dioxide produced by the coal. *Sierra Club v. Costle*, 657 F.2d at 316. The D.C. Circuit held that CAA § 111 permitted EPA to promulgate emission standards that varied according to sulfur content. The Court noted that Section 111 expressly authorized EPA "to distinguish among classes, types and sizes within categories of new sources for the purpose of establishing . . . standards." *Id.* at 318; 42 U.S.C. § 7411(b)(2). The Court held that "on the basis of this language alone," it was reasonable for EPA to vary reduction standards by the amount of sulfur in the coal. *See Sierra Club*, 657 F.2d at 319. Rather than read the terms "classes, types and sizes" narrowly, so as to limit the grounds on which EPA might treat sources differently, the Court read the language as a broad grant of power to vary emission reduction standards on a variety of grounds. The Court stated, "[c]ertainly the text of the statute nowhere forbids a distinction based on sulfur." *See id.* at 319. Implicit in this statement is the Court's view that if CAA § 111 does not expressly prohibit varying emission standards on particular grounds, then EPA has the power to vary standards on those grounds: *e.g.*, fuel type (as in *Sierra Club*), process configuration or achievability.

Importantly, the *Sierra Club* Court recognized that Section 111 gives EPA sufficiently broad discretion to create different emissions standards for fuel types *even though* the strictest standard is *achievable* for all fuel types. In rejecting the environmental group's contention that CAA § 111 was "designed to permit a nonuniform standard only in the limited circumstance where a best technological system could not achieve the national percentage on

certain types of coal," the Court held "[t]he required finding that must underlie a variable standard is much broader than a mere determination that uniformity is not achievable." *See id.* at 321.

The Court's analysis in *Sierra Club* has obvious relevance to an analysis of the authority granted to EPA through CAA § 112. Section 112 employs the same language as Section 111 in defining when EPA may promulgate distinct emission standards. The Supreme Court has consistently held that "when administrative and judicial interpretations have settled the meaning of an existing statutory provision, repetition of the same language in a new statute indicates, as a general matter, the intent to incorporate its administrative and judicial interpretations as well." *Bragdon v. Abbott*, 524 U.S. 634, 645 (1998).[19] Therefore, Section 112, which adopted Section 111's terms almost *ten years* after the D.C. Circuit issued the *Sierra Club* decision, must be understood to carry the settled meaning given to those terms by *Sierra Club*. Section 112 provides, "[t]he Administrator may distinguish among *classes*, *types*, and *sizes* of sources within a category or subcategory in establishing such standards . . .". 42 U.S.C. § 7412(d)(1) (emphasis added). This authorization, when read in light of the controlling interpretation of *Sierra Club*, broadly licenses EPA to distinguish on the basis of any reasonable ground not expressly prohibited in the statute. The distinction need not be based on the physical structure of the source, but may also be based on the type of *fuel* processed in, the process configuration of, or the *pollutant* generated by the source.

Indeed, the Court's holding in *Sierra Club v. Costle* demonstrates that EPA has the authority to promulgate different standards for different fuel types, even where a uniform standard is achievable for those different fuel types, as long as it has reasons for the differential treatment. Since the Court found that lack of achievability is not necessary for justifying variable standards, it is clear that where differences among sources do affect achievability, achievability is a reasonable ground for differentiating among sources. *See Sierra Club*, 657 F.2d at 321 (holding that the variable standard at issue, although it did not vary by achievability, was reasonable and promulgated within the EPA's statutory authority because the EPA has "broad discretion to weigh different factors in setting the standard." The factors need not be limited to achievability). And while fuel type is an allowable method of differentiation among sources, it is not the only permissible approach. Other alternatives, such as process configuration or method of combustion, would be equally allowable under the Court's broad reading of the phrase "classes, types and sizes" of sources.

D.   EPA's Past Practice With Regard To Subcategorization

Both the text of CAA § 112 and the legislative history make it clear that EPA may tailor MACT standards to take into account pertinent differences among sources.

---

[19]   *See also North Star Steel Co. v. Thomas*, 515 U.S. 29, 34 (1995) (citations omitted) (holding that the Court expects Congress to be familiar with its precedents and anticipate that its enactments will be interpreted in conformity with those precedents); *Shapiro v. United States*, 335 U.S. 1, 16 (1948) (*quoting Hecht v. Malley*, 256 U.S. 144, 153 (1924)) (holding that "In adopting the language used in [an] earlier act, Congress must be considered to have adopted also the construction given by this Court to such language, and made it a part of the enactment.")

Subcategorization is the primary mechanism for tailoring standards, since it allows the grouping of facilities on the bases specified in the statute and according to the factors that Congress enunciated in the legislative history, including cost and feasibility and effectiveness of control technology. The statute uses the broad terms "class," "type" and "size" when identifying the bases on which EPA may distinguish among sources, evidencing – as the Court found in *Sierra Club v. Costle* – an intent to allow EPA to look broadly at the many factors that may affect the cost, feasibility and effectiveness of pollution control for different sources.

EPA's past practice has been consistent with this interpretation of the Act. The Agency has subcategorized sources in numerous industrial categories, including: leather finishing; ferroalloys; polymers and resins (I and IV); pharmaceutical manufacturing; publicly owned treatment works; printing and publishing; pulp and paper; steel pickling; phosphoric acid manufacturing and phosphate fertilizers production; hazardous waste combustors; halogenated solvent cleaning; secondary lead smelting; coke oven batteries; and metal can surface coating (within the context of a source (sub)category delisting petition).[20] EPA has proposed subcategories in a number of other MACT standards, such as: flexible polyurethane foam fabrication; reinforced plastic composites production; iron and steel manufacturing; coke ovens (pushing, quenching and battery stacks); rubber tire manufacturing; and secondary aluminum production.[21] In still others, EPA has declined to create subcategories but has discussed its rationale for that decision.[22]

---

[20] *See* 67 Fed. Reg. 9155 (Feb. 27, 2002) (leather finishing); 64 Fed. Reg. 27450 (May 20, 1999) (ferroalloys); 61 Fed. Reg. 46906 (Sep. 05, 1996) (polymers and resins); 61 Fed. Reg. 48208 (Sep. 12, 1996) (polymers and resins); 64 Fed. Reg. 57572 (Sep. 26 1999) (publicly owned treatment works); 61 Fed. Reg. 27132 (May 30, 1996) (printing and publishing); 63 Fed. Reg. 18504 (April 15, 1998) (pulp and paper); 62 Fed. Reg. 49052 (Sep. 18, 1997) (steel pickling); 64 Fed. Reg. 31358 (June 10, 1999) (phosphoric acid manufacturing and phosphate fertilizers production); 64 Fed. Reg. 52828 (September 30, 1999) (hazardous waste combustors); 58 Fed. Reg. 62566 (Nov. 29, 1993) (halogenated solvent cleaning); 60 Fed. Reg. 32587 (June 23, 1995) (secondary lead smelting); 64 Fed. Reg. 564393 (Oct. 20, 1999) (metal can surface coating); 58 Fed. Reg. 57898 (October 27, 1993) (coke oven batteries).

[21] *See* 66 Fed. Reg. 41718 (Aug. 8, 2001) (flexible polyurethane foam fabrication); 66 Fed. Reg. 40323 (Aug. 2, 2001) (reinforced plastic composites production); 66 Fed. Reg. 36836 (July 13, 2001) (iron and steel manufacturing); 66 Fed. Reg. 35326 (July 03, 2001) (coke ovens); 65 Fed. Reg. 62414 (Oct. 18, 2000) (rubber tire manufacturing); 64 Fed. Reg. 6946 (Feb. 11, 1999) (secondary aluminum production).

[22] *See, e.g.,* 64 Fed. Reg. 52828, 52859-860 (Sept. 30, 1999) (hazardous waste combustors – hazardous waste incinerators); 64 Fed. Reg. 52828, 52873-874 (Sept. 30, 1999) (hazardous waste combustors – cement kilns burning hazardous waste); 65 Fed. Reg. 76408, 76413, 76422 (December 6, 2000) (generic maximum achievable control technology – cyanide chemicals manufacturing, carbon black production; proposed amendments); 64 Fed. Reg. 31898, 31900 (June 14, 1999) (portland cement

From this past practice, it is possible to glean several principles that appear to govern the Agency's decision making with regard to creation of subcategories. First, EPA has determined that subcategorization is appropriate where sources use different processes, and those processes either: (1) result in different types or concentrations of uncontrolled HAPs; or (2) affect the applicability of control technology.[23] The Agency also has subcategorized sources based on size, where size differences affect the performance of control technologies, such as where more frequent start up and shut down makes it more difficult for smaller sources to maintain the same level of control as larger sources.[24]

Furthermore, the Agency has subcategorized sources where differences among sources affect the applicability of control technology. For example, EPA created subcategories in the 1999 polyether polyols production MACT standard, finding "Subcategorization was necessary due to the distinctively different nature of the epoxide and THF processes and its effect on the applicability of controls."[25] Similarly, in the 1998 flexible polyurethane foam production MACT standard, EPA found that "Subcategorization was necessary to reflect major variations in production methods, and/or HAP emissions that affect the applicability of controls."[26] Based on similar rationales, EPA created subcategories in the Group I polymers and resins MACT and the primary aluminum production MACT, and proposed to create subcategories in the polyurethane foam production MACT.[27]

---

manufacturing); 66 Fed. Reg. 58610, 58618-619 (November 21, 2001) (asphalt processing and asphalt roofing manufacturing).

[23] *See,e.g.,* 64 Fed. Reg. 27450 (May 20, 1999) (ferroalloys); 64 Fed. Reg. 57572 (Sep. 26 1999) (publicly owned treatment works); 61 Fed. Reg. 27132 (May 30, 1996) (printing and publishing).

[24] *See, e.g.,* 66 Fed. Reg. 40324, 40330-332 (Aug. 2, 2001) (reinforced plastics composites production - proposed); 58 Fed. Reg. 62566, 62568 (Nov. 29, 1993) (halogenated solvents cleaning, subcategorized based on size of cleaning machines); 59 Fed. Reg. 25004, 25013-14 (May 13, 1994) (marine tank vessel loading and unloading, subcategorized based on size).

[25] 64 Fed. Reg. 29240, 29434-436 (June 1, 1999).

[26] 61 Fed. Reg. 68406, 68407 (December 27, 1996), *finalized at* 63 Fed. Reg. 53980 (October 7, 1998).

[27] Group I polymers and resins: "Subcategorization was necessary to reflect major variations in production methods, raw material usage and/or HAP emissions that potentially affect the applicability of controls." 60 Fed. Reg. 30801, 30802 (June 12, 1995); Primary aluminum reduction plants (proposed): "For the subcategories of potliners, the distinctions are based primarily on differences in the process operation, process equipment, emissions, and the applicability of control devices." 61 Fed. Reg. 50586, 50588 (Sep. 26, 1996) ; Polyurethane foam production (proposed): subcategorization was appropriate because "Add-on controls are feasible for flame lamination, whereas loop slitter adhesive use emissions reductions have resulted from pollution-prevention measures such as changing the type of adhesive to a water-based or other non-HAP based material." 66 Fed. Reg. 41718, 41723 (Aug. 8, 2001).

Importantly, EPA also has created subcategories in numerous cases where differences among sources affected the *performance* of control technology and, hence, the achievability of the MACT standard. For example, in the steel pickling MACT, EPA excluded specialty steel because the technology that is effective for removing acid gas (HCl) emissions from carbon steel manufacturing "may not be as effective" for removing acid gas (H_2SO_4) emissions from specialty steel manufacturing.[28] Similarly, the phosphoric acid manufacturing MACT subcategorized the submerged combustion process and the vacuum evaporation process because the "submerged combustion process is not amenable to the same level of control as is the vacuum evaporation process."[29]

In the proposed leather finishing operations MACT, EPA "observed differences in achievable emission levels between the types of leather products produced . . . [and therefore] we have established four different performance standards for the various leather products produced."[30] The final leather finishing MACT standard created a subcategory that included "specialty leather finishing" in response to commenter's contentions that there was no suitable replacement for the solvents used in their operations, rendering the otherwise applicable MACT standard unachievable for these sources.[31] And in the proposed secondary aluminum production MACT, EPA "examined the processes, the process operations, and other factors to determine if separate classes of units, operations, or other criteria have an effect on air emissions from emission sources, *or the controllability of those emissions.*"[32]

Similarly, EPA has refused to create subcategories where the Agency concluded that differences among sources had no impact on the performance of control equipment and the achievability of the standard. For example, in the hazardous waste combustor MACT, EPA refused to create subcategories of cement kilns and incinerators, because the Agency concluded that for both, "the differences among [source] types 'does not affect the feasibility and effectiveness of air pollution control technology,'" and that the standards were achievable by all types and sizes of well-designed and operated sources using the MACT controls.[33] In its proposed amendments to the generic maximum achievable control technology standard, EPA refused to subcategorize carbon black production sources, finding that all carbon black sources have the "same . . . ability to control HAP emissions."[34]

Thus, in brief, EPA's past MACT standards have created subcategories where: (1) different types, classes or sizes of sources emit different types or concentrations of uncontrolled HAPs; (2) differences among types, classes or sizes of sources affect the applicability of control technology; and (3) differences among types, classes or sizes of sources affect the performance

---

[28]   64 Fed. Reg. 33202, 33207-208 (Jun. 22 1999).

[29]   64 Fed. Reg. 31358, 31360-362 (Jun. 10, 1999).

[30]   65 Fed. Reg. 58702, 58705-706 (Oct. 2, 2000).

[31]   67 Fed. Reg. 9155, 9158 (Feb. 27, 2002).

[32]   64 Fed. Reg. 6946, 6960 (Feb. 11, 1999) (emphasis added).

[33]   64 Fed. Reg. 52828, 52873-874 (Sep. 30, 1999).

[34]   65 Fed. Reg. 76408, 76422 (Dec. 6, 2000).

of control technology and, hence, the achievability of the standard. For the reasons discussed above, the Agency's past practice is consistent with the Act and its legislative history, and the applicable case law.

The Agency has stated its intention to follow a similar approach here. In its "Notice of Regulatory Finding on the Emissions of Hazardous Air Pollutants from Electric Utility Steam Generating Units," EPA stated:

> "[T]he EPA intends to develop a record to facilitate consideration of subcategorization of the source category in setting the 'floor.' Based on the information that EPA has to date, the EPA anticipates that a factual record will allow EPA to propose appropriate subcategories for this source category. In developing standards under section 112(d) to date, the EPA has based subcategorization on considerations such as: the size of the facility; the type of fuel used at the facility; and the plant type. The EPA may also consider other relevant factors such as geographic conditions in establishing subcategories."

65 Fed. Reg. 79825, 79830 (Dec. 20, 2000). The Agency's stated intentions are well within the scope of the law.

IV. POTENTIAL APPROACHES TO AND RATIONALE FOR SUBCATEGORIZATION OF POWER PLANTS

The following discussion identifies several possible approaches to subcategorization, and the rationale for why subcategorization on that basis would be appropriate for power plants. In brief, power plants could reasonably be subcategorized based on: (1) method of combustion (fluidized bed combustors versus traditional utility boilers); (2) coal rank, also properly identified as boiler design based on coal rank (boilers designed to burn eastern bituminous coal; boilers designed to burn western bituminous coals; boilers designed to burn subbituminous coals; boilers designed to burn Texas lignite coals; and boilers designed to burn North Dakota lignite coals); and (3) process configuration (plants whose configuration results in a hot stack (above the acid dew point); plants whose configuration results in a Saturated Stack (above the saturation temperature), and plants whose configuration results in a wet stack (saturated with water vapor)).

This approach to subcategorization would yield a total of between 8 and 16 subcategories (in a source category of close to 1,100 boilers), as follows:[35]

- Fluidized Bed Combustors; and

---

[35]   Further analysis of the entire ICR database may allow reductions in the number of subcategories. For example, it may be possible to combine some of the five categories of coal rank. Also, subcategorization based on process configuration may not be necessary for coal ranks where mercury speciation and removal are not shown to be sensitive to process variations.

Basis	Hot stack (above acid dew point)	Saturated Stack (above saturation temperature)	Wet stack (saturated with water vapor)
Eastern Bituminous coal	Eastern Bituminous/Hot Stack subcategory	Eastern Bituminous/Saturated Stack subcategory	Eastern Bituminous/Wet Stack subcategory
Western Bituminous coal	Western Bituminous/Hot Stack subcategory	Western Bituminous/Saturated Stack subcategory	Western Bituminous/Wet Stack subcategory
Subbituminous coal	Subbituminous/Hot Stack subcategory	Subbituminous/Saturated Stack subcategory	Subbituminous/Wet Stack subcategory
Texas Lignite[36]	Texas Lignite/Hot Stack subcategory	Texas Lignite/Saturated Stack subcategory	Texas Lignite/Wet Stack subcategory
North Dakota Lignite	North Dakota lignite/Hot Stack Subcategory	North Dakota lignite/Saturated Stack Subcategory	North Dakota lignite/Wet Stack Subcategory

Each of these possible bases for subcategorization is discussed further below.[37]

A. Method of Combustion – Fluidized Bed Combustors

In the pulverized coal furnaces that constitute the vast majority of power plant boilers, coal is pulverized in a mill to a fine consistency (approximately the consistency of talcum powder). That pulverized coal is entrained in air, then blown through burners to the furnace, where it is fired in the middle of the furnace.[38] This process results in widely dispersed fuel particles burning extremely quickly and at extremely high temperatures in suspended air. The residence time of the fuel particles is approximately the same as the residence time of the

---

[36] Texas lignite is also sometimes referred to as "Gulf Coast lignite." Similarly, North Dakota lignite is sometimes referred to as "Fort Union lignite."

[37] We do not have data on the differences between Texas and North Dakota lignites and their impact on plant design. We understand, however, that others are preparing information on this issue, which will be provided to the Agency at a later date.

[38] *See generally,* "Boiler Combustion Data: Bituminous and Subbituminous Coal Combustion," available at http://www.questargas.com/about_natural_gas/environmental_/boilercombcoal.htm.

flue gas, and temperatures at the burners reach in the range of 2500°F.[39] The burners are positioned in the lower to middle of the furnace (with the exact location determined based on the heat value of the coal being fired and the needed distance to the superheaters), with firing positions that may be on a single wall, opposing walls, vertical or tangential (*i.e.,* corner-fired). Some ash falls to the bottom of the furnace, in either a dry (dry-bottom) or a molten (wet-bottom) state, from which it is removed.[40]

Fluidized bed combustors utilize a fundamentally different approach to burning coal and, hence, producing electricity. Instead of introducing pulverized coal into the middle of the boiler, the fluidized bed process introduces relatively large coal particles (sometimes as large as 1.25 inches) to a bed of sorbent or inert material at the bottom of the boiler.[41] Sufficient air flow is introduced from the bottom of the boiler to result in the coal/sorbent (inert) mixture becoming fluidized. "Fluidization" refers to the condition in which solid materials are given free-flowing fluid-like behavior. As a gas is passed upward through a bed of solid particles, the flow of gas produces forces which tend to separate the particles from one another.[42] Thus, in fluidized bed combustion, coal is burned in a bed of hot incombustible particles suspended by an upward flow of fluidizing gas.

Solids in the fluidized bed are maintained at a temperature of 1500 to 1600°F. As the coal is introduced into the fluidized bed, it quickly heats to above its ignition temperature, ignites and becomes part of the burning mass that is the fluidized bed.[43] The larger fuel particles and lower temperatures in the fluidized bed result in a much longer fuel residence time. Basically, the fuel particles will remain burning in the fluidized bed until they are small enough either to be entrained by the combustion gas or removed with the bed drain solids.[44]

Thus, the fluidized bed combustor uses a fundamentally different process for burning fuel. That different process results in substantial differences in design, construction and operation of the unit. The following figures illustrate the differences in design between a fluidized bed combustion unit and a conventional unit.

---

[39]   S.C. Stultz and J.B. Kitto, *Steam: its generation and use, 40th Edition*, p. 16-3 (Babcock & Wilcox, 1992).

[40]   *See generally,* "Boiler Combustion Data: Bituminous and Subbituminous Coal Combustion," available at http://www.questargas.com/about_natural_gas/environmental_/boilercombcoal.htm

[41]   *Steam: its generation and use,* p. 16-3.

[42]   John Singer, P.E., *Combustion Fossil Power, A Reference Book on Fuel Burning and Steam Generation, 1991 Edition*, Ch. 9 (Combustion Engineering Inc. 1991).

[43]   *Id.*

[44]   *Steam: its generation and use,* p. 16-3.
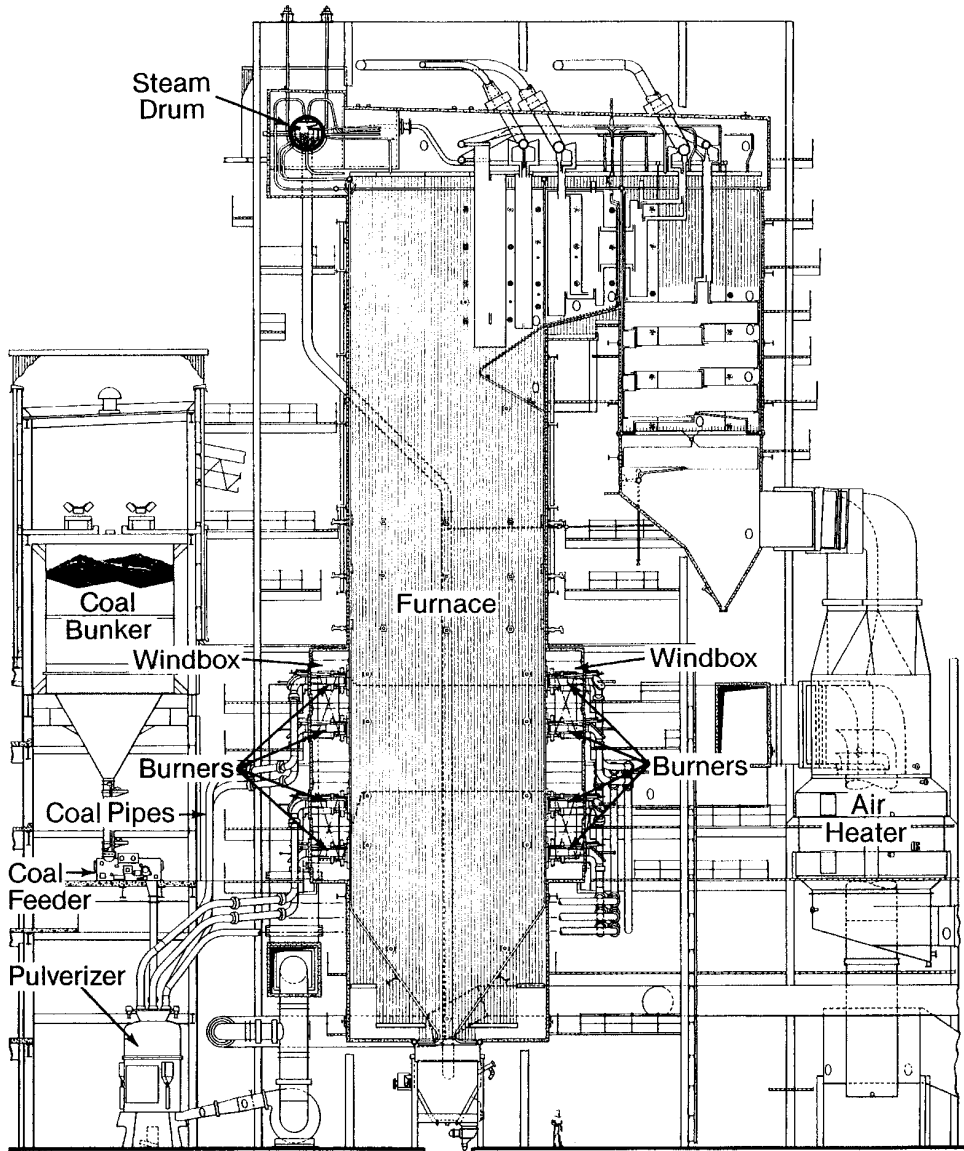
Fig. 3 Conventional pulverized coal-fired system.

Source: *Steam: its generation and use*, p. 13-3.
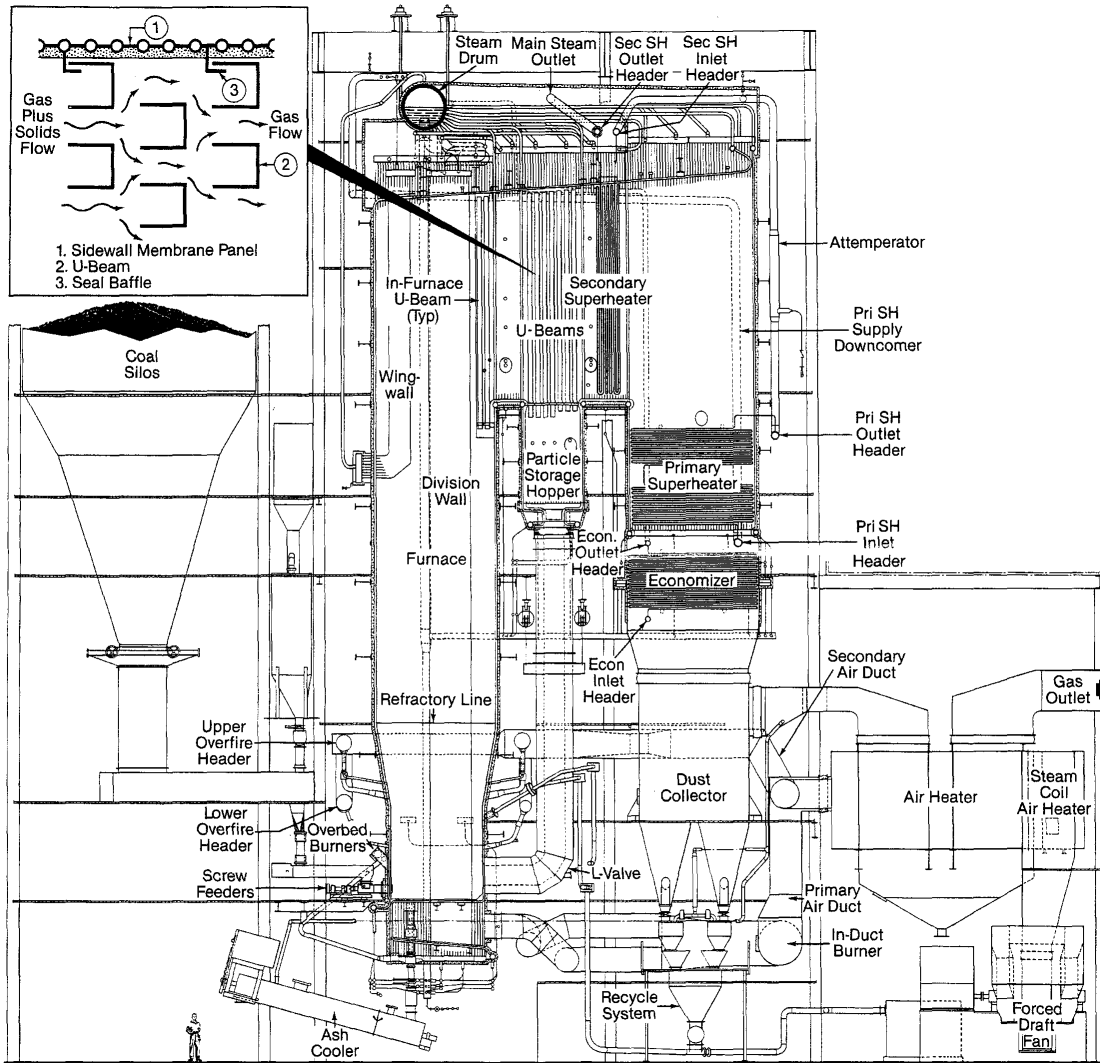
Fig. 15 CFB boiler sectional side view.

Source: *Steam: its generation and use*, p. 16-16.

In addition because it is a different process, fluidized bed combustion allows for different applications than a conventional boiler. The design and operating differences are such that a fluidized bed combustion unit can not be converted to operate like a conventional boiler unit and visa versa without essentially completely reconstructing the unit. The differences between the two types of plants are many and varied. Some of these differences are highlighted below:

- Conventional boilers simply mix fuel and atmospheric air. Fluidized bed combustion units are designed for combustion to take place in a fluidized bed of solids. This bed of solids typically contains materials for absorbing sulfur dioxide such as limestone, as well as ash from the combustion of coal.

15

- Fluidized bed combustion units combust larger particles of coal than conventional pulverized coal units. As a result they do not have the same coal pulverizing and crushing equipment as normal pulverized coal units.

- Because the combustion air has to lift and fluidize the solids bed, the fans that supply this air in a fluidized bed combustion unit must work against a larger pressure drop, and thus must be more powerful.

- In fluidized bed combustion units, the sulfur dioxide control is a part of the process itself. Lime or limestone is introduced into the bed of solids. The sulfur in the coal chemically reacts with the lime or limestone and is neutralized, thereby releasing very little sulfur dioxide.

- The combustion temperatures in a fluidized bed combustion unit are in the range of 1500-1650$^\text{o}$F. A conventional boiler operates closer to 2500$^\text{o}$F.

- In fluidized bed combustion, the resulting coal ash does not become molten as it does in a conventional boiler. As a result, ash handling systems are vastly different. In fluidized bed combustion, the solids are actually recirculated back into the unit for enhanced performance. In a conventional unit they pass immediately out of the unit.

- Fluidized bed combustion offers design versatility for burning a wide variety of fuels, including many that are too poor in quality for use in conventional firing systems.[45] The range of fuel choices are much more limited for conventional boilers.

- Because of lower combustion temperatures and gas velocities, the construction of a fluidized bed combustion unit is vastly different than a conventional unit. The fluidized bed combustion unit requires a different boiler tube design so that heat is properly absorbed to make steam of the correct properties. Similarly, the bottom of a fluidized bed boiler is utilized for air flow and combustion – both of which take place in the middle of a conventional boiler. The bottom of a conventional boiler is designed for ash drainage and removal.

Because of their fundamentally different design and operation, it would be appropriate to create a subcategory for fluidized bed combustors. As described above, there are numerous and fundamental differences between the processes used to produce steam (and hence, electricity) in a fluidized bed combustor as compared to a conventional boiler. A conventional boiler could not be converted to a fluidized bed combustor without essentially completely rebuilding the unit. Thus, fluidized bed combustors clearly constitute a different "class" or "type" of utility steam generating unit within the meaning of CAA § 112(d)(1).

The differences between fluidized bed combustors and conventional boilers also have significant implications for mercury removal efficiency. Based on the results from the ICR measurements, fluidized bed combustors were shown to achieve higher levels of mercury

---

[45]   *Combustion Fossil Power,* Ch. 9.

removals than for a traditional pulverized-coal-fired boiler.[46] The reasons for this improved removal efficiency are not readily apparent. For similar coals, however, fluidized bed combustors tend to have higher unburned carbon levels than conventional boilers.[47] The Electric Power Research Institute has theorized that these higher levels of unburned carbon in the fly ash yield a higher fraction of mercury capture by the fly ash – because, as discussed in Section II above, the presence of unburned carbon appears to facilitate the formation of particulate-bound mercury.[48] Particulate-bound mercury is readily captured by existing particulate control devices, including both fabric filters and electrostatic precipitators. In addition, the construction and operation of fluidized bed combustors allows for more intimate contact between the flue gas and solids, facilitating mercury removal.

Although the reasons are not well-understood, it is clear that fluidized bed combustors are capable of achieving a higher level of mercury reduction than are pulverized coal power plants – even when the same particulate controls are used. Whatever occurs within the fluidized bed combustor itself, however, clearly cannot be replicated in pulverized coal-fired boilers because of the fundamentally different technology that is used in the two types of units. Because the chemical reactions that occur within the fluidized bed combustor cannot be replicated in any conventional boiler without completely rebuilding that boiler, it is reasonable to conclude the control technology used in a fluidized bed combustor is *not applicable* to conventional boilers. At a minimum, however, the level of control that is *achievable* with fluidized bed combustors differs from what is achievable with conventional boilers.

Under such conditions, EPA's past practice has been to create separate subcategories.[49] The legislative history further suggests that subcategorization would be appropriate here, given the significant differences between these types of sources and their

---

[46]   Electric Power Research Institute, *An Assessment of Mercury Emissions from US Coal-Fired Power Plants*, Report 1000608 (2000).

[47]   Electric Power Research Institute, *TVA 160-MW AFBC Demonstration Project*, EPRI Report TR-100544-V2, (1994).

[48]   Electric Power Research Institute, *An Assessment of Mercury Emissions from US Coal-Fired Power Plants*, Report 1000608 (2000).

[49]   *See, e.g.,* 64 Fed. Reg. 29240, 29434-436 (June 1, 1999) (differences in control technology applicability – polyether polyols production); 63 Fed. Reg. 53980 (October 7, 1998) (differences in control technology applicability – flexible polyurethane foam production); 60 Fed. Reg. 30801, 30802 (June 12, 1995) (differences in control technology applicability – Group I polymers and resins); 64 Fed. Reg. 33202, 33207-208 (Jun. 22 1999) (differences in performance of control technology and achievability of standard – steel pickling); 64 Fed. Reg. 31358, 31360-362 (Jun. 10, 1999) (differences in performance of control technology and achievability of standard – phosphoric acid manufacturing);67 Fed. Reg. 9155, 9158 (Feb. 27, 2002) (differences in performance of control technology and achievability of standard – leather finishing).

impact on the applicability of control.[50] Accordingly, subcategorization of fluidized bed combustors is a reasonable and appropriate approach.

Finally, we note that based on a preliminary review of the data, it appears that commonalities in process may cause stoker boilers to most appropriately fit within the fluidized bed combustor subcategory. We are continuing to research this issue and will provide additional information to the Agency shortly.

B. Coal Rank

1. What Is Coal Rank?

The American Society for Testing and Materials (ASTM) classifies coals by "rank," a term which relates to the carbon content of the coal and other related parameters such as volatile-matter content, heating value, and agglomerating properties.[51] The heating value of coal is measured as the gross calorific value, reported in British thermal units per pound (Btu/lb). The heating value of coal increases with increasing coal rank.[52]

The youngest, or lowest rank, coals are termed lignite. Lignites have the lowest heating value of the coals typically used in power plants. Their moisture content can be as high as 30%, but their volatile content is also high; consequently, they ignite easily.[53] Next in rank are subbituminous coals, which also have a relatively high moisture content, typically ranging 15 to 30%. Subbituminous coals also are high in volatile matter content and ignite easily. Their heating value is in between that of the lignites and the bituminous coals.[54] Bituminous coals are next in rank, with higher heating values and lower moisture and volatile content than the subbituminous and lignite coals.[55] Anthracites are the highest rank coals. Because of the difficulty in igniting anthracite, only a single power plant boiler in the United States currently burns anthracite. The following table illustrates the different ranks of coals, as established by ASTM.

---

[50]   Alternatively, Congress has specified that the Agency should be cognizant of the costs of control. Obviously, requiring the entire utility fleet to rebuild into fluidized bed combustors to control mercury emissions would cause massive, widespread economic dislocation. Congress clearly intended the use of source categories and subcategories to avoid such a result.

[51]   T.C. Elliott, K. Chen, R.C. Swanekamp, *Standard Handbook of Powerplant Engineering*, p. 1.12 (McGraw-Hill 1998).

[52]   *Id.* at p. 1.18.

[53]   *Steam: its generation and use,* p. 8-6.

[54]   *Id.*

[55]   *Id.*

Table 1 Classification of Coals by Rank[56]

Class	Group	Fixed carbon limits, % (dry, mineral-matter-free-basis)		Volatile matter limits, % (dry, mineral-matter-free-basis)		Gross calorific value limits, Btu/lb (moist, mineral-matter-free basis)	
		Equal to or greater than	Less than	Greater than	Equal to or less than	Equal to or greater than	Less than*
1. Anthracite	1. Meta-anthracite	98	...	...	2	...	...[n]
	anthracite	92	98	2	...	...	...[n]
	2. Anthracite	86	92	8	14	...	...[n]
	3. Semianthracite						
2. Bituminous	1. Low volatile	78	86	14	22	...	...[c]
	2. Medium	69	78	22	31	...	...[c]
	volatile	...	69	31	...	14,000	...[c]
	3. High volatile A	...	...	...	...	13,000	14,000[c]
	4. High volatile B	...	...	...	...	11,500	13,000[c]
	5. High volatile C					10,500	11,500[a]
3. Subbituminous	1. Subbituminous A	...	...	...	...	10,500	11,500[n]
		...	...	...	...	9,500	10,500[n]
	2. Subbituminous B	...	...	...	...	8,300	9,500[n]
	2. Subbituminous C						
4. Lignitic	1. Lignite A	...	...	...	...	6,300	8,300[n]
	2. Lignite B	...	...	...	...	...	6,300[n]

Agglomerating character: n = nonagglomerating, c = commonly agglomerating, a = agglomerating.

Although rank can tell us much about the general characteristics of a given coal, it is important to recognize that coal properties vary widely between seams and within a given seam at different elevations and locations.[57] Indeed, coals can vary greatly from mine to mine within the same seam, and even within mines. For this reason, the analysis for a particular sample from a mine is said to be accurate only for the lot of coal that sample represents and can only generally represent the production from a particular mine.[58] The following table illustrates some of the differences between coals from different mines, even within the same ASTM rank classification.

---

[56]   *Standard Handbook of Powerplant Engineering*, p. 1.13.

[57]   *Steam: its generation and use,* p. 11-4.

[58]   *Standard Handbook of Powerplant Engineering*, p. 1.12.

Table 5
Seventeen Selected U.S. Coals Arranged in Order of ASTM Classification

	Coal Rank				Coal Analysis, Bed Moisture Basis						Rank	Rank
No.	Class	Group	State	County	M	VM	FC	A	S	Btu	FC	Btu
1	I	1	Pa.	Schuylkill	4.5	1.7	84.1	9.7	0.77	12,745	99.2	14,280
2	I	2	Pa.	Lackawanna	2.5	6.2	79.4	11.9	0.60	12,925	94.1	14,880
3	I	3	Va.	Montgomery	2.0	10.6	67.2	20.2	0.62	11,925	88.7	15,340
4	II	1	W.Va.	McDowell	1.0	16.6	77.3	5.1	0.74	14,715	82.8	15,600
5	II	1	Pa.	Cambria	1.3	17.5	70.9	10.3	1.68	13,800	81.3	15,595
6	II	2	Pa.	Somerset	1.5	20.8	67.5	10.2	1.68	13,720	77.5	15,485
7	II	2	Pa.	Indiana	1.5	23.4	64.9	10.2	2.20	13,800	74.5	15,580
8	II	3	Pa.	Westmoreland	1.5	30.7	56.6	11.2	1.82	13,325	65.8	15,230
9	II	3	Ky.	Pike	2.5	36.7	57.5	3.3	0.70	14,480	61.3	15,040
10	II	3	Ohio	Belmont	3.6	40.0	47.3	9.1	4.00	12,850	55.4	14,380
11	II	4	Ill.	Williamson	5.8	36.2	46.3	11.7	2.70	11,910	57.3	13,710
12	II	4	Utah	Emery	5.2	38.2	50.2	6.4	0.90	12,600	57.3	13,560
13	II	5	Ill.	Vermilion	12.2	38.8	40.0	9.0	3.20	11,340	51.8	12,630
14	III	1	Mont.	Musselshell	14.1	32.2	46.7	7.0	0.43	11,140	59.0	12,075
15	III	2	Wyo.	Sheridan	25.0	30.5	40.8	3.7	0.30	9,345	57.5	9,745
16	III	3	Wyo.	Campbell	31.0	31.4	32.8	4.8	0.55	8,320	51.5	8,790
17	IV	1	N.D.	Mercer	37.0	26.6	32.2	4.2	0.40	7,255	55.2	7,610

Notes: For definition of Rank Classification according to ASTM requirements, see Table 3.

Data on Coal (Bed Moisture Basis)

M   = equilibrium moisture, %; VM = volatile matter, %;   Rank FC = dry, mineral-matter-free fixed carbon, %;
FC   = fixed carbon, %; A = ash, %; S = sulfur, %;   Rank Btu = moist, mineral-matter-free Btu/lb.
Btu = Btu/lb, high heating value.   Calculations by Parr formulas.

Source: *Steam: its generation and use*, p. 8-6.

Two particularly important properties of coal, in terms of plant design and operation, are grindability and ash characteristics. The term "grindability" refers to the ease of pulverization of coal, and an index – the Hardgrove Grindability Index – has been developed to measure this property. Higher grindabilities indicate coals which are easier to pulverize. Hardgrove grindability varies as the moisture content changes, particularly for lignite coals and to a lesser extent for subbituminous coals. Studies of lignites at various moistures have shown a wide variation in grindability.[59] Coal pulverizing equipment is designed and specified at a particular plant for the grindability – and other characteristics – of the coals that particular plant is expected to burn.

"Ash composition," in turn, usually refers to the measurement of the following oxides of various elements in the ash: SiO_2, Al_2O_3, TiO_2, Fe_2O_3, CaO, MgO, Na_2O, K_2O, P_2O_5 and SO_3; knowledge of these parameters is important for determining slagging and fouling behavior in the boiler, as discussed further in Section IV.B.2, below.[60]

All coals contain some amount of ash. Ash content varies depending on the type of coal, location, depth of mine and even the mining method. Eastern bituminous coals generally

---

[59]   *Id.* at p. 2.101.

[60]   *Id.* at p. 1.18.

contain from 5 to 15% ash, while the western subbituminous coal ash content may range from 5 to 50% by weight. Texas lignites also contain up to 30% ash.[61] Importantly, however, the variation in ash content occurs not only in coals from different geographical areas or from different seams in the same region, but also from different parts of the same mine, primarily as a result of the wide range of conditions that could introduce foreign material during or following the formation of coal.[62]

The amounts of the individual ash elements also vary over a wide range for different coals. Nonetheless, there are characteristic differences between the high rank Eastern bituminous coals and the lower rank Western coals. For example, bituminous coals typically will have higher levels of silica, aluminum and iron; subbituminous and lignite coals generally have higher levels of calcium, magnesium and sodium.[63] Indeed, coal ash is classified into two categories based on its chemical composition: lignitic ash is defined as having more CaO and MgO (combined) than Fe_2O_3. Bituminous ash is defined as having more Fe_2O_3 than the sum of CaO and MgO.[64] Although (not surprisingly) bituminous ash is typical of the high rank Eastern coals and lignitic ash is typical of lower rank Western coals, in some unusual cases, lignites and subbituminous coals will have bituminous ash and bituminous coals will have lignitic ash.[65]

The following two tables illustrate some of the varying properties seen among U.S. coals.

---

[61]   *Steam: its generation and use,* p. 33-1.

[62]   *Id.* at p. 20-1.

[63]   *Id.* at p. 20-4.

[64]   *Id.* at p. 20-7.

[65]   *Id.* at p. 20-7.

Table 6
Properties of U.S. Coals

State	Anthracite	Pittsburgh #8 HV Bituminous	Illinois #6 HV Bituminous	Upper Freeport MV Bituminous	Spring Creek Subbituminous	Decker Subbituminous	Lignite	Lignite (S. Hallsville)	Lignite (Bryan)	Lignite (San Miguel)
	—	Ohio or Pa.	Illinois	Pennsylvania	Wyoming	Montana	North Dakota	Texas	Texas	Texas
Proximate:										
Moisture	7.7	5.2	17.6	2.2	24.1	23.4	33.3	37.7	34.1	14.2
Volatile matter, dry	6.4	40.2	44.2	28.1	43.1	40.8	43.6	45.2	31.5	21.2
Fixed carbon, dry	83.1	50.7	45.0	58.5	51.2	54.0	45.3	44.4	18.1	10.0
Ash, dry	10.5	9.1	10.8	13.4	5.7	5.2	11.1	10.4	50.4	68.8
Heating value, Btu/lb:										
As-received	11,890	12,540	10,300	12,970	9,190	9,540	7,090	7,080	3,930	2,740
Dry	12,880	13,230	12,500	13,260	12,110	12,450	10,630	11,360	5,960	3,200
MAF	14,390	14,550	14,010	15,320	12,840	13,130	11,960	12,680	12,020	10,260
Ultimate:										
Carbon	83.7	74.0	69.0	74.9	70.3	72.0	63.3	66.3	33.8	18.4
Hydrogen	1.9	5.1	4.9	4.7	5.0	5.0	4.5	4.9	3.3	2.3
Nitrogen	0.9	1.6	1.0	1.27	0.96	0.95	1.0	1.0	0.4	0.29
Sulfur	0.7	2.3	4.3	0.76	0.35	0.44	1.1	1.2	1.0	1.2
Ash	10.5	9.1	10.8	13.4	5.7	5.2	11.1	10.4	50.4	68.8
Oxygen	2.3	7.9	10.0	4.97	17.69	16.41	19.0	16.2	11.1	9.01

Ash fusion temps, F

Reducing/Oxidizing:	Red	Oxid	Red	Oxid	Red	Oxid	Red	Oxid	Red	Oxid	Red	Oxid	Red	Oxid	Red	Oxid	Red	Oxid	Red	Oxid
ID	—	—	2220	2560	1930	2140	2750+	2750+	2100	2180	2120	2420	2030	2160	2000	2210	2370	2470	2730	2750+
ST Sp.	—	—	2440	2640	2040	2330	"	"	2160	2300	2250	2470	2130	2190	2060	2250	2580	2670	2750+	"
ST Hsp.	—	—	2470	2650	2080	2400	"	"	2170	2320	2270	2490	2170	2220	2090	2280	2690	2760	"	"
FT 0.0625 in.	—	—	2570	2670	2420	2600	"	"	2190	2360	2310	2510	2210	2280	2220	2350	2900+	2900+	"	"
FT Flat	—	—	2750+	2750+	2490	2700	"	"	2370	2700	2380	2750+	2300	2300	2330	2400	2900+	2900+	"	"

Ash analysis:

SiO_2	51.0	50.58	41.68	59.60	32.61	23.77	29.80	23.32	62.4	66.85
Al_2O_3	34.0	24.62	20.0	27.42	13.38	15.79	10.0	13.0	21.5	23.62
Fe_2O_3	3.5	17.16	19.0	4.67	7.53	6.41	9.0	22.0	3.0	1.18
TiO_2	2.4	1.10	0.8	1.34	1.57	1.08	0.4	0.8	0.5	1.46
CaO	0.6	1.13	8.0	0.62	15.12	21.85	19.0	22.0	3.0	1.76
MgO	0.3	0.62	0.8	0.75	4.26	3.11	5.0	5.0	1.2	0.42
Na_2O	0.74	0.39	1.62	0.42	7.41	6.20	5.80	1.05	0.59	1.67
K_2O	2.65	1.99	1.63	2.47	0.87	0.57	0.49	0.27	0.92	1.57
P_2O_5	—	0.39	—	0.42	0.44	0.99	—	—	—	—
SO_3	1.38	1.11	4.41	0.99	14.56	18.85	20.85	9.08	3.50	1.32

Note: HV = high volatile; MV = medium volatile; ID = initial deformation temp; ST = softening temp; FT = fluid temp; Sp. = spherical; Hsp. = hemispherical.

Source: *Steam: its generation and use*, p. 8-9.

Ash Content and Ash Fusion Temperatures of Some U.S. Coals and Lignite

Rank	Low Value Bituminous	High Volatile Bituminous			Sub-bituminous	Li**gnite**	
Seam	Pocahontas No. 3	No. 9	No. 6	Pittsburgh		Antelope	
Location	West Virginia	Ohio	Illinois	West Virginia	Utah	Wyoming	Texas
Ash, dry basis, %	12.3 %	14.1	17.4	10.9	17.1	6.6	12.8
Sulfur, dry basis, %	0.7	3.3	4.2	3.5	0.8	0.4	1.1
Analysis of ash, %by wt							
SiO_2	60.0	47.3	47.5	37.6	61.1	28.6	41.8
Al_2O_3	30.0	23.0	17.9	20.1	21.6	11.7	13.6
TiO_2	1.6	1.0	0.8	0.8	1.1	0.9	1.5
Fe_2O_3	4.0	22.8	20.1	29.3	4.6	6.9	6.6
CaO	0.6	1.3	5.8	4.3	4.6	27.4	17.6
MgO	0.6	0.9	1.0	1.3	1.0	4.5	2.5
Na_2O	0.5	0.3	0.4	0.8	1.0	2.7	0.6
K_2O	1.5	2.0	1.8	1.6	1.2	0.5	0.1
SO_3	1.1	1.2	4.6	4.0	2.9	14.2	14.6
P_2O_5	0.1	0.2	0.1	0.2	0.4	2.3	0.1
Ash fusibility							
Initial deformation temp, F							
Reducing	2900+	2030	2000	2030	2180	2280	1975
Oxidizing	2900+	2420	2300	2265	2240	2275	2070
Softening temp, F							
Reducing		2450	2160	2175	2215	2290	2130
Oxidizing		2605	2430	2385	2300	2285	2190
Hemispherical, temp F							
Reducing		2480	2180	2225	2245	2295	2150
Oxidizing		2630	2450	2450	2325	2290	2210
Fluid temp, F							
Reducing		2620	2320	2370	2330	2315	2240
Oxidizing		2670	2610	2540	2410	2300	2290

Source: *Steam: its generation and use*, p. 20-6.

In sum, the properties of coal can vary widely from seam to seam, mine to mine and even within mines. Nonetheless, the ASTM method of classifying coals by "rank" generally is successful in identifying some core common characteristics that have implications for power plant design and operation. For example, lignites tend to have low heating value and high moisture, ash and volatile contents. Bituminous coals typically have lower ash, moisture and volatile content, and a higher heating value. Subbituminous coals range in the middle of the other two. As shown by EPA's ICR data, Western bituminous coals are typically lower in both mercury and chlorine content than Eastern bituminous coals.[66] In fact, they are closer in mercury and chlorine composition to the subbituminous coals from the same general area than they are to Eastern bituminous coals. In addition, the chemical composition of coal ash, while highly

---

[66]   For purposes of this discussion, Western bituminous coals are designated as those coming from the States of Arizona, Colorado, New Mexico, Utah and Wyoming.

variable, shows general trends based on coal rank. Specifically, bituminous coals tend to have ash with higher concentrations of silica, aluminum and iron, while subbituminous and lignite coals have ash with higher concentrations of calcium, magnesium and sodium. Thus, coal rank can be a useful tool for generally identifying some important characteristics of coals.

2. How Does Coal Rank Affect Plant Design?

The type of coal to be burned has an enormous impact on overall plant design. The goal of the plant designer is to arrange boiler components (furnace, superheater, reheater, boiler bank, economizer, and air heater) to provide the rated steam flow, maximize thermal efficiency and minimize cost. Engineering calculations are used to determine the optimum positioning and sizing of these components, which cool the flue gas and generate the superheated steam.[67] The accuracy of the parameters specified by the owner/operators is critical to designing and building an optimal plant.[68]

The three most important factors in modern boiler design are the steam conditions (the amount of steam required and the temperature and pressure of the primary and reheat steam), fuel and environmental constraints.[69] Indeed, there is little standardization of complete utility boiler designs because of the unique aspects of each user's requirements. Perhaps the most significant variation is differences in the types and range of fuels to be fired, which requires changes in the details and overall arrangement of boiler components.[70] As will be described further below, the type of coal to be fired has a significant impact on several areas of plant design. Fuel type is so important that plant designers and manufacturers expect to be provided with a complete list of all coal types presently available or planned for future use, along with their complete chemical and ash analyses so that the engineers can properly design and specify plant equipment.[71] For a boiler to operate efficiently, it is critical to recognize the differences in coals and make the necessary modifications to provide optimum conditions for efficient combustion.[72]

Pulverizers. The pulverizer is a component of the power plant with two functions. First, it grinds the coal to the proper fineness required for firing in the boiler. Second, it uses hot air to completely dry the coal particles prior to combustion. These two functions must be carried out in a controlled atmosphere so that the coal does not prematurely burn before it gets to the boiler, or cause a dust explosion.

The key difference between most of the rest of the boiler system and the pulverizer is that the pulverizer is sized and operated as a mass flow machine, while the boiler is

---

[67]   *Standard Handbook of Powerplant Engineering*, p. 2.44.

[68]   *Steam: its generation and use,* p. 24-1.

[69]   *Id.* at p. 24-2.

[70]   *Id.*

[71]   *Id.* at p. 24-2.

[72]   *Id.* at p. 12-8.

a thermal driven machine.[73] The heating value of the fuel thus becomes the core factor in integrating these two components.[74] Accordingly, pulverizers are designed and sized based on the type of coal that will be burned in the boiler.[75] That is, for the same size boiler (*i.e.,* in megawatts), a boiler that is designed to burn bituminous coal (with a relatively high heating value) will need pulverizer equipment that handles relatively less coal than pulverizer equipment for a boiler designed to burn subbituminous or lignite coals (which have relatively lower heating values).

In addition, however, the pulverizer design must consider the *fineness*, or required particle size, of the coal—an extremely important factor in system design. The desired fineness will depend primarily on coal characteristics and how they affect coal combustion in the furnace.[76] For example, when exposed to the high temperatures that are present in the furnace, caking coals will swell to form lightweight, porous coke particles that can easily float out of the furnace before they are burned.[77] There is a relationship between the rank of coal and the degree of fineness required for successful operation.[78] To ensure complete combustion within the furnace, and minimal carbon loss, high rank coals need to be pulverized to a finer size than coals of lower rank, as illustrated in the table below.[79]

Sizing Range of Coals for PC Firing[80]

Coal rank	Passing 200 mesh, wt %	Retained on 50 mesh, wt %
Subbituminous C coal and lignite	60-70	2.0
High-volatile bituminous C, subbituminous A, B	65-72	2.0
Low- and medium-volatile bituminous C, high-volatile bituminous A and B	70-75	2.0

In addition to fineness, pulverizer design must consider the *grindability* of the coal. As discussed in Section IV.B.1, above, this characteristic indicates the ease with which

---

73   *Id.* at p. 12-2.

74   *Id.*

75   *See, e.g., Steam: its generation and use,* p. 12-4, Table 1 (describing the operating characteristics of two types of pulverizers, based on a "bituminous coal with a 50 HGI [Hardgrove Grindability Index] and 70% fineness passing through 200 mesh.")

76   *Standard Handbook of Powerplant Engineering*, p. 2.104.

77   *Id.*

78   *Id.*

79   *Id.*

80   *Id.*

coal can be ground, and higher grindabilities indicate coals which are easier to pulverize.[81] Moisture content in the fuel can strongly influence grindability.[82] Coal moisture is highly variable, depending more on coal rank than on the amount of water introduced after mining. Appalachian bituminous coals have inherent moisture levels of approximately 2%, while moisture levels can reach close to 40% for lignites.[83] Additional moisture can be added through coal washing or from precipitation during transport. In addition to influencing grindability, the surface moisture and inherent moisture in the coal strongly influence the amount of drying needed. As a result, because more heat is required to dry wetter coals, moisture influences pulverizer air inlet temperature.[84]

Because direct-fired pulverizers are closely linked to the firing system, it is necessary to coordinate the design performance of the mills and the burners.[85] The coal and air feed rates need to be consistent with the estimated range of load demand under which the plant will operate.[86] Where the coal has low volatile content, higher air-coal temperatures may be required to assure stable combustion, especially at lower burner inputs or low furnace loads.[87] For example, one manufacturer's limitations for the maximum permissible pulverizer outlet temperatures, by coal rank, are set forth below. Importantly, exceeding the recommended temperatures may lead to lubrication problems in the grinding roller bearings, as well as increasing the risk of pulverizer fires.[88] Pulverizer fires are dangerous situations where the coal burns or explodes in the pulverizer or burner lines, presenting a significant safety hazard to the plant personnel and equipment.

Allowable Pulverizer Outlet Temperatures[89]

	Storage		Direct		Semidirect	
	F°	C°	F°	C°	°F	C°
High –rank, high-volatile bituminous	130*	54*	170	77	170	77
Low-rank, high-volatile bituminous	130*	54	160	71	160	71
High-rank, low-volatile bituminous	135*	57*	180	82	180	82
Lignite	110	43	110–140	43–60	120–140	49–60
Anthracite	200	93	?	?	?	?
Petroleum coke (delayed)	135	57	180–200	82–93	180–200	82-93
Petroleum coke (fluid)	200	93	200	93	200	93

*160 °F (71°C) permissible with inert atmosphere blanketing of storage bin and low-oxygen concentration conveying medium.

---

[81]   *Steam: its generation and use,* p. 12-8.

[82]   *Id.*

[83]   *Id.* at p. 12-10.

[84]   *Id.*

[85]   *Id.* at p. 12-6.

[86]   *Id.* at p. 13-5.

[87]   *Id.* at p. 12-8.

[88]   *Id.*

[89]   *Standard Handbook of Powerplant Engineering*, p. 2.110.

Finally, the type of coal to be burned also influences the choice of pulverizer, as illustrated below:

Types of Pulverizers for Various Coal Ranks[90]

Type of Material	Ball tube	Impact and attrition	Ball race	Ring roll
Low-volatile anthracite	X	—	—	—
High-volatile anthracite	X	—	X	—
Low-volatile bituminous coal	X	X	X	X
Medium-volatile bituminous coal	X	X	X	X
High-volatile A bituminous coal	X	X	X	X
High-volatile B bituminous coal	X	X	X	X
High-volatile C bituminous coal	X	—	X	X
Subbituminous A coal	X	—	X	X
Subbituminous B coal	X	—	X	X
Subbituminous C coal	—	—	X	X
Lignite	—	—	X	X
Lignite and coal char	X	—	X	X

As can be seen from the above discussion, the type of coal strongly influences pulverizer design. Indeed, pulverizer selection and sizing will be substantially complicated where the user wants to fire multiple coals.[91] If the coal that sets the pulverizer size is significantly different from the coal that will be the predominant fuel source, the plant may end up with oversized mills and limits on turndown on the primary coal.[92] Power plant design manuals recommend that where this is the case, the owner reconsider whether the coal that results in oversized mills should remain on the list of possible fuels.[93] At the other extreme, it is likely that changing coal types can result in a situation where there is insufficient capacity to process sufficient amounts of fuel to meet full load operation.

Boiler Size and Design. Coal rank similarly influences boiler size and design. Coal-fired boilers are designed to operate using fuel within a specified range of heating value and combustion characteristics.[94] Indeed, according to one boiler design manual, "The most fundamental factors that determine the boiler design are the steam production requirements and the coal to be fired."[95]

---

[90] *Id.* at p. 2.118.

[91] *Steam: its generation and use,* p. 12-10.

[92] *Id.*

[93] *Id.*

[94] *Standard Handbook of Powerplant Engineering*, pp. 1.14, 1.18.

[95] *Steam: its generation and use,* p. 13-3. *See also Standard Handbook of Powerplant Engineering*, p. 2.46) ("The type and quality of fuel to be burned, especially for coal, play a large part in the final boiler design.").

First, the ignition stability in the boiler varies directly with the ratio of volatile matter to fixed carbon.[96] Volatile matter is necessary to maintain flame stability and accelerate char burnout. Coals with minimal volatile matter are more difficult to ignite, requiring specially designed combustion systems.[97] Thus, anthracite fuels and low-volatile bituminous coals may require support ignition to enable them to burn in suspension. Alternatively, these fuels must be blended with a coal containing a higher percentage of volatile matter.[98] In contrast, coal with higher volatility can be more easily burned in suspension.[99]

Second, and more importantly, the characteristics of the ash at the various temperatures encountered in the furnace play a critical role in boiler design.[100] The sizing and configuration of the furnace must accommodate the combustion and slagging/fouling characteristics of the coal, which means that the type of coal burned determines the furnace size, among other things.[101] Sufficient furnace volume must be available to enable the fuel to burn with the minimum amount of slag formation and very little unburned carbon in the ash.[102]

The problem is basically this: because of the high temperatures that are present in the furnace, ash can be released in a molten fluid or sticky plastic state.[103] Any portion of the ash which is not cooled quickly to a dry, solid state will impact on and adhere to the furnace walls and other heating surfaces.[104] Recall that ash content averages between 5 and 50% of coal, by weight. Because of the large total quantities involved, when even a small fraction of the total ash adheres to the boiler, it can seriously interfere with plant operation.[105]

Indeed, ash deposit accumulations on furnace walls will impede heat transfer, thus delaying cooling of the flue gas and increasing the gas temperature leaving the furnace.[106] Elevated temperatures at the furnace exit in turn will raise the steam temperature too high, causing thermal degradation of the boiler and other components. Moreover, these elevated temperatures can result in ash deposition problems extending to pendant superheaters and other heat absorbing surfaces in the convection pass.[107] If a boiler combusts a fuel it is not properly configured to burn, uncontrolled ash deposits can develop that block flow passages in tube

---

[96] *Standard Handbook of Powerplant Engineering*, p. 2.46.

[97] *Steam: its generation and use,* p. 13-2.

[98] *Standard Handbook of Powerplant Engineering*, p. 2.46.

[99] *Id.*

[100] *Id.* at p. 1.18.

[101] *Steam: its generation and use,* p. 13-3.

[102] *Standard Handbook of Powerplant Engineering*, p. 2.46.

[103] *Steam: its generation and use,* p. 20-1.

[104] *Id.*

[105] *Id.*

[106] *Id.*

[107] *Id.*

banks, impeding gas flow and ultimately requiring unit shutdown. This can lead to the formation of extremely large slag deposits in the radiant superheater. When these deposits become dislodged, they fall great distances, causing extensive damage in the lower furnace and ash hopper.[108] Furthermore, some types of ash are very porous. As a result, when large, hot pieces of these ashes drop into water, water is drawn into them and turns to steam so quickly that they explode.[109] Specially designed systems are available to inhibit ash explosions by gradually immersing the ash in water.[110]

Because of its many potential deleterious effects, minimizing the potential for these ash-related problems is a primary goal of both the designers and operators of coal-fired boilers.[111] Thus, although the combustion characteristics of coal play a role in sizing the furnace, the deposition and erosion potential of the ash are the primary design considerations driving the overall size and arrangement.[112] Furthermore, because boiler systems are designed for specific fuels, they frequently will encounter combustion, slagging, fouling or ash handling problems if a fuel with characteristics other than those originally specified is fired.[113] Accordingly, design manuals specify that prior to boiler design and construction, "*All* potential boiler fuels must be assessed to determine the most demanding fuel."[114]

Some furnaces are designed to handle solid ash, while others are designed to handle molten ash at some degree of fluidity.[115] In the dry ash furnace, which is particularly applicable to coals with high ash fusion temperatures, a hopper bottom and sufficient cooling surface are provided so that the ash impinging on the furnace walls or the hopper bottom is solid and dry; it can be removed essentially as dry particles.[116] The chemistry of the ash therefore has a dramatic impact on the furnace volume necessary for satisfactory dry bottom unit operation.[117]

Bituminous, subbituminous and lignite coals require different boiler sizes primarily because of differences in the slagging potential of their ash. The furnace depth must be increased for subbituminous coals, and even more for lignites, to control slagging by reducing the input per plan area.[118] The input and gas weight also will be higher for the subbituminous

---

[108]   *Id.*

[109]   *Id.* at p. 23-8.

[110]   *Id.*

[111]   *Id.* at p. 20-1.

[112]   *Id.*

[113]   *Id.* at p. 18-4.

[114]   *Id.* (emphasis added).

[115]   *Standard Handbook of Powerplant Engineering*, p. 1.18.

[116]   *Steam: its generation and use,* p. 18-5.

[117]   *Id.*

[118]   *Id.* at p. 20-15.

coals and lignites due to their higher moister content, which results in lower boiler efficiency.[119] This in turn increases the required furnace surface and the furnace exit area in order to maintain acceptable gas velocities entering the convection pass.[120]
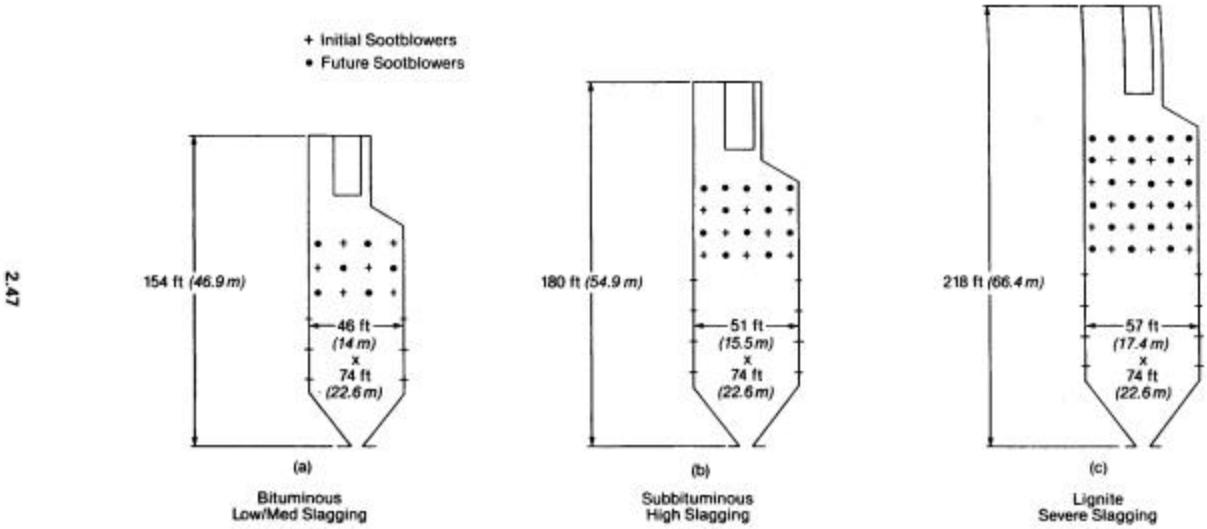

FIGURE 2.3.12 Influence of coal ash slagging potential on furnace size.

Source: *Standard Handbook of Powerplant Engineering*, p. 2.47.

Ash composition has other impacts as well. In designing boiler settings such as enclosures, casings and insulation, the effects of ash and slag must be considered. This is because destructive chemical reactions can occur between slag and metal or refractory under certain conditions. In addition, accumulation of ash on the waterwalls can significantly reduce heat adsorption. Moreover, ash accumulations can fall, causing injury to personnel or damage to the boiler, and high velocity ash particles can erode the pressure parts and refractory.[121]

The ash handling and transport systems also must be designed for the characteristics of each ash stream, including ash particle size, density and temperature, as well as the chemical composition and surface characteristics of the ash particles.[122]

Thus, ash characteristics are a critical parameter in the design of a power plant boiler. As discussed in Section IV.B.1, above, coal rank can reasonably be used to predict – with a fair degree of generality – the ash characteristics of a given coal. Nonetheless, the ultimate sizing and configuration of each individual boiler are designed to accommodate the ash and other characteristics of specific coals that are to be burned in that boiler. As discussed further in

---

119   *Id.*

120   *Id.*

121   *Id.* at 22-1.

122   *Id.* at p. 23-7.

30

Section IV.B.5, below, when new coals are introduced into the boiler, significant problems can arise.

          Convective Section Design. The boiler is basically a watertube-lined box which is designed to take advantage of the higher radiant heat flux near the burners.[123] The convective section of a boiler most often consists of large bundles of boiler tubing, through which the hot gas flows. The boiler tubing extracts heat from the partially cooled (to approximately 2000ºF) flue gas.[124] Here, the design goal is for the tube bundles to be as compact as possible without causing maintenance and operating problems. However, it is critical that the flue gas temperature at the entrance to the tube bundles in the convective section be below the ash-softening point to avoid excessive surface fouling.[125] The highly erosive nature of coal ash also requires that flue gas velocity be limited as it is carried through the convective section.[126] Limits typically range from 65 ft/s (129 m/s) for relatively nonabrasive, low ash coals to 45 ft/s (137 m/s) or less for abrasive, high-ash coals.[127] Adequate clearance between tubes also is required, particularly in zones of high gas temperature and when low rank fuels are burned.[128]

          Ash composition (and therefore slagging potential) also establishes the upper limit on furnace exit gas temperature (FEGT). These temperature limits are required to minimize the potential for slagging in the radiant superheater and the close-spaced convection surface.[129] In general, units using coals with low or medium slagging tendencies can have higher release rates and higher FEGTs. Units firing coals with high or severe slagging potential require lower heat release rates and lower FEGTs.[130]

          Soot blowers are necessary on coal-fired units to control ash deposits – but again, their design depends on coal characteristics.[131] Although slag and ash deposits on the furnace walls can be removed by short retracting IR wall blowers, the type of coal being fired determines the locations of the blowers.[132] For example, the vertical spacing of the rows of blowers would be between 10 and 14 feet with side to side spacing of 8 to 14 feet for a bituminous-type coal, but vertical spacing of the rows would be closer to 10 feet, and the side to side spacing 7 to 10 feet, for a severe slagging lignite.[133] Indeed, an entirely different "IK water lance sootblower

---

[123]   *Standard Handbook of Powerplant Engineering*, p. 2.45.

[124]   *Id.*

[125]   *Id.*

[126]   *Id.*

[127]   *Id.*

[128]   *Id.*

[129]   *Steam: its generation and use,* p. 20-14.

[130]   *Id.*

[131]   *Standard Handbook of Powerplant Engineering*, p. 2.45.

[132]   *Steam: its generation and use,* p. 23-4.

[133]   *Id.*

system" may be needed for some lignite and subbituminous coals with severe slagging or reflective ash deposits.[134]

Particulate Controls. Coal characteristics also influence the design of the plant's particulate control system. An electrostatic precipitator (ESP), for example, is designed to meet a specified particulate collection efficiency. Determining the appropriate ESP size and collection plate spacing depends upon the quantity of the particulate sent to the precipitator, particle size, particle composition and gas flow velocity.[135] As noted above, gas flow velocity is specified based in part on coal type and ash composition. In addition, certain fuel characteristics and ash constituents will change the electrical resistivity of an ash (and thus change its collectibility), for example moisture, sulfur, sodium, silica and potassium. Where the flue gas has sufficient quantities of these components, moderately-sized precipitators will usually suffice.[136] Calcium and magnesium, in contrast, will hamper ash collection and, if present in sufficient quantities and not offset by favorable components, will require larger precipitators because of poorer collection quality.[137]

In summary, the type of coal to be burned in the boiler has a major impact on steam generating equipment and plant design.[138] The properties of coal and its ash vary widely. As a result, power plant designers strongly recommend that *all* coals that may be burned in a boiler "should be tabulated to indicate chemical analyses, heating value and grindability . . . [with] each coal's ash analysis and ash temperature profile . . . listed."[139] Because of the fuel's marked impact on boiler design, "the analysis must be provided to the boiler supplier for proper selection of unit geometry, features and surfaces."[140]

In other words, while boiler design has certain core commonalities, *each individual boiler is designed to burn specific coals with specific characteristics.* If a company wants more fuel options, those characteristics have to be built into the initial design. However, that optionality also comes at a cost of other limitations. As discussed further in Section IV.B.5, below, where a company seeks to burn a new coal, with characteristics different from those for which the boiler was designed, either serious operational problems occur, or the plant must undergo significant modifications to enable it to burn the new fuel.

3. How Does Coal Rank Affect Mercury Speciation And Removal?

As discussed above, coal rank has significant implications for power plant design, such that plants designed to burn a specific type of coal cannot simply switch to another coal

---

[134]   *Id.*

[135]   *Id.* at pp. 33-3 – 33-4.

[136]   *Id.*

[137]   *Id.*

[138]   *Id.* at p. 37-2.

[139]   *Id.* at p. 24-3.

[140]   *Id.*

without substantial plant modifications or operational problems. In addition, however, coal rank has a significant influence on which mercury compounds are present in the flue gas – which in turn affects the ability of existing technologies to effectively remove the mercury from the flue gas.

The following table summarizes the differences in mercury content, chlorine content, and ash content – by coal rank (and other fuel type) and by State.[141] The State by State data demonstrate that there is wide variability in these parameters, even within coal ranks; however, the summary data for all locations demonstrates that some trends are clearly linked to fuel type.

Table 2-1. ICR State/Fuel Rank Analytical Summary

Fuel Source	Fuel Type	Mercury ppm	Chlorine ppm	Sulfur %	Ash %	Btu/lb*	No. of Samples
All Locations	Anthracite	0.165	309	0.58	32.1	9,366	156
All Locations	Bituminous	0.113	1,033	1.69	11.1	13,203	27,348
All Locations	Lignite	0.107	188	1.30	19.4	10,028	1,048
All Locations	Petroleum Coke	0.050	211	4.87	0.8	15,211	1,171
All Locations	Subbituminous	0.071	158	0.50	8.0	12,005	8,623
All Locations	Tires	0.056	1,065	1.56	7.5	15,170	149
All Locations	Waste Anthracite	0.189	249	0.53	48.6	6,898	334
All Locations	Waste Bituminous	0.462	848	2.41	37.5	8,753	575
All Locations	Waste Subbituminous	0.119	100	1.95	20.5	10,506	53
Alabama	Bituminous	0.117	247	1.10	13.8	13,262	684
Alaska	Subbituminous	0.071	100	0.22	14.8	10,069	35
Arizona	Bituminous	0.037	102	0.60	10.5	12,251	62
Aruba	Petroleum Coke	0.067	622	6.84	0.4	15,080	21
California	Bituminous	0.199	686	1.00	5.4	12,692	21
California	Petroleum Coke	0.046	203	0.97	0.7	14,990	113
California	Tires	0.200	529	1.38	4.4	8,500	2

---

[141] Source: Electric Power Research Institute, *An Assessment of Mercury Emissions from U.S. Coal-Fired Power Plants*, (September 2000).

Table 2-1. ICR State/Fuel Rank Analytical Summary (continued)

Fuel Source	Fuel Type	Mercury ppm	Chlorine ppm	Sulfur %	Ash %	Btu/lb*	No. of Samples
Colombia	Bituminous	0.100	235	0.75	6.5	13,479	88
Colorado	Bituminous	0.047	241	0.58	10.6	12,541	728
Colorado	Subbituminous	0.025	74	0.49	8.3	12,411	172
Illinois	Bituminous	0.083	2,011	2.46	9.7	13,076	2,106
Illinois	Petroleum Coke	0.024	277	3.74	0.5	15,394	79
Illinois	Subbituminous	0.025	51	0.28	5.9	12,137	3
Illinois	Tires	0.049	1,187	1.57	9.5	15,259	46
Illinois	Waste Bituminous	0.079	1,110	2.44	25.6	10,434	28
Indiana	Bituminous	0.077	375	2.20	10.6	12,966	1,411
Indiana	Petroleum Coke	0.089	212	4.86	0.3	15,531	284
Indonesia	Subbituminous	0.035	105	0.28	4.7	12,479	63
Kansas	Bituminous	0.084	1,535	3.80	16.3	12,470	124
Kansas	Petroleum Coke	0.040	281	3.65	0.3	15,490	34
Kentucky	Bituminous	0.095	1,086	1.44	10.7	13,216	5,336
Kentucky	Subbituminous	0.113	1,143	0.91	12.3	12,963	254
Kentucky	Waste Bituminous	0.102	745	1.90	12.8	12,673	76
Louisiana	Lignite	0.080	161	1.26	18.1	10,475	100
Maryland	Bituminous	0.180	686	1.64	15.8	13,187	213
Maryland	Waste Bituminous	0.342	753	3.89	30.2	10,593	51
Minnesota	Petroleum Coke	0.053	116	6.09	0.6	15,100	148
Missouri	Bituminous	0.100	391	4.10	19.2	11,841	30
Missouri	Tires	0.041	1,034	0.86	7.6	12,081	7
Montana	Lignite	0.097	200	0.80	12.2	10,702	41
Montana	Subbituminous	0.061	108	0.60	6.8	12,362	879
Montana	Waste Subbituminous	0.119	100	1.95	20.5	10,506	53
Nevada	Bituminous	0.057	1,642	0.79	27.3	8,646	3
Nevada	Subbituminous	0.047	168	0.69	26.7	8,606	3
Nevada	Waste Bituminous	0.053	1,584	0.78	28.8	8,933	3
New Mexico	Bituminous	0.068	48	0.77	17.0	11,975	32
New Mexico	Subbituminous	0.069	129	0.73	19.8	10,710	372
North Dakota	Lignite	0.087	133	1.19	13.5	10,573	383
Ohio	Bituminous	0.201	697	3.60	11.9	12,887	1,503
Oklahoma	Bituminous	0.279	1,171	3.55	13.8	12,896	92
Pennsylvania	Anthracite	0.165	320	0.55	33.2	9,164	147
Pennsylvania	Bituminous	0.193	1,050	1.88	10.6	13,635	3,067
Pennsylvania	Petroleum Coke	0.024	354	5.47	1.7	14,819	98
Pennsylvania	Waste Anthracite	0.190	254	0.53	48.2	6,959	321
Pennsylvania	Waste Bituminous	0.686	1,201	2.28	43.5	7,544	256
South American	Bituminous	0.061	257	0.79	7.6	13,594	50
Tennessee	Bituminous	0.097	859	1.15	11.5	13,302	107
Texas	Lignite	0.127	233	1.42	24.6	9,487	523
Texas	Petroleum Coke	0.035	125	6.12	0.6	15,262	90

34

Table 2-1. ICR State/Fuel Rank Analytical Summary (continued)

Fuel Source	Fuel Type	Mercury ppm	Chlorine ppm	Sulfur %	Ash %	Btu/lb*	No. of Samples
Unknown	Anthracite	0.160	137	1.06	14.1	12,666	9
Unknown	Bituminous	0.107	945	1.81	9.7	13,141	1,010
Unknown	Petroleum Coke	0.034	188	5.47	1.3	15,096	297
Unknown	Subbituminous	0.120	67	0.43	6.4	12,233	107
Unknown	Tires	0.056	1,023	1.62	6.6	15,506	93
Unknown	Waste Anthracite	0.178	118	0.40	58.7	5,389	13
Utah	Bituminous	0.052	205	0.55	10.1	12,762	649
Utah	Waste Bituminous	0.119	237	1.18	54.0	6,347	33
Various	Bituminous	0.084	2,730	1.22	8.3	13,426	1,202
Various	Subbituminous	0.136	279	0.71	8.0	12,163	140
Venezuela	Bituminous	0.067	398	0.74	5.6	14,014	18
Venezuela	Bituminous	0.081	373	0.76	6.8	13,719	63
Venezuela/ Colombia	Bituminous	0.114	329	0.71	7.7	13,922	9
Virginia	Bituminous	0.087	503	1.03	10.4	13,747	1,482
Washington	Subbituminous	0.067	104	1.21	20.4	10,438	90
West Virginia	Bituminous	0.113	1,023	1.54	12.7	13,152	7,138
West Virginia	Subbituminous	0.094	1,034	1.16	11.2	13,168	29
West Virginia	Waste Bituminous	0.458	324	2.74	41.9	8,358	128
Wyoming	Bituminous	0.036	144	0.66	7.0	12,563	113
Wyoming	Petroleum Coke	0.068	105	5.85	0.8	14,901	6
Wyoming	Subbituminous	0.070	127	0.44	7.2	12,000	6,476

* 10,000 Btu/lb = 21 J/kg

Thus, in general, bituminous coals tend to have higher chlorine content than subbituminous and lignite coals. The mean coal chloride for bituminous coal was 1033 ppm, compared with 158 and 188 for subbituminous and lignite coals. Lignite coals have higher ash content than bituminous or subbituminous coals. As discussed above, where there is less than 100 ppm chlorine in the coal, little mercuric chloride will be formed in the flue gas.[142] As a result, the flue gas from subbituminous and lignite coals – with their characteristic low chlorine contents – is expected to contain almost entirely elemental mercury.

Conversely, where there is greater than 500 ppm chlorine in the coal, oxidized mercury can be the predominant form of mercury in the flue gas – but may not be.[143] As discussed in Section II above, both flue gas residence time and final flue gas temperature also are important factors in determining whether elemental or ionic mercury will be the most prevalent form. At temperatures above 500°F (260°C), flue gas mercury tends to remain predominantly in

---

[142] C.L. Senior, "Behavior of Mercury in Air Pollution Control Devices on Coal-Fired Utility Boilers," p.6, *Presented at Power Production in the 21ˢᵗ Century: Impacts of Fuel Quality and Operations*, Engineering Foundation Conference, Snowbird, UT, Oct. 28-Nov. 2, 2001.

[143] *Id.* at 6.

the elemental form, even if ample chlorine is present to allow for formation of mercuric chloride.[144] Accordingly, for bituminous coals, the speciation of mercury may depend less on chlorine content (*i.e.,* coal rank) and more on process configuration, as discussed further below in Section IV.C.

Importantly, the effectiveness of air pollution control devices at removing mercury depends to a large extent on the type of mercury compound in the flue gas. In the ICR data, coal chloride content was a key factor in correlating both mercury speciation and removal. Increasing coal chloride levels yielded increasing levels of oxidized mercury – as well as mercury removal efficiency. It was concluded that oxidized mercury is more readily attached to ash particles than elemental mercury, making it easier to capture in particulate controls. Both electrostatic precipitators (ESPs) and fabric filters (FFs) are very good at removing particles. Hence, any mercury that is present in the particulate phase will be effectively removed by these control devices.[145]

Flue gas desulfurization devices (FGDs) can be moderately to very effective at removing oxidized mercury, but will remove essentially no elemental mercury.[146] Because both the mercury and SO_2 reactions are mass-transfer limited, the oxidized mercury removal efficiency in the FGD is comparable to the SO_2 removal efficiency. Consistent with this observation, where the coal has a high chlorine content, FGDs may remove about half of the gaseous mercury.[147] In boilers burning low chlorine content coals (such as low rank coals), the mercury is predominantly elemental and the FGD achieves little removal. Moreover, wet FGDs can capture oxidized mercury and re-release the mercury as elemental mercury, resulting in higher concentrations of elemental mercury at the outlet than at the inlet.[148]

In addition to removing particle-bound mercury, cold-side ESPs have some limited effectiveness at removing ionic mercury. However, they remove essentially no elemental mercury.[149] The following table summarizes the ICR test data for all cold-side ESPs.[150]

---

[144]   *Id.*

[145]   *Id.* at 3.

[146]   *Id.* at 9.

[147]   *Id.*

[148]   *Id.*

[149]   Electric Power Research Institute, *An Assessment of Mercury Emissions from U.S. Coal-Fired Power Plants*, p. 3-24 (September 2000).

[150]   *Id.* at 3-27 – 3-28..

Table 3-6. Cold-Side ESP Test Data Summary

Plant Name	Unit	MWe	Boiler Type	NOₓ Control	Coal Rank	Cl ppm	Cl/SO₂	Hg lb/TBtu	Hg Emissons, lb/TBtu			
									HgP	HgOx	HgE	Total
Bay Front Plant Generating (mechanical collector only)	5	32	Cyclone		Bit	127	124	4.73	0.05	1.64	1.3	2.99
Brayton Point	1	241	Tangential fired	LNB	Bit	575	513	5.83	0.55	2.39	0.34	3.28
Brayton Point	3	650	Tangential fired	LNB	Bit	966	846	5.86	0.42	2.16	0.6	3.18
George Neal south	4	639.9	Wall fired	OFA	Sub	57	79	7.52	0.025	3.25	4.55	7.83
Gibson Generating Station	3	668	Wall fired	LNB	Bit	2,100	766	11.07	0	6.06	3.49	9.56
Jack Watson	4	250	Wall fired	LNB	Bit	800	485	4.28	0.02	2.1	0.93	3.08
Leland Olds Station	2	440	Cyclone		Lig	115	59	5.04	0.003	0.78	1.73	2.513
Meramec	4	359	Wall fired	LNB	B/S	3,620	2,108	6.80	0	1.06	0.65	1.71
Montrose	1	170	Tangential fired	CC	Sub	133	346	9.60	0.0016	1.79	4.11	5.92
Newton	2	617.4	Tangential fired	LNB	Sub	76	110	6.38	0	1.4	5.5	6.9
Port Washington	4	80	Vertical fired		Bit	243	114	6.37	0.02	4.43	2.16	7.78
Presque Isle	6	90	Wall fired		Bit	197	121	3.06	0.03	0.62	0.59	1.23
Presque Isle	5	90	Wall fired		Bit	190	119	3.36	0.008	0.54	0.72	1.26
R.M. Heskett Station	B2	75	FBC		Lig	200	82	7.97	0.05	0.44	3.08	3.56
Salem Harbor	3	153	Wall fired	LNB & SNCR	Bit	264	253	2.00	0.06	0.1	0.27	0.43
St Clair Power Plant		168.75			S/B	250	165	4.86	0	0.97	2.85	3.82
Stanton Station	1	140	Wall fired	LNB	Lig	74	30	7.69	0.01	0.24	6.38	6.63

Table 3-6. Cold-Side ESP Test Data Summary (Continued)

Plant Name	Unit	MWe	Boiler Type	NOₓ Control	Coal Rank	Cl ppm	Cl/SO₂	Hg lb/TBtu	Hg Emissons, lb/TBtu			
									HgP	HgOx	HgE	Total
Widows Creek Fossil Plant	6	141	Wall fired		Bit	333	392	1.97	0.04	0.96	0.11	1.11
ESPc Outlet Data at Units with FGDw												
AES Cayuga (NY)	2	167	Tangential fired	LNB	Bit	882	246	7.36	0.0002	3.88	1.69	5.58
Bailly	7	194	Cyclone		Bit	517	15	3.86	0.04	1.78	1.66	3.47
Bailly	8	421.6	Cyclone		Bit	717	154	6.31	0.04	2.32	2.22	4.58
Big Bend	BB03	445.5	Wall fired	CC	Bit	1,750	360	10.68	0.04	3.45	1.68	5.17
Coal Creek	2	546.464	Tangential fired	LNB	Lig	18	10	9.67	0	2.09	5.75	7.84
Duck Creek	1	370	Wall fired	LNB	Bit	1,430	223	6.43	0.475	3.57	1.17	5.21
Jim Bridger	BW 73	560.6	Tangential fired	LNB & OFA	Sub	50	43	6.96	0.14	1.62	3.87	5.67
Limestone	LIM1	813	Tangential fired	OFA	Lig	365	129	14.06	0.01	11.6	6.3	17.9
Milton R. Young	B2	439	Cyclone		Lig	29	15	8.83	0	0.81	5.79	6.6
Monticello	3	793.25	Wall fired		Lig	133	92	48.48	0.1	14.92	20.37	35.41
Sam Seymour	3	475	Tangential fired		Sub	20	24	10.36	0.01	3.36	8.92	12.29

1 lb/TBtu = 0.48 ug/J

Because of the operating temperatures of a hot-side ESP, they will remove less ionic mercury than cold-side ESPs, and essentially no elemental mercury.[151] In addition,

---

[151]   *Id.* at 3-30.

however, the higher flue gas temperatures at the inlet to the device mean that with hot-side ESPs, less mercury has had an opportunity to convert to the ionic phase, where it is more capturable.[152]

Fabric filters also have some effectiveness at removing ionic mercury.[153] While the data suggest that these units may be able to remove elemental mercury as well, researchers believe a more probable explanation is that, with certain low chlorine content coals, the ash has sufficient unburned carbon to allow adsorption or solid catalyzed reactions to occur within the filter itself.[154] In the latter, mercury in the flue gas comes in intimate contact with ash particles and is converted to oxidized forms, making it more readily adsorbed onto the ash. As a result, researchers believe that actual removals for fabric filters may vary significantly from what would otherwise be predicted, based on ash characteristics that were not evaluated when EPA conducted its mercury study.[155]

Spray dryers, when used in combination with fabric filters, can be highly effective at removing ionic mercury.[156] The effectiveness of this technology combination correlates strongly with chlorine content of coal, with coals around 100 ppm chlorine or lower showing almost zero removal, and higher chlorine content coals showing excellent removal.[157] Thus, the data suggest that the spray dryer/fabric filter combination does *not* remove elemental mercury, although when sufficient chlorine is present in the flue gas, a portion of the mercury oxidation reaction may occur within the control device itself.[158]

Accordingly, coal rank is a useful indicator of certain key properties – such as coal chlorine content – which in turn impact the type of mercury compound that will be formed in the flue gas. The type of mercury compound in turn determines the effectiveness of air pollution control devices at removing mercury from the flue gas. Thus, coal rank impacts the effectiveness of mercury removal technologies.

---

[152]   C.L. Senior, "Behavior of Mercury in Air Pollution Control Devices on Coal-Fired Utility Boilers," p.6, *Presented at Power Production in the 21st Century: Impacts of Fuel Quality and Operations*, Engineering Foundation Conference, Snowbird, UT, Oct. 28-Nov. 2, 2001.

[153]   Electric Power Research Institute, *An Assessment of Mercury Emissions from U.S. Coal-Fired Power Plants*, p. 3-30 (September 2000).

[154]   *Id.*

[155]   *Id.*

[156]   *Id.* at 3-33.

[157]   *Id.*

[158]   *Id.* EPA also collected some data on removal efficiencies of spray dryer/ESP combinations. However, these data appear suspect so they are not discussed further here. *Id.*

4. Rationale for Subcategorizing Based On Coal Rank

As discussed above, the Act grants the Agency authority to "distinguish among classes, types and sizes of sources." 42 U.S.C. § 7412(d)(1). In interpreting an identical provision in Section 111 of the CAA, the D.C. Circuit expressly found that this language allowed the Agency to distinguish among sources based on fuel type – including distinguishing among different types of coal. *Sierra Club v. Costle*, 657 F.2d 298, 319 (D.C. Cir. 1981). This case demonstrates dispositively that EPA has the legal authority to subcategorize sources based on fuel type – including coal rank – for purposes of Section 112.

Indeed, EPA already has subcategorized power plants on the basis for fuel type: in its Section 112(n)(1)(A) determination, the Agency chose to regulate *only* coal- and oil-fired power plants under Section 112. EPA exempted gas-fired plants from regulation, thereby creating a clear subcategory based on fuel type.[159]

Even beyond that, however, it is clear that coal type has important implications for the overall design of the unit. While units will be designed for a specific range of fuels that are expected to be burned in the unit, coal rank provides a useful, broad indicator of required differences among units resulting from the burning of different coals. Thus, a unit designed to burn Virginia bituminous coal may not be able to readily burn, for example, an Illinois bituminous coal without significant consequences. But it certainly will not be able to burn a Wyoming subbituminous or Texas lignite coal – unless substantial modifications are made to the plant. In other words, plant design clearly varies within coal rank – but it varies even more among coal ranks. As a result, "coal rank" can be considered a shorthand for the many significant differences between plants with boilers and associated equipment designed to burn different ranks of coal. Coal rank therefore can properly be considered a different "class" or "type" of source – *i.e.,* plants that are designed to burn bituminous coal, plants that are designed to burn subbituminous coal, plants that are designed to burn lignite coal.

Having established that the Agency *can* distinguish among coal ranks as different "classes" or "types" of sources, the question then becomes whether EPA *should* do so. As discussed above, the properties of coal – particularly chlorine content, but also certain other parameters – have an important impact on the specific mercury-containing chemicals that exist in the flue gas. As discussed in Section II, above, there are three primary mercury-containing chemicals in flue gas, all of which have different physical and chemical properties: elemental mercury, mercuric chloride (and other minor species of oxidized mercury) and particulate-bound mercury. Coal rank is a reasonably accurate predictor of the chlorine content of coal, and low chlorine content is strongly associated with the presence of predominantly elemental mercury in the flue gas. In other words, coal rank can be used to predict which mercury-containing chemical will be predominantly present in the flue gas. In prior MACT standards, EPA has

---

[159]   65 Fed. Reg. 79825 (Dec. 20, 2000).

created separate subcategories where differences among sources resulted in different chemical emissions.[160] It would be appropriate to do so here as well.

Indeed, subcategorization based on coal rank is particularly appropriate because the specific mercury-containing compound strongly influences the *effectiveness* of existing control technologies at removing the mercury-containing compounds. For example, no in-place air pollution control devices currently are effective at removing mercury in the elemental form – such that the amount of elemental mercury in the flue gas strongly influences the removal efficiency at any plant – no matter what controls are in place.

In numerous past MACT standards, EPA has created subcategories where differences among sources affect the performance of control technology and, hence, the achievability of the MACT standard. For example, the steel pickling MACT excluded specialty steel, concluding that the applicable control technology "may not be as effective" for that type of source.[161] The phosphoric acid manufacturing MACT created subcategories because the "submerged combustion process is not amenable to the same level of control as is the vacuum evaporation process."[162] EPA used similar rationales for identifying subcategories in the leather finishing operations MACT[163] and the proposed secondary aluminum production MACT. [164]

EPA should adopt a similar approach here. Congress clearly contemplated that EPA would distinguish among source types where differences affected the "feasibility and effectiveness of air pollution control technology."[165] That is certainly the case here. Plants are designed to burn specific types of fuel – generally not even all fuels within a coal rank, but certainly not fuels in different coal ranks. And coal rank is a strong indicator of other fuel properties – such as chlorine content – that affect mercury removal efficiency and hence, the feasibility and achievability of the standard. Under such circumstances, subcategorization is appropriate.

Indeed, the Court in *Sierra Club* held that the Agency could distinguish among classes, types and sizes of sources *even if* the standard would be achievable for all sources. If it is reasonable to subcategorize when differences among sources do not affect achievability of the standard, certainly it is appropriate to subcategorize where differences *do* affect the achievability of the standard.

---

160   *See, e.g.,* 64 Fed. Reg. 27450 (May 20, 1999) (ferroalloys); 64 Fed. Reg. 57572 (Sep. 26 1999) (publicly owned treatment works); 61 Fed. Reg. 27132 (May 30, 1996) (printing and publishing).

161   64 Fed. Reg. 33202, 33207-208 (Jun. 22 1999).

162   64 Fed. Reg. 31358, 31360-362 (Jun. 10, 1999).

163   67 Fed. Reg. 9155 (Feb. 27, 2002).

164   64 Fed. Reg. 6946, 6960 (Feb. 11, 1999).

165   S. Rep. No. 228, 101st Cong., 1st Sess. 166. *See also* H.R. Rep. 101-490, Part 1 at 328 (1990).

5. A Comment About Coal Blending

Some have noted that to comply with the Acid Rain Program of the Clean Air Act Amendments of 1990, some Eastern plants burn subbituminous coal. As a preliminary matter, it is important to recognize that sources have done one of two things: (1) substantially modify their plants to enable them to burn subbituminous, rather than bituminous, coal; *or* (2) blend bituminous and subbituminous coals to achieve compliance with program requirements. Each of these is discussed in turn.

Coal Switching. As one power plant manual has written:

"In recent years, serious operating problems have arisen in boilers, large and small, when fuels have been changed to satisfy environmental requirements without due regard for basic boiler parameters. In many cases, such changes have led to reduced steam capacity, increased slagging, and poorer ignition stability."[166]

Another notes, in its chapter entitled "Life Extension and Upgrade": "If boiler and auxiliaries were designed solely for bituminous firing, switching to a subbituminous fuel could lead to reduced load, increased operating and maintenance expenses, and higher fouling and slagging in the furnace."[167] Simply the chapter in which this discussion is located indicates that significant changes to the plant are needed to accommodate the firing of a new type of coal.

For example, because subbituminous coals have lower heat rates, more fuel must be burned to achieve the same unit output. This in turn means that the capacities of coal conveyors, feeders, pulverizers, pulverizer dryers (because of increased moisture) and burners typically will need to be expanded, or the capacity of the plant decreased.[168] Changes in unloading, crushing, conveying, storage and pulverizing must also be made to account for the fact that subbituminous coal typically is more friable, increasing the risk of fires and explosions.[169] The increased fuel flow results in higher pipe velocities that in turn can cause increased erosion and flame instability.

Moreover, the increased fouling tendency of subbituminous coals means that sootblower and water washing protection may need to be added or expanded, along with potential air heater adjustments.[170] In addition, as discussed in Section IV.B.2, above, the ash characteristics of the fuel determine the size, location and spacing of pressure parts and combustion equipment. The ash characteristics of the new coal may not be compatible with

---

[166] *Standard Handbook of Powerplant Engineering*, p. 2.46.

[167] *Steam: its generation and use*.

[168] *Id.* at 46-11.

[169] *Id.*

[170] *Id.*

these configurations, making engineering studies and field tests a necessity before any fuel switch.[171]

Flues, ducts, fans, the electrostatic precipitator and the ash handling system may also need significant modification before any fuel switch can be made.[172] For example, changes in ash loading and resistivity, coupled with higher gas volume, may unacceptably reduce ESP performance.[173] In its "example case," one manual notes that trial burns of the subbituminous coal caused severe slagging in the furnace, pendant superheaters and tube sections, resulting in tube surface erosion causing extensive leaks that forced the unit to operate at reduced loads and contributed to reduced sootblower effectiveness.[174] Some boilers, because of their initial design specifications and choices, are more flexible to fuel blending or switching. However, fuel switching is not something that typically can be accomplished unless accompanied by extensive plant modifications.[175]

Coal Blending. Not surprisingly, many of the same problems seen with coal switching also can occur in a coal blending context. For example, coal blending may impact the pulverizer, combustion behavior and efficiency (including ignition, flame stability, reactivity and burnout characteristics), ash deposition behavior and the operation of PM controls.[176] Thus, blending coals – like switching coals – may necessitate changes in coal handling and preparation, as well as boiler adjustments or modifications to prevent fouling and slagging problems.[177]

Indeed, the complexities associated with coal blending are so significant that there has been extensive research to develop computer software and analytical methodologies for predicting the behavior of coal blends in individual boilers to avoid these operational issues.[178]

---

[171]   *Id.*

[172]   *Id.* at 46-12.

[173]   *Id.*

[174]   *Id.*

[175]   Coal switching can more easily occur within coal rank (although differences among coals may cause similar operational difficulties to those noted above). Many of the plants that "switched coals" to comply with the Acid Rain Program switched from high sulfur to low sulfur *bituminous* coals.

[176]   *See, e.g.,* A. Carpenter, *Coal Blending For Power Stations* (IEA, 1995); R.W. Bryers and N.S. Harding, *Coal-Blending & Switching of Lower Sulfur Western Coals*, (ASME 1994).

[177]   *See, e.g.,* R.W. Bryers and N.S. Harding, *Coal-Blending & Switching of Lower Sulfur Western Coals*, (ASME 1994).

[178]   *See, e.g.,* R. Sehgal and P.J. Marolda, *Intelligent Optimization of Coal Burning to Meet Demanding Power Loads, Emission Requirements and Cost Objectives*, (GE Power Systems 2000), available at http://www.gepower.com/publications/en_us/ pdf/ger4198.pdf; J.S. Shih and H.C. Frey, "Coal Blending Optimization Under Uncertainty," *Proceedings of the Tenth Annual Pittsburgh Coal Conference*, pp. 1110-1115 (1993); D. Matts, "Blending for Profit, Not Problems," presentation to be given at

Numerous documents, books, and presentations have been made on how to accomplish coal blending without impairing plant performance.[179]

For example, Han et al. (1999) reported on their experiences with coal blending to achieve reduced sulfur dioxide limits at a Korean plant for which space constraints precluded the installation of an FGD system.[180] Because of plant constraints, the blended coal had to have the following properties: combustibility index above 3,500; unburned carbon below 4.5%; slagging index below 0.5; fouling index below 0.2; heating index above 5,800 kcal/kg; moisture below 16%; and Hardgrove Grindability Index above 45. In addition, the sulfur content of the blend could not exceed 0.32%, so that the new emissions limits could be achieved.[181] Use of subbituminous coal alone far exceeded the plant's design specifications, requiring the use of blending. The plant evaluated over 40 different coals, ultimately identifying 6 subbituminous and 12 bituminous coals that, if blended properly, could meet the required plant and environmental specifications.[182]

Although the identified blends were within the range of specifications, the plant nonetheless encountered some significant operational difficulties when it attempted to switch to a blended fuel. First, the pulverizer inlet temperature needed to be raised to properly dry and grind the coal – but initially, this caused a fire in the pulverizer.[183] The plant also needed to increase pulverizer power due to the decrease in grindability of the blend, again increasing the risk of fire

---

2002 Electric Power Expo, St. Louis, MO (March 19-21, 2002); Thermo Electron Corporation, "Online Coal Analysis," *World Coal* (December 2001); United Kingdom Department of Trade and Industry, "Enhancing Handleability Through Coal Blending Using Multi-Parameter Optimization," (Cleaner Coal Technology Programme Project No. 257, 1999); D.R. Dugwell, R. Kandiyoti, A.J. Guell and D. Peralta, "Fundamentals of coal blend combustion behavior," available at http://www.ce.ic.ac.uk/common-room/files/drd_3.pdf.

[179] *See, e.g.,* A. Carpenter, *Coal Blending For Power Stations* (IEA, 1995); R.W. Bryers and N.S. Harding, *Coal-Blending & Switching of Lower Sulfur Western Coals*, (ASME 1994); R. Sehgal and P.J. Marolda, *Intelligent Optimization of Coal Burning to Meet Demanding Power Loads, Emission Requirements and Cost Objectives*, (GE Power Systems 2000), available at http://www.gepower.com/publications/en_us/pdf/ger4198.pdf; J.S. Shih and H.C. Frey, "Coal Blending Optimization Under Uncertainty," *Proceedings of the Tenth Annual Pittsburgh Coal Conference*, pp. 1110-1115 (1993); D. Matts, "Blending for Profit, Not Problems," presentation to be given at *2002 Electric Power Expo*, St. Louis, MO (March 19-21, 2002).

[180] J.K. Han, H.K. Hong, S.K. Lee, and Y.Z. Kim, "A Coal Blending Experience for the Reduction of Power Plant SO_2 Emissions," available at http://www.netl.doe.gov/publications/proceedings/99/korea99/yzkim.pdf (1999).

[181] *Id.* at pp. 3-4.

[182] *Id.* at p. 5.

[183] *Id.* at p. 6.

or explosion at the bottom of the pulverizer.[184] The higher volatile content of the coal also caused firing in the vicinity of the coal burner nozzle and overheating on the water wall tubes of the burner area. Increased slagging and fouling also resulted in overheating on the water wall tubes, and the increases in airflow caused superheater steam temperatures to fall. Power consumption of fans was increased, as was dry gas loss, and overall boiler efficiency decreased. At the same time, the increase in unburned carbon and electric resistance of ash caused a decrease in the performance of the electrostatic precipitator.[185] Significant changes were needed to address these issues and enable the safe and effective use of blended coal.[186] Similar experiences have been reported by others.[187]

In sum, coal blending is not necessarily a simply undertaking. Where the coal to be blended has properties that differ from the coals for which the plant was designed, blending can cause significant operational problems. Indeed, some coals may be unacceptable for use at a particular plant, while others may be limited in the degree to which they can be used. Coal blending may also require some substantial operational changes at the plant. Thus, the degree to which coal blending can occur at an individual plant is limited by the plant design – and particularly, the coals which the plant was designed to burn and the compatibility of the blended coal's properties with the original design parameters.

C.   Process Configuration

1.   What Is Process Configuration?

Process configuration refers to how a generating unit is designed and constructed. In particular, it refers to what post-boiler equipment is installed on the plant, and the sequence in which it is installed. The type of equipment selected and its sequence in turn determine whether the flue gas temperature exiting the last process component will be hot (above the acid dew point), saturated (just above the saturation temperature) or wet (saturated with water vapor). The temperature from the final control device temperature in the majority of cases will be about the same temperature as the flue gas exiting the unit's stack.

---

[184]   *Id.*

[185]   *Id.*

[186]   *Id.* at pp. 7-12.

[187]   *See, e.g.,* Z. Wu, *Prevention of Particulate Emissions*, (IEA Center for Applied Energy Research, 2000), abstract available at http://www.caer.uky.edu/iea/ieaccc40.htm; J. Sulpizio, "Annual Project Report of the Lorain Port Authority," (1985), available at http://www.odod/state.oh.us/tech/coal/pdf/684200.pdf; A. Carpenter, *Coal Blending For Power Stations* (IEA, 1995); R.W. Bryers and N.S. Harding, *Coal-Blending & Switching of Lower Sulfur Western Coals*, (ASME 1994); D. Matts, "Blending for Profit, Not Problems," presentation to be given at *2002 Electric Power Expo*, St. Louis, MO (March 19-21, 2002); D.R. Dugwell, R. Kandiyoti, A.J. Guell and D. Peralta, "Fundamentals of coal blend combustion behavior," available at http://www.ce.ic.ac.uk/common-room/files/drd_3.pdf.

Process configuration choices are made at during the original design and construction of the unit. At this time, the designer selects the type of process equipment and its order of arrangement. The size of the components and materials of construction are specified according to the anticipated requirements. Changing from one process configuration is not a trivial effort. Rather, such changes require large-scale and expensive revamping of the plant.

Coal-fired units are designed and constructed with different process configurations because of the site-specific requirements or constraints placed on the initial design of the unit. These constraints included the properties of the fuel to be used, emissions limitations and applicability of control technology for pollutants such as SO_2, particulates and NO_x. The fuel constraints include not only the coal rank (bituminous, subbituminous, or lignite), but also more specific properties of the particular coal(s) to be consumed by the unit. These fuel properties include, but are not limited to, the amount of sulfur and moisture, and the amount and chemical composition of the ash. Major power plant components such as boilers, particulate controls, etc. are specified based on particular coal properties.

Accordingly, these site-specific constraints dictate the process equipment selected, the component order, the materials of construction and the operating conditions. Units are configured for different reasons, but the most important are the selection of emissions controls equipment, and the need to maximize unit efficiency by recovering waste heat from the flue gases prior to release.

EPA has found in its review of ICR data that the capture of mercury by flue gas cleaning devices is dependent upon mercury speciation. Both elemental and oxidized mercury are in the vapor phase at the temperature of flue gas cleaning devices. Elemental mercury is insoluble in water and cannot be captured by wet scrubbers. However, the most common oxidized mercury compounds in coal flue gas are weakly to strongly soluble and the more soluble can be captured in wet FGD systems.[188]

Existing units and their emission controls were not constructed with the specific purpose of removing mercury, although those controls do produce some "co-benefit" removal of mercury. Data collected as part of EPA's Mercury ICR have shown that process configuration significantly impacts the speciation of mercury emissions, and hence the magnitude of reductions achievable from a generating unit. The degree of mercury speciation (and removability) varies with the different type of process used, primarily because mercury speciation changes due to factors such as flue gas chemistry. As discussed above, mercury speciation and removability also varies within a given process depending upon the rank of coal used.

Hot Stack Process Configuration. In a hot stack process configuration, the stack exit temperature is above the acid dew point. "Acid dew point" refers to the temperature where sulfuric acid begins to condense from a vapor to a liquid in the flue gas. In a hot stack process, the flue gas temperature is kept high enough to prevent acid condensation and the subsequent corrosion it causes. This protects a large portion of the plant components, such as air heaters, ductwork, particulate control devices, fans and stacks.

---

[188]   EPA, *Control of Mercury Emissions from Coal-Fired Electric Utility Boilers: Interim Report*, p. ES-6 (Dec. 2001).

Any coal burned by a generating unit will contain some amount of sulfur. When the fuel is combusted in a pulverized coal or cyclone boiler, that sulfur is largely converted to SO_2. A small fraction (on the order of about 1%) is further oxidized to sulfur trioxide (SO_3). For a flue gas with 1,000 to 2,000 ppm of SO_2, this would result in a SO_3 concentration of between 10 ppm and 20 ppm. The amount of oxidation can vary and depends upon many factors, such as fuel type, the types of equipment installed, residence time and the amount of excess air. The conversion rate is not necessarily consistent even between similar boilers combusting the same fuel. As shown by recent experience, for example, adding Selective Catalytic Reduction (SCR) to a generating unit for NO_x control will increase the amount of SO_2 that oxidizes to SO_3. Once sulfur trioxide is formed, some will combine with the fly ash and be captured by electrostatic precipitators, or absorbed with the fly ash in fabric filter.[189]

Sulfur trioxide is very hydroscopic. As the flue gas cools to below about 400°F, the sulfur trioxide begins to absorb moisture from the flue gas. The water chemically combines with the SO_3 to form sulfuric acid (H_2SO_4) at a very rapid rate.[190] This acid will be in a vapor state with a vapor pressure proportional to the amount of acid in the flue gas. As the flue gas cools, it will reach the saturation temperature for that concentration (vapor pressure) of sulfuric acid in the flue gas. The point where the sulfuric acid vapor begins to condense into an aerosol is called the acid dew point.

The acid dew point occurs at a temperature of about 250°F to over 300°F, depending upon the initial sulfur content of the coal and the fraction of SO_2 that oxidized to SO_3.[191] The higher the initial concentration of SO_3, the higher the acid dew point. In a stream of flue gas, it is not uncommon for the temperature to vary +/-25°F across the unit. Because of this variation, it is important to keep all of the gas above the acid dew point, not just the average. Otherwise, localized areas of acid condensation will occur.

Once the acid condenses, it can collect upon the internal components of a generating unit, usually in a cold spot. In liquid form, the acid is very corrosive. As a result, acid dew point is critically important to boiler designers and operators because operating below the acid dew point will cause significant corrosive damage to components and structures.

Thus, for subcategorization purposes, Hot Stack units should be defined as units with a stack temperature of greater than 275°F. "Hot Stack" units typically have the following process configuration:

- Boiler

- Air Heater

---

[189]   Note: a full discussion of this topic is beyond the scope of this paper. For more information, *see* K. Harrison and L. Monroe, "Estimating Total Sulfuric Acid Emissions from Coal Fired Power Plants – Revised", p. 7 (September 1998).

[190]   *Id.* at p. 9.

[191]   *Steam, Its Generation and Use*, p. 19-11.

- Particulate Control Device (precipitator, fabric filter, etc.)

- Induced Draft Fans

- Stack

The foregoing is the most common configuration and includes units with a cold side ESP and fabric filters. Hot stack units also include ones where the order of the air heater and precipitator used for particulate control are reversed – a configuration most commonly referred to as a "Hot Side ESP." While the order of these two components is reversed, the unit still was built with the same objective of keeping the flue gas hot enough to prevent acid condensation and attendant corrosion problems. In the ICR database, some units are recorded as having very high outlet temperatures, some in excess of 400°F. In these cases, the temperatures were measured after the "last pollution control device," which in this case was the Hot ESP. However, it should be remembered that for these facilities, the air heater is downstream of the Hot ESP and the final stack temperature will be considerably lower.

Boilers utilize air heaters to capture waste heat from the flue gas and use it to preheat the combustion air. The three most common types of air heaters are Ljungström, Rothemühle, and tubular.[192] These air heaters are designed to recover as much heat as possible, while still staying above the acid dew point.

The final exit temperature of the air heaters is controlled by the size and construction of the air heaters. In some cases, air heaters are constructed with dampers to bypass a portion of the flue gas and/or the combustion air around the air heater. This reduces the amount of heat removed from the flue gas, thus keeping the temperature sufficiently high.

Air heater manufacturers specify a minimum final gas outlet temperature to prevent corrosion. As one boiler manufacturer states,

> "The economic and practical limits to improved boiler efficiency by lowering the unit's exit gas temperature, have essentially been reached. Corrosion and/or plugging of air heaters and dust collection equipment generally determine the lower temperature limit, which depends largely on the sulfur content of the fuel being burned. Efforts to design and operate modern units for sustained periods with 250°F final flue gas temperature at full load generally have been unsuccessful with many fuels and usually the design objective is *at least 25°F higher or 275°F*."[193]

---

[192]   *Id.* at p. 19-8

[193]   John Singer, P.E., *Combustion Fossil Power, A Reference Book on Fuel Burning and Steam Generation, 1991 Edition*, p. 6-6 (Combustion Engineering Inc. 1991) (emphasis added).

Different methods are used to specify the final temperature limits of the air heater. For example, one manufacturer uses an Average Cold End Temperature (ACET), which is the average of the final air heater gas outlet, and the air inlet temperature.[194] Other manufacturers specify a Minimum Metal Temperature for the air heater components.[195] When following these limits, the plant operator has to also consider that by their design, Ljungström and Rothemühle air heaters will have a degree of leakage of the colder combustion air into the flue gas. This dilutes the combustion gas and reduces the temperature closer to the acid dew point. The leakage is localized to specific portions of the air heaters. While plant operators can reduce the amount of leakage, the inherent design of the device is such that it cannot be completely eliminated. As a result, operators have to raise the gas outlet temperature to compensate for this leakage. Flue gas is also cooled by leakage of outside air through dampers, fan shafts and other equipment. This also results in localized cooling of the flue gas and cold spots. At these cold spots, acid will condense and cause corrosion.

Because the flue gas temperature in Hot Stack units is kept relatively high, the acid carried in the flue gas is not corrosive to the air heaters and the other downstream components. As a result, these components are not constructed of corrosion resistant materials. Regular carbon steels, for example, are used in the ductwork and for precipitator components. If the temperature is reduced below the acid dew point, however, corrosion can – for example – attack the unit's electrostatic precipitator and impede its ability to collect fly ash. Decreased precipitator performance, in turn, can lead to exceedences of particulate and opacity limits. Concerns with acid dew point extend beyond particulate controls. Corrosion also can damage fans and stacks, undermining the integrity of these devices, as well potentially causing structural failure.

Plant operators do, however, have an incentive to operate their units with flue gas temperatures as close to the acid dew point as possible. By doing so, they recapture as much waste heat as possible and thus improve their energy efficiency. For a coal-fired unit, a 40°F increase in flue gas temperature represents about a 1% reduction in total unit efficiency.[196] However, as previously stated, plant operators have essentially reached their efficiency limits. In addition, while there are processes, such as humidification, that can be used to reduce flue gas temperature, these processes would reduce the flue gas temperature below the acid dew point – but would *not* remove the acid – resulting in acid corrosion and attendant damage to the plant.

Saturated Stack. In a Saturated Stack, the flue gas exits the stack at a temperature below the acid dew point, although the gas remains above the water saturation temperature. Saturated stack units remove much of the sulfur oxides (SO_2 and SO_3) from the flue gas. As a result, they avoid the corrosion associated with operating below the acid dew point. In most cases, saturated stack units have a dry scrubber or spray dryer installed to remove sulfur dioxide. Because the spray dryer introduces a large amount of solids into the flue gas, it must be located ahead of the particulate control device.

---

[194]   *Id.*

[195]   *Steam, Its Generation and Uses*, p. 19-11.

[196]   *Id.* at p. 44-4.

48

Saturated stack units have the following process configuration:

- Boiler

- Air Heater

- Sulfur Dioxide Control

- Particulate Control Device (precipitator, fabric filter, etc.)

- Induced Draft Fans

Dry scrubbing (or a spray dryer) is the principle alternative to wet scrubbing (FGD systems) for SO_2 control. It involves spraying a highly atomized slurry or aqueous solution of an alkaline reagent into the hot flue gas to absorb the SO_2. Unlike a wet scrubber installation, the dry scrubber is positioned before the particulate control device. Flue gases leave the air heater in the range of 250°F to 350°F and enter the dry scrubber through a mixing device such as an array of Turbo-Diffusers®. The quantity of water in the atomized spray is limited so that it completely evaporates in suspension. SO_2 absorption takes place primarily while the spray is evaporating. The spray also adiabatically cools the flue gas. The difference between the temperature of the gas leaving the dry scrubber and the adiabatic saturation temperature is known as the approach temperature. Reagent stoichiometry and approach temperature are the two primary variables, which dictate the spray dryer's SO_2 removal efficiency.[197]

Spray dryers are lower in capital cost as compared to wet FGD systems. However, they achieve a lesser SO_2 removal efficiency and therefore are limited to use with lower sulfur fuels A spray dryer will consume more reagent for the same amount of sulfur reduction, but use of a fabric filter can obtain some additional removal by filtering the flue gas through the particulate layer of the bag surface.

As a result, dry scrubbing in the United States has been applied mainly to units burning low sulfur fuels. Of the U.S. utility dry scrubber installations, the majority are located west of the Mississippi River.[198] Data from EPA's Mercury Information Collection Request (ICR) do indeed show that of the 13 units with spray dryers selected for Part III testing, 9 of them were located west of the Mississippi. Of the spray dryers stack tested as part of the ICR, only 3 used coal with sulfur content above 1.1% during the test. Of these three, only one was larger than 70 MW, and it burned lignite coal.

The temperature of the flue gas leaving the dry scrubber must be high enough to ensure proper operation of the particulate control device. The particulate control device can be either an ESP or a fabric filter. The ESP is more forgiving of temperature variation, but a fabric filter provides better reaction of SO_2 with lime.[199] In either case, the ash, unreacted lime or

---

[197]   *Steam, Its Generation and Uses*, p. 35-12.

[198]   *Id.* at p. 35-11.

[199]   *Steam, Its Generation and Uses*, p. 35-12.

absorbed sulfur oxides must remain dry and in a powered or granular form. If this material is allowed to become wet, it will form a sludge cakes that "blinds" the fabric of a fabric filter, and/or causes deposition and pluggage in both a fabric filter and an ESP.

In addition to spray dryers, a small portion of saturated stack units utilizes a dry sorbent injection either alone or with some form of humidification. Because they also remove a portion of the acid mists that cause dew point corrosion, these units also would be considered saturated stack units.

The units with a saturated stack configuration are significantly different in their process design and construction, as compared to hot stack units. There are several reasons for these differences. First, saturated stack units must have the facilities to receive and process the materials required to prepare a slurry of chemical reagent and water. That slurry must then be injected into the flue gas and intimately mixed. Second, there must be sufficient residence time to allow for complete evaporation of the water contained in the slurry. Third, because the flue gas contains not only the fly ash, but the lime or other reagent used to remove the sulfur oxides, the particulate control device must be designed for a much higher particulate loading. The particulate controls of a hot stack unit would not be sufficient for a unit to install a spray dryer without reconstruction. Indeed, compared to a hot stack unit, the flue gas in a saturated stack unit has a higher weight (the addition of evaporated water vapor), different gas density (due to lower temperatures and more water vapor) and undergoes additional pressure drop (from gas mixing equipment in the spray dryer and particulate controls). As a result, the fans and their associated equipment are substantially different in a saturated stack unit.

Wet Stack. In a Wet Stack configuration, flue gas will exit the stack at the water saturation temperature. The wet stack configuration is typified by units with wet FGD systems, venturie scrubbers or particulate scrubbers. These control devices are saturated with water vapor, and spray a mixture of lime and water into the flue gas for SO_2 control. Units with a saturated stack configuration have the following process configuration:

- Boiler

- Air Heater

- Particulate Control Device (precipitator, fabric filter, etc.)

- Induced Draft Fans

- Sulfur Dioxide Control

Because the flue gas is substantially below the acid dew point before sulfur oxides are removed, these units commonly use higher alloy steels and other materials to prevent corrosion in the scrubber vessel and downstream components. In addition, the flue gas in the scrubber and downstream of the scrubber is highly saturated with moisture. The moisture droplets collect sulfur oxides and other chemicals from the flue gas and tend to be very acidic. A wet stack therefore must be constructed very differently from a hot stack. Where a hot stack achieves its corrosion resistance by using a higher flue gas temperature, a wet stack must use

corrosion resistant materials, such as acid resistant brick. It should also be noted that some units have stack temperatures that are higher than the absorber module outlet temperatures. This is because some units bypass a small amount of heat to increase plume buoyancy.

Since a wet stack configuration will in most cases will have particulate controls as well as sulfur controls, the two will in tandem reduce mercury emissions.[200] Because it is insoluble in water, however, wet FGD systems do not remove elemental mercury. Oxidized mercury compounds are soluble in water and alkaline scrubbing solutions, making wet FGD systems moderately to very effective at removing this species of mercury. Therefore, the overall mercury removal efficiency is a function of the fraction of mercury that enters the scrubber in the oxidized form.

Multiple locations have reported that in some instances a wet FGD system will reduce a portion of the oxidized mercury back into its elemental form. The mercury is then outgased from the slurry and is emitted from the stack. This appears to be particularly true with bituminous coals. The end result is that for these situations, while a scrubber will reduce the concentration of oxidized mercury, the concentration of elemental mercury may increase.[201]

NO$_x$ Controls. The first method for reducing emissions for Nitrogen Oxides (NO$_x$) occurs within the boiler itself. Low NO$_x$ Burners (LNBs) are the most common NO$_x$ control device and they are installed on a large percentage of generating units. In addition, some units utilize Selective Non-Catalytic Reduction (SNCR). SNCR works by spraying a reagent, most commonly urea, into the furnace where it reacts with and reduces NO$_x$ to water and molecular nitrogen. An SNCR operates between 1600°F and 2100°F.[202] At this temperature, mercury is believed to remain in the elemental form and SNCR or LNBs are not believed to have an appreciable effect on mercury speciation or removal.

The units tested as part of the ICR included Salem Harbor, which operated with an SNCR. That particular unit did achieve high levels of mercury reduction. However, there is no evidence that the SNCR itself improved mercury capture and removal. Rather, for that particular unit, there were additional factors that may have contributed to mercury removal. For example, the unit operated with a very high level of unburned carbon and is thought to have an unusually high flue gas residence time within the unit. Both factors could have increased mercury reduction independent of the SNCR. This past summer, an additional unit operating with an SNCR was tested under a program sponsored by EPRI, EERC and others. This testing

---

[200]   The exception to this rule is a small number of cases where wet particulate scrubbers are used without any upstream particulate controls. These plants also are considered part of the wet stack process configuration.

[201]   M.G. Milobowski, "Wet FGD Enhanced Mercury Control for Coal Fired Utility Boilers," (March 2002).

[202]   V. Ciarlante, "Design and Characterization of a Urea-Based SNCR System for a Utility Boiler," p. 3, *presented at* EPRI/DOE/EPA Utility Air Pollution Control Symposium (August 25-29, 1997).

could not find any change in mercury speciation or capture resulting from the operation of an SNCR.[203]

For the reduction of NO_x to significantly lower levels, an SCR is often employed. Because the reaction generally is most effective at temperatures above 600°F, the catalyst bed must be installed upstream of the air heaters to allow the reaction to occur. There is evidence that in some selected applications, the catalytic action of an SCR may aid in the oxidation of elemental mercury. Worked performed by the Electric Power Research Institute (EPRI) and the Energy and Environmental Research Center (EERC), sponsored in part by EPA and DOE, has tested multiple sites with operating SCRs. This testing, along with earlier pilot level testing, has demonstrated that this oxidation reaction does occur, although it appears to be site-specific and greatly influenced by factors such as the specific coal used by the unit. The effects of SCR on mercury speciation are in their early phases of understanding, but for some coals with sufficient chlorine content, an SCR may promote oxidation of mercury from the elemental form. It is not known if this will happen with a relatively new catalyst or if the reaction will continue through the entire catalyst life. But if SCR is successful at further oxidizing mercury from the elemental form, then removal efficiencies should be improved.

It is anticipated that SCRs will most likely be added between the boiler outlet and existing air heaters. In the case of units with hot side ESPs, they can be added immediately down stream of the ESP. While inserting this device into the existing process flow is challenging, it by itself does not require the reconfiguration or order of the devices, nor does it require the reconstruction of the existing components. (The exception would be cases where the facility must upgrade to more powerful Induced Draft Fans.) As a result, the three process configurations described above remain robust enough to include the addition of an SCR without necessitating any additional categories.

Changing Process Configurations. The previously described process configurations were constructed using a set of assumptions. There are significant differences between the configurations in terms of equipment and materials of construction, representing a large fraction of the total cost of the generating unit. While it is physically possible to reconfigure a unit from one process configuration to another, doing so will typically require extensive reconfiguration of the existing equipment or, in many cases, outright replacement of that equipment.

For example, if a unit currently has only particulate control devices, the addition of a spray dryer will require not only the addition of the spray dryer vessel itself, but also a complete retrofit of the particulate control device to withstand the higher particulate loadings. Moreover, as noted above, spray dryers should not be used with higher sulfur fuels because they simply cannot spray enough liquor into the flue gas to achieve the necessary removal.

---

[203]   U.S. Department of Energy. *Evaluating the Effects of Selective Catalytic Reduction and Ammonia on Mercury Speciation and Removal*, Product ID# 1005230 (December 2001).

2. How Does Process Configuration Affect Mercury Speciation And Removal?

As discussed above, process configuration refers to how the power plant is designed. In particular, it refers to what post-boiler equipment is installed on the plant, and how that post-boiler equipment is configured. The type of equipment and its configuration in turn determines whether the flue gas exit temperature will be hot (above the acid dew point), saturated (above the saturation temperature) or wet (saturated with water vapor).

Section II of this paper described how two factors have the greatest impact on the chemical structure of mercury in flue gas: chlorine content of coal, and final temperature of the flue gas. Where there is less than 100 ppm chlorine in the coal, the flue gas will contain predominantly elemental mercury. Where there is more than 500 ppm chlorine in the coal, however, the form of the mercury is determined primarily by the temperature of the flue gas in the final process component. At flue gas temperatures above $500^{o}F$, the reactions that result in formation of ionic mercury tend not to occur, such that the mercury in flue gas remains in the elemental form in which it left the boiler. Because process configuration determines final flue gas temperature, it in turn determines the form of mercury that is present in the flue gas, assuming sufficient chlorine is present in the coal to allow formation of ionic mercury.

As shown in the following chart, the ICR stack test data demonstrates this relationship. The chart plots the average chlorine content of the coal used during the stack tests against the fraction of the mercury emitted from the stack in the elemental form. For these tests, all of the lignite and subbituminous coals used had chlorine contents of about 300 ppm or less. Lignite and subbituminous coals resulted in mercury emissions containing at least 80% elemental mercury at least three quarters of the time, and at least 50% in all but three cases. Since this data represents a wide variety of process configurations, it suggests that emissions speciation from these coals is not strongly linked to process configuration.

Percent Elemental Hg vs Coal Chlorine
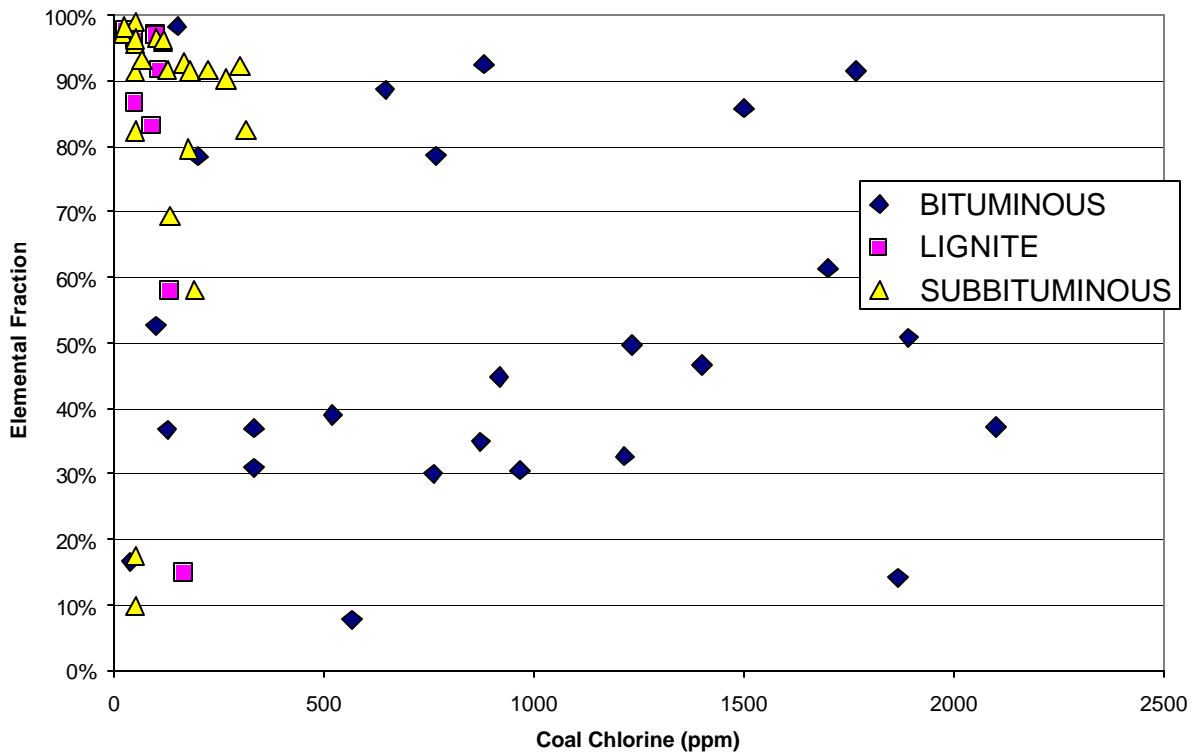
This chart also shows that the bituminous coals used for the ICR stack testing had chlorine concentrations that varied considerably. On the lower end, coals burned by some western units had chlorine contents of 300 ppm or less. It is assumed that these units burn western bituminous coals, which have a similar chlorine contents to lignite and subbituminous coals. On the other extreme, some bituminous coals had chlorine contents as high as 2,000 ppm. As the data in this chart shows, however, the mercury emissions from the units using bituminous coals varied greatly in the fraction of elemental mercury present in the flue gas. This suggests that the fraction of elemental and oxidized mercury in the flue gas of these units is dependent upon chlorine content as well as process configuration.

As discussed in Section IV.B.3, above, existing power plant particulate control devices are quite effective at removing particulate-bound mercury. FGDs can be moderately to very effective at removing ionic or oxidized mercury, but remove essentially no elemental mercury and in some cases will reduce some oxidized mercury back to elemental mercury, resulting in higher concentrations of elemental mercury at the outlet than at the inlet. Cold-side ESPs and, to a lesser degree, hot-side ESPs have some effectiveness at removing oxidized mercury but remove essentially no elemental mercury.

As discussed in Section IV.B.3, above, fabric filters also have some effectiveness at removing ionic mercury.[204] While the data suggest that these units may be able to remove elemental mercury as well, researchers believe a more probable explanation is that, with certain low chlorine content coals, the ash has sufficient unburned carbon to allow adsorption or solid catalyzed reactions to occur within the filter itself.[205] In the latter, mercury in the flue gas comes in intimate contact with ash particles and is converted to oxidized forms, making it more readily adsorbed onto the ash. As a result, researchers believe that actual removals for fabric filters may vary significantly from what would otherwise be predicted, based on ash characteristics that were not evaluated when EPA conducted its mercury study.[206] Spray dryer/fabric filter combinations are highly effective at removing oxidized mercury, do not remove elemental mercury, but may also catalyze a reaction of elemental to ionic mercury within the filter/spray dryer when sufficient chlorine is present in the coal.

In section IV.C.1, this document identified the three different process configurations of hot stack, saturated stack and wet stack. Each process has a characteristic final temperature that is dependent upon how that process is configured. The following chart compares stack temperature on the X-axis with mercury emission rate on the Y-axis. (Note that the Y-axis uses a logarithmic scale.) The hot stack process configuration typically has temperatures in excess of about 250°F (right portion of the graph). By comparison, the saturated stack process configuration has temperatures less than the hot stack, but above about 160°F (center portion of the graph). Finally, the wet stack process configuration has temperatures that are less than 160°F (left portion of the graph).

It should be noted that the temperature range given for each process configuration is approximate and can vary. For example, the ICR stack data show one unit with a particulate scrubber burning subbituminous coal having a final temperature of about 192°F. However the data does show the processes are reasonably well grouped.[207]

---

[204]   Electric Power Research Institute, *An Assessment of Mercury Emissions from U.S. Coal-Fired Power Plants*, p. 3-30 (September 2000).

[205]   *Id.*

[206]   *Id.*

[207]   Note: In the original ICR database supplied by EPA, the stack temperature which was provided for the Lowman, Morrow and Monticello units was downstream of the FGD bypass. For graphing purposes, the absorber outlet temperature was used instead.

ICR Mercury Emission Data By Coal Type and Process
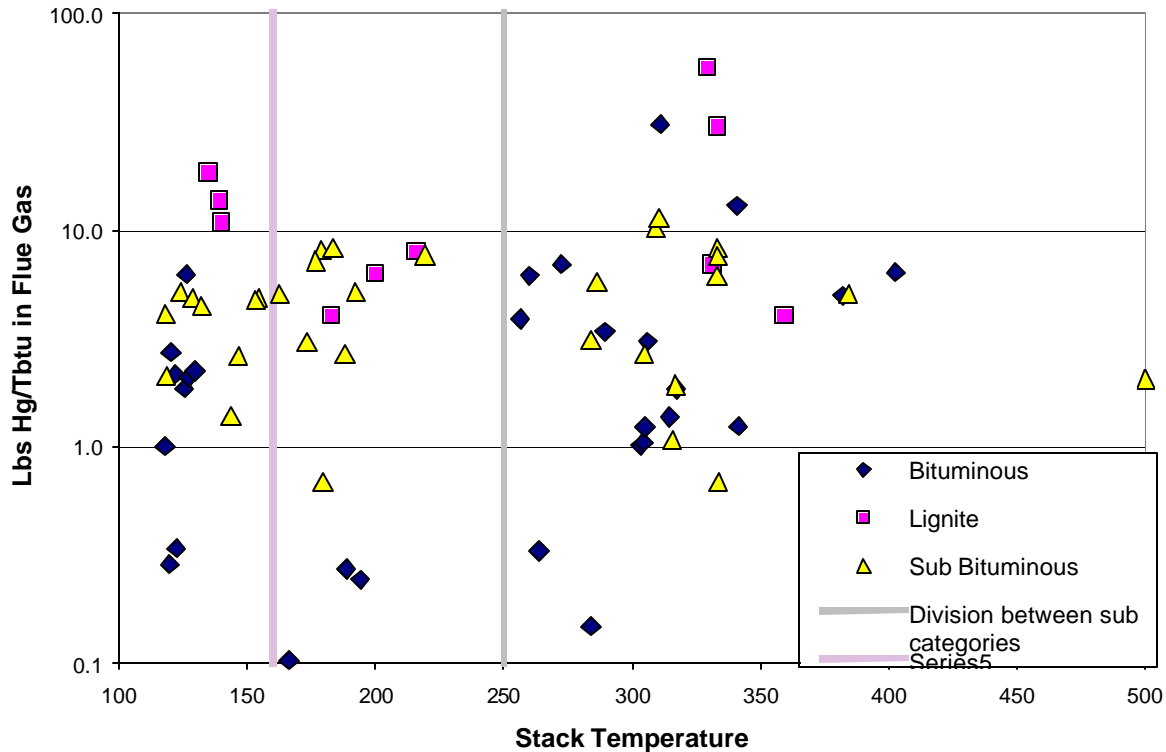
This chart demonstrates how the magnitude of mercury emissions is dependent upon process configuration. For example, in the hot stack process configuration, the units tested above 1.0 lb Hg/Tbtu with only two exceptions. The first is the Valmont Unit, which had a stack temperature of about 284°F and an emission rate of about 0.14 lb/TBtu. Valmont uses a western bituminous fuel which has a very low average concentration of mercury, approximately 0.030 ppm. Moreover, the plant's low emissions are even more misleading since the coal used during the test had an even lower mercury content – about 0.008 ppm. As a result, the emission rate at the boiler outlet was approximately 0.9 lb/Tbtu, using the F factor value. In other words *this unit's coal started out at a lower level than the outlet of all other bituminous units in that category*. Thus, when comparing performance with other units, it would be appropriate to normalize the results from this unit. As an example, the outlet emission rate could be scaled upwards using the ratio of the average mercury in the units coal divided by the concentration in the test coal (0.030 ppm/0.008 ppm). This would increase the rate by a factor of about 5 and then the results would be more comparable to other units in that category.

The second exception is the Salem Harbor Station, which was previously discussed. This unit has very high levels of unburned carbon in its flue gas and unusually high residence times. In addition, the fuel used during its test was also very low in mercury content (0.027 ppm). Both factors would account for the unusually low outlet mercury levels from this plant.

The above chart also shows that after considering the exceptions noted above, the Saturated Stack and Wet Stack configurations have units that perform better than the Hot Stack configuration. However, in the West Stack category, the Intermountain Unit also uses a low mercury western bituminous coal, which results in a considerably lower outlet mercury emission rate. This is understandable because of the lower temperatures involved and the nature of the different equipment installed in that configuration. Subbituminous and lignite units on the whole performed more poorly.

Accordingly, process configuration determines the final temperature of the flue gas, which in turn impacts the type of mercury compound that will be formed in the flue gas. The type of mercury compound in turn determines the effectiveness of air pollution control devices at removing mercury from the flue gas. Thus, process configuration impacts the effectiveness of mercury removal technologies. In summary, the combination of process configuration and fuel rank (including the effects of chlorine), present plant operators with very different problems relative to reducing mercury emissions – and these different problems will require different solutions.

3.   Rationale for Subcategorizing Based On Process Configuration

Like coal rank, process configuration – in particular, the flue gas temperature that results from the process configuration – has a critical impact on the specific mercury-containing chemicals that exist in the flue gas. This mercury speciation, in turn, impacts the effectiveness of existing control technologies at removing the mercury-containing compounds. Specifically, where process configuration (or coal rank) results in predominantly elemental mercury being present in the flue gas, there is no control technology on any *existing* plant that will effectively remove the elemental mercury from flue gas.[208]

For the same reasons that it is appropriate to subcategorize based on coal rank, it is appropriate to subcategorize based on process configuration. Specifically, in numerous past MACT standards, EPA has created subcategories where differences among sources affected the *performance* of control technology and, hence, the achievability of the MACT standard. Examples include the steel pickling MACT, the phosphoric acid manufacturing MACT, the coke oven battery MACT, the leather finishing operations MACT and the secondary aluminum production MACT.

A similar approach is warranted here. As discussed above, Congress clearly contemplated that EPA would distinguish among sources types where differences affect the feasibility and effectiveness of control. That is certainly the case here – both for coal rank and process configuration. Importantly, the removal efficiency that can be achieved *does not depend* primarily on how well a source operates and maintains its pollution control equipment. Rather, removal efficiency depends primarily *on what chemical form the mercury takes when it reaches the air pollution control device*.

---

[208]   Although in some cases, a specific plant may succeed in getting a reasonable degree of elemental mercury removal, this removal results from a confluence of factors (such as high ash content and long residence time) that cannot be universally applied throughout the industry.

The best available technology currently in use at power plants – maintained and operated to ensure maximum performance – will remove almost no mercury from the flue gas if the mercury is present in its elemental form. In contrast, the air pollution control device will remove almost all particulate mercury, and most existing devices have some degree of effectiveness at removing oxidized mercury as well. Thus, the achievability of the standard is tied to the type of the mercury-containing compound in flue gas – which in turn is tied both to process configuration and coal rank. Under these circumstances, subcategorization is both appropriate and consistent with the language of the Act, the legislative history, case law and past Agency practice.

The Agency's coke oven battery MACT standard is particularly illuminating. "Coke" is manufactured from coal, and is one of the basic materials that is used in blast furnaces for the conversion of iron ore to iron. There are two basic types of coke oven batteries. Under EPA's MACT standards for this source category, a "by-product coke oven battery" is defined as a "source consisting of a group of ovens connected by common walls, where coal undergoes destructive distillation under positive pressure to produce coke and coke oven gas, from which by-products are recovered." 40 C.F.R. § 63.301. A "nonrecovery coke oven battery" is defined as "a source consisting of a group of ovens connected by common walls and operated as a unit, where coal undergoes destructive distillation under negative pressure to produce coke, and which is designed for the combustion of the coke oven gas from which by-products are not recovered." *Id.*

These two types of sources use exactly the same chemical input (coal), employ the same chemical process (destructive distillation), produce exactly the same output (coke), and have the same type of emissions (coke oven emissions). Yet EPA established separate standards for by-product and nonrecovery coke oven batteries. For example, by-product coke oven doors are required to control leakage to a maximum of 6.0% (for tall by-product coke oven batteries) and 5.5% (for short by-product coke oven batteries). 40 C.F.R. § 63.302(a)(1)(i)(A) & (B). Nonrecovery coke oven doors are required to control leakage to 0.0% - a far more stringent level of control. 40 C.F.R. § 63.303(a)(1)(i).

Although the preambles to the proposed and final rule do not explain why by-product and nonrecovery coke oven batteries were treated differently, it is obvious from the standards themselves that better control is *achievable* for nonrecovery coke oven batteries than for by-product coke oven batteries.[209] Because by-product coke oven batteries could not achieve the level of control that nonrecovery coke oven batteries could achieve, EPA treated them as separate subcategories (although the rule never explicitly describes the different types of sources as separate subcategories).

Implicit in EPA's creation of differential standards is a conclusion that MACT standards were not intended to require existing sources to completely change their processes. In other words, even though nonrecovery coke oven batteries can achieve far better levels of control than by-product coke oven batteries, EPA did *not* attempt to require all existing by-product coke oven batteries to convert their processes to nonrecovery coke oven batteries. EPA's approach is

---

[209]   *See* 57 Fed. Reg. 57534 (December 4, 1992) (proposed rule); 58 Fed. Reg. 57898 (October 27, 1993) (final rule).

clearly consistent with the law: Section 112(d) is intended to ensure that sources install and operate the "maximum achievable control technology." It is *not* intended to require sources to fundamentally rebuilt their plants or reconfigure their processes.[210]

For the same reasons that EPA established separate MACT standards for the two types of coke oven batteries, the Agency should similarly subcategorize power plant sources based on their process configuration. The type of process configuration has a critical impact on mercury speciation and, hence, on effectiveness of removal and achievability of the standard. MACT standards were not intended to – and should not – result in sources being required to fundamentally reconfigure their plant processes. Accordingly, subcategorization is appropriate.[211]

It may be, however, that subcategorization based on process configuration is not necessary for subbituminous and lignite coals. For these coals, which typically have low chlorine contents, the chlorine content of the coal – rather than process configuration – likely will be the primary determinant of the type of mercury-containing compound that is present in the flue gas. For bituminous coals, however, which typically have higher chlorine content, the process configuration likely will be the primary determinant of the type of mercury-containing compound in the flue gas. In other words, for subbituminous and lignite coals, process configuration may not have a substantial impact on the effectiveness of control technology – and hence the achievability of the standard. But for bituminous coals, process configuration will be the predominant influence on control technology effectiveness and standard achievability – making process configuration a highly appropriate basis for subcategorization of plants burning this type of coal.

---

[210]   *See*, *e.g*. H.R. Rep. 101-490, Part 1 at 328 (1990) ("MACT is not intended to require unsafe control measures or to drive sources to the brink of shutdown.").

[211]   Similarly, EPA's hazardous waste combustor rules create three separate subcategories depending on the process configuration of the source that is burning the hazardous waste: hazardous waste incinerators, hazardous waste cement kilns, and hazardous waste burning lightweight aggregate kilns. 64 Fed. Reg. 52828 (Sept. 30, 1999). A hazardous waste incinerator is defined as an enclosed, controlled, flame combustion device. 40 C.F.R. § 260.10. A hazardous waste burning cement kiln is "rotary kiln" that "burns hazardous waste at any time" and produces "clinker by heating limestone and other materials for subsequent production of cement." 40 C.F.R. § 63.1201. And a hazardous waste lightweight aggregate kiln is a "rotary kiln" that "burns hazardous waste at any time" and "produces clinker by heating materials such as slate, shale and clay for subsequent production of lightweight aggregate." *Id*. While all three types of sources burn hazardous waste, they utilize different processes to do so. *See also* 67 Fed. Reg. 9155, 9158 (Feb. 27, 2002) (creating a subcategory that accommodates specialty leather finishing, agreeing with commenters that there were no suitable replacements for the solvents used in their processes, and the MACT standard would be unachievable at current HAP emission rates).

CONCLUSION

For the foregoing reasons, we believe that EPA legally can – and as a policy matter should – create subcategories of power plant boilers based on method of combustion, coal rank, and process configuration, as set forth below:

- Fluidized Bed Combustors; and

Basis	Hot stack (above acid dew point)	Saturated Stack (above saturation temperature)	Wet stack (saturated with water vapor)
Eastern Bituminous coal	Eastern Bituminous/Hot Stack subcategory	Eastern Bituminous/Saturated Stack subcategory	Eastern Bituminous/Wet Stack subcategory
Western Bituminous coal	Western Bituminous/Hot Stack subcategory	Western Bituminous/Saturated Stack subcategory	Western Bituminous/Wet Stack subcategory
Subbituminous coal	Subbituminous/Hot Stack subcategory	Subbituminous/Saturated Stack subcategory	Subbituminous/Wet Stack subcategory
Texas Lignite[212]	Texas Lignite/Hot Stack subcategory	Texas Lignite/Saturated Stack subcategory	Texas Lignite/Wet Stack subcategory
North Dakota Lignite	North Dakota lignite/Hot Stack Subcategory	North Dakota lignite/Saturated Stack Subcategory	North Dakota lignite/Wet Stack Subcategory

Doing so would result in between 8 and 16 subcategories in a sources category of almost 1100 units – for an average of approximately between 70 and 140 units per category (although in reality, the categories probably would not be quite so evenly distributed). [213]

DC_DOCS\435149.4[W2000]

---

[212] Texas lignite is also sometimes referred to as "Gulf Coast lignite." Similarly, North Dakota lignite is sometimes referred to as "Fort Union lignite."

[213] Further analysis of the entire ICR database may allow reductions in the number of subcategories. For example, it may be possible to combine some of the five categories of coal rank. Also, subcategorization based on process configuration may not be necessary for coal ranks where mercury speciation and removal are not shown to be sensitive to process variations.