



GUIDANCE DOCUMENT ON STARTUP AND SHUTDOWN UNDER MATS

INSTITUTE OF CLEAN AIR COMPANIES

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Abstract: The Mercury and Air Toxics Standards (MATS) rule as well as the Industrial Boiler Maximum Achievable Control Technology (MACT) rule contain provisions related to monitoring and operation of air pollution control (APC) equipment during startup and shutdown of coal-fired boilers. Periods of operation, especially during boiler startup, are characterized by rapid transient changes in flue gas composition, quantity, temperature, and moisture conditions. Between a coal-fired boiler and stack, the APC equipment and systems may include selective non-catalytic reduction (SNCR), selective catalytic reduction (SCR), dry sorbent injection (DSI), activated carbon injection (ACI), wet or dry flue gas desulfurization (FGD), and particulate collectors such as an ESP, a fabric filter baghouse or both. For startup and shutdown conditions, the APC equipment and systems cannot be viewed as single standalone entities anymore but must be viewed as an integrated APC system with proper operation not only dependent on the boiler flue gas characteristics but also dependent on the proper operation or the lack thereof of the APC equipment upstream. The objective of this document is to provide operators of coal-fired boilers with guidance on safe and effective methods of starting the APC equipment and on measurement issues in order to comply with EPA's startup and shutdown provisions in the MATS and IB MACT rules as well as startup rules that become part of operating permits.

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1 Introduction

1.1. Who is ICAC

The Institute of Clean Air Companies (ICAC) is the national non-profit trade association of companies that supply air pollution control and monitoring systems, equipment, reagents, and services for stationary sources. ICAC has promoted the air pollution control industry and encouraged the improvement of engineering and technical standards since 1960. Our members include over 90 companies who are leading manufacturers of equipment to control and monitor emissions of particulate matter (PM), volatile organic compounds (VOC), sulfur dioxide (SO₂), nitrogen oxides (NO_x), hazardous air pollutants (HAP), mercury, acid gases, and greenhouse gases (GHG). Therefore, ICAC is in a unique position to provide technical guidance on the startup and shutdown provisions of the Mercury and Air Toxics Standard (MATS). ICAC's collective technical expertise is, and will continue to be, an important resource for coal-fired boilers facing challenging new regulations.

1.2. Objectives

Periods of operation, especially during boiler startup, are characterized by rapid transient changes in flue gas composition, quantity, temperature, and moisture conditions. As discussed in the Environmental Protection Agency (EPA) training manuals for fabric filters (FF)¹ and electrostatic precipitators (ESP)² in the section on startup and shutdown, improper startup and shutdown can not only damage the equipment but also result in performance degradation that may result, depending on its severity, of the ESP or fabric filter not meeting its design outlet emission requirements.

Many components in modern power plants such as steam turbines and auxiliary steam systems limit and control the manner that boilers start up. The problems are aggravated with installation of multiple air pollution control (APC) equipment and processes, especially those required to achieve Mercury and Air Toxics Standards (MATS) compliance. Between a coal-fired utility boiler and stack, the APC equipment and systems may include selective non-catalytic reduction (SNCR), selective catalytic reduction (SCR), dry sorbent injection (DSI), activated carbon injection (ACI), wet or dry flue gas desulfurization (FGD), and particulate collectors such as an ESP, a fabric filter baghouse or both. For startup and shutdown conditions, the APC equipment and systems cannot be viewed as single standalone entities anymore but must be viewed as an integrated APC system with proper operation not only dependent on the boiler flue gas characteristics but also dependent on the proper operation or the lack thereof of the APC equipment upstream.

The problems related to low flue gas temperature during boiler startup can also occur on boiler shutdown. Corrosion problems can develop in the boiler and throughout the flue gas path. Only a few examples have been presented of the performance degradation that can occur if particulate control equipment is started up prematurely. It is critical that proper startup and shutdown procedures are developed and followed for an integrated APC system installation to assure that the APC equipment operates at optimum levels to meet design gaseous and particulate emissions removal requirements when desired boiler load is reached.

The objective of this document is to provide operators of coal-fired boilers with guidance on safe and effective methods of starting the APC equipment and on measurement issues in order to comply with EPA's startup and shutdown provisions in the MATS rule and the Utility NSPS. In addition we anticipate

that startup and shutdown rules may be added to operating permits for plants that may not be covered by the MATS rule. This document provides general guidance for good engineering practice for coal fired plants.

2 Overview of MATS Startup and Shutdown Provisions

2.1 Introduction

The MATS startup and shutdown provisions apply to both electricity generating units (EGUs) and industrial boilers. This overview does not include an analysis of the rules related to integrated gasification combined cycle (IGCC) plants.

These rules apply to startup and shutdown under MATS and to the startup and shutdown provisions for the PM standard in the utility New Source Performance Standard (NSPS), and industrial boiler (IB) National Emission Standards for Hazardous Air Pollutants (NESHAP), i.e. IB Maximum Achievable Control Technology (MACT). The rule amends the startup and shutdown provisions of the MATS rule and utility NSPS finalized in February 2012, and aligns the requirements with IB MACT (40 CFR 63 Subpart UUUUU and 40 CFR 63 subpart Da). The NSPS part of this rule only covers particulate (PM) emissions. Based on recent court decisions, EPA has directed states to make changes to Startup and Shutdown provisions in air permits by issuing a State Implementation Plan (SIP) call for consistency with the new startup and shutdown rules.

EPA states that it believes that the final rule includes enough variability for sources to include startup and shutdown periods in the rolling average emission rates, and also that the best-performing sources can meet the standard during startup and shutdown periods. However, EPA acknowledges that for startup and shutdown periods, there is a lack of hazardous air pollutant (HAP) data and there are some challenges with measurements, and these have led EPA to establish work practice standards. EPA describes this November 2014 final rule as “very similar” to and no more stringent than the February 2012 final rule’s requirements. In summary this final rule:

- Finalizes the startup and shutdown requirements in February 2012 rule (Option 1 in the final rule).
- Provides alternative work practice standard as an option for startup (Option 2 in the final rule).

For a given EGU, emissions data may be identified as being within a startup period or a shutdown period, and emissions data within these periods will not be included in the compliance averaging period. However, both continuous monitoring system (CMS) measurements and certain recordkeeping and reporting requirements apply to startup periods and shutdown periods. The rule is based on a 30-day or 90-day boiler operating averaging period for emissions and EPA’s belief that sources can over-control to make up for periods when their emissions are higher than the rolling average limit. Theoretically, if unit stability is not achieved for some reason within the defined startup period, this can still be averaged out over the full 30 or 90 days.

EPA used a statistical approach to determine the best performing 12 percent of EGUs by selecting those EGUs that were able to engage their Air Pollution Control Devices (APCDs) most quickly after the initial generation of electricity or thermal energy.³ These data were obtained from EPA’s Clean Air Markets Division (CAMD). EPA averaged that time to determine the end of the startup period when the numeric standards for currently regulated criteria pollutants would become applicable.

2.2 Startup Provisions

EPA's rulemaking allows the operator to select one of two methods of determining compliance during startup periods, Option 1 and Option 2 as described below. Both options have the following things in common:

- CMS must be active for any period of fuel firing*. Data collection and calculations such as the pollutant emission rate for each hour of startup are required. Recordkeeping and reporting requirements are fairly extensive, as provided in §63.10032 and §63.10021(h).
 - For common stacks: When electrical load of a contributing unit is zero, use 5% of maximum electrical load as the default value in calculations of emission rates. As soon as the load is non-zero, the indicated value must be used.
- In either of the Options below, the startup period begins with the first firing of fuel in the boiler for any purpose. The exception is if the boiler has not operated previously, in which case startup begins with first-ever firing of fuel for the purpose of generating electricity or useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes.
 - Two types of fuels are identified in the rules: the startup or auxiliary fuel (e.g., natural gas, distillate oil) and the primary fuel (coal, residual oil or solid oil-derived fuel). It should be expected that the unit will require introduction of the "primary fuel" before flue gas conditions are sufficient for starting the APC equipment. The gas and oil ignition systems that are available for startup are typically sized to achieve 10% of the fuel heat input, with some variances in Class 1, 2, or 3 ignition systems as per National Fire Protection Association (NFPA) 85 standard requirements.

2.2.1 Option 1

Must comply with all MATS and NSPS standards at the time of electricity generation or useful thermal energy production.

- Must use "clean" fuel for ignition.
- Startup ends when first power is generated or useful thermal energy is produced. Any fraction of an hour counts as a full hour. This fraction of an hour is the first MATS compliance hour and defines the first boiler operating day for the purpose of calculating the 30 boiler operating day average.

When the startup period includes burning the primary fuel:

- Must engage all of the applicable control technologies except:
 - Do not have to engage dry flue gas desulfurization (DFGD) or SCR until required to meet standards during normal operation;
 - Engage DFGD and SCR, if present, to comply with relevant standards applicable during normal operation. NOTE: This needs clarification from EPA.
 - Must comply with all applicable emissions limits at all times except for periods that meet the applicable definitions of startup and shutdown. Required to meet all Clean Air Act (CAA) or State Permit limits.

* EPA questions the ability to measure HAPs at the start of electrical generation, but wants to gather data during startup and shutdown to assist with determining any changes for the eight-year residual risk review of the standards.

2.2.2 Option 2

Must comply with all MATS and NSPS standards within four hours of the time of electricity generation or production of useful thermal energy.

To utilize Option 2 there are additional reports and information that need to be provided to EPA by an independent professional engineer. The report must be submitted with the EGU's Notification of Compliance Status and must show the following:

- How the current condition of the PM device, including any modifications, can meet the rule requirements.
- Time needed to engage PM device after initial fire.
- PM device effectiveness at initial operation and under normal operation.
- PM emission rate.
- Uncontrolled PM emission rate.
- The capacity of auxiliary fuels for each unit.

Clean auxiliary fuels defined in § 63.10042 must be utilized to the maximum extent possible throughout the entire startup period. The EGU must have sufficient clean, auxiliary fuel capacity to engage and operate the PM control device within 1 hour of adding primary fuel to the unit.

- PM equipment must be engaged no more than one hour after firing primary fuel.
- Engage all other APCDs as expeditiously as possible, and in any case to support all other emission standards.
- Must meet the startup period work practice requirements as identified in §§63.10020(e).

Startup ends four hours after any power is generated.

- All MATS compliance tracking, recordkeeping and compliance requirements resume the hour that startup ends. For example, if the unit first generates power at 0300, MATS resumes at 0700. If the unit first generates power at 0350, MATS resumes at 0700. The hour at which the Startup Period ends is the hour at which all compliance standards resume.

In the event of concern about safety of operation or inability of a source to comply, the source can apply to the administrator for an EGU-specific case-by-case emission standard. This requires:

- That the manufacturer of device certifies that there is a safety issue, and
- Proof that the APCD is adequately designed to meet the final limit
- Among other specifics described at 40 CFR 63.10011(g)(4)

2.3 Shutdown Provisions

Shutdown begins when the EGU no longer generates electricity or makes useful thermal energy when primary fuel is being fired in the EGU, or upon cessation of primary fuel, whichever is earlier. Shutdown ends when the EGU no longer generates electricity and fuel is not fired. Any fraction of an hour in which shutdown occurs constitutes a full hour of shutdown.

The plant must operate all CMS during shutdown as well as collect appropriate data, and calculate the pollutant emission rate for each hour of shutdown. In addition, the plant must operate all applicable control devices and continue to operate those control devices after the cessation of primary fuel being fed into the EGU and for as long as possible thereafter considering operational and safety concerns.

The plant must operate APCDs when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than the MATS and that require operation of the control devices.

2.4 Other Provisions of the Rule

Diluent cap for non-IGCC boilers: default values may be used for calculations of emission rates during startup and shutdown periods for CO₂ and O₂:

Default of 5% for CO₂ when CO₂ is less than 5%;

Default of 14% for O₂ when O₂ is above 14%.

The rule provides for three alternative approaches that can be used for mercury measurements during startup and shutdown.

1. Use CEMS at all times.
2. Use two separate sorbent trap systems and switch at startup/shutdown.
3. Use a single sorbent trap system and include startup and shutdown periods in compliance averaging period (30-day or 90-day).

There are extensive reporting requirements for each startup and shutdown detailing startup fuels, time, and equipment performance.

Default power generation: for calculations that use the electrical output, when generation is zero (common stack or otherwise), calculations should use 5% of the maximum generation. Once any generation is recorded, however small, that value must be used in calculations.

Work practice standards for startup of PM control equipment are matched among MATS and industrial boiler NESHAP and NSPS.

3 Summary of the Startup and Shutdown Processes in Coal-Fired Boilers

EPA in their statistical evaluation of plant operating conditions,¹ stated that there are three startup conditions as follows:

- **Hot startup;** A startup event in which the EGU was off line for 24 hours or less before starting to combust fossil fuels.
- **Warm startup;** A startup event in which the EGU was off line for 25 to 119 hours before starting to combust fossil fuels.
- **Cold startup;** A startup event in which the EGU was off line for 120 hours or more before starting to combust fossil fuels.

EPA based their definitions of hot, warm, and cold starts using turbine metrics presented in Reference 4.

Starting of a steam generation power plant is an involved process that could, depending on equipment design and thermal conditions, take a relatively short or long period of time prior to the connection of the unit to electric grid. Typically the colder the steam generator is the longer the startup time and connection to the grid. The primary reasons for taking time are: (a) safety and (b) equipment protection.

Each unit has specific operating instruction that are dependent on its design, the reason for the unit being idle (e.g., emergency repair versus equipment maintenance such as replacement of some pressure parts), and the length of time that it was idle (e.g., cold startup).^{5,6} In addition, most air pollution control devices were designed to operate and contractually guarantee destruction removal efficiency (DRE) under normal operating conditions for which it was designed. It would not be wise to expect efficient operation or the type of efficacy expected when the control device encounters conditions during a startup versus a normal operation or maximum operation, as discussed later.

In a typical startup that follows the replacement of pressure parts, for example, chemical cleaning and steam blowing maybe required to clean the water/steam side of the boiler of construction debris (e.g., welding slag). The process of steam blowing involves the use of high pressure steam from the boiler, itself requiring the firing of fuel in the boiler. The length of time depends on the extent of the repairs carried out and amount of “foreign” material in the boilers piping/tubing.

If there is no “steam blow” required, the normal startup involves several steps that impact the time that it takes for the unit to “synchronize” and connect to the grid. The following are some of the issues that impact the length of the startup process as well as the emissions during that time.

a. Unit Purging

Prior to the introduction of fuel in any unit, or following shutdown, the NFPA recommends that a minimum flow of combustion air representing at least 25% to 40% of the full load air flow is introduced to boiler for a minimum of five minutes, or a flow rate of air that evacuates five times the total volume of the boiler is introduced to the boiler. This is to ensure that the unit is purged of fuel and combustion products from the inlet of the forced draft (FD) fan through the stack. Once the purging period is completed the purge air flow rate is maintained throughout startup. The minimum flow rate applies even if the fuel flow is significantly lower than 25% resulting in very high excess air levels. If the unit has been “synchronized” to the grid at low boiler loads (e.g., 10 – 15%) and firing coal (primary fuel) it is still operating with the minimum air flow of 25% or very high excess air levels.

The high levels of excess air during startup dilute the low levels of CO₂ resulting in a high bias in the CEMS measurements, for example, reporting high levels of SO₂. This dilution effect is a result of the calculation methods used to convert the measured CEMS emission in parts per million (ppm) to the emissions rate of pounds per million Btu (lbs/10⁶Btu) as required by the EPA.

b. Water Chemistry

The boiler requires demineralized water with strict requirements as to its mineral content in order to protect the boiler and steam turbine. During startup the chemistry of the water used in the boiler is closely monitored to ensure that the steam generated and sent to the turbine has minimal impurities. In addition to minerals in the water, the boiler tubes themselves could contain mineral “scale” or deposits that are sometimes dislodged and enter the water/steam path due to the thermal gradients experienced during the unit’s startup. If the unit operators notice increased levels of minerals in the water, they will adjust the firing rate, typically they will “slow it down”, to ensure that they have the proper chemistry. Significant delays in startup can result from water cleanliness “holds”.

c. Superheater and Reheater Protection

When the unit first starts up, it does not generate any steam so there is no flow of steam to cool these heat transfer surfaces. As a result the boiler operators, depending on the materials used, maintain the flue gas temperatures entering the superheater and reheater sections of the boiler at less than 900 °F

(carbon steel) or 1000 °F (alloy or stainless steel). This is done by firing at a low rate, and the length of time of this low-rate firing is dependent on (a) the generation of sufficient quality of steam to send to the turbine, and (b) the warming of the turbine.

d. Turbine Warming

During startup extra care is taken to minimize thermal stresses of the steam turbine components due to thermal expansion. Specifically the heat-up rate of critical steam turbine components (e.g., main shaft) is closely monitored and the firing rate of the boiler is varied to adjust the production and temperature of the steam going to the turbine. The length of turbine warming is less than that of the boiler.

However, it should be pointed out that the turbine, depending on its initial thermal condition (i.e., hot, cold or warm), would require some warm-up time to reach full load so it is not damaged due to thermal stress. It should be noted that occasionally the turbine will trip during startup requiring the process to be repeated with potential associated emissions penalties.

e. Minimizing Boiler Thermal Stresses

Large boiler parts require special attention during startup and shutdown since they undergo significant thermal stresses. Items such as thick headers and the drum have their temperatures closely monitored, and hence the firing rate of the boiler is modulated to ensure that equipment thermal stresses are minimized. For example, boiler drums and headers with rolled tube joints must not exceed a maximum heating and cooling rate of 100 °F per hour change in saturation temperature. Higher pressure utility units typically will have a saturation temperature rate of change limit of 200 °F/hr. The economizer, although it is at low temperature due to the lack of water flow when boiler pressure is raised at startup, could start generating steam (i.e., steaming) making the control of water level in the drum difficult and generating “water hammer” (uncontrolled vibration) of the economizer.

The emissions and operating cycles are very different for the three startup conditions. Figure 1 shows flue gas temperature profiles at an air preheater (APH) inlet on a 440 MW coal fired plant during warm startup and cold startup periods. As noted earlier, the duration of the startup is dependent on the speed the system can be brought up in temperature without causing thermal stress.

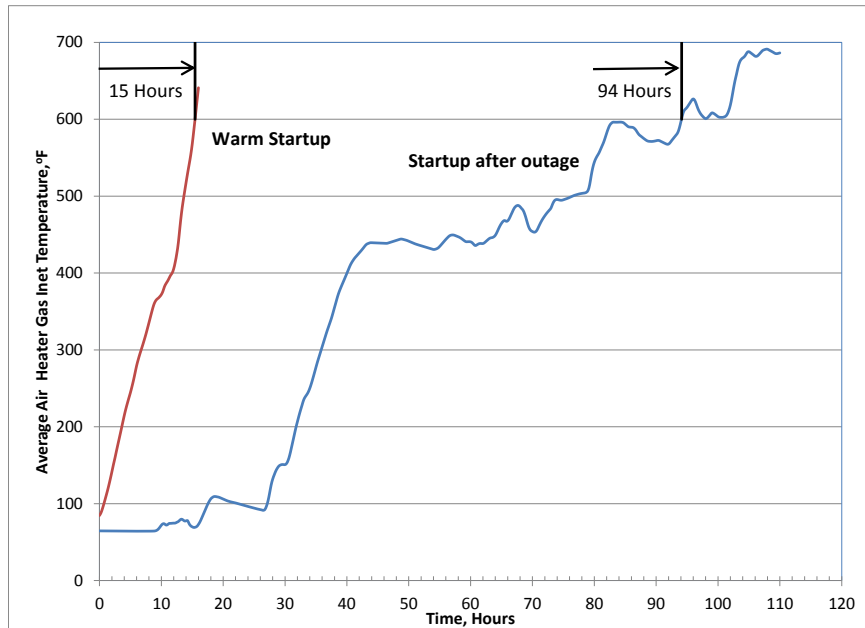


Figure 1. Example of air heater inlet temperature as a function of time for warm startup and cold startup after outage.

Figure 2 and Figure 3 show the same “warm” and “cold” startup data along with generator load and fuel fired. The “warm” data show that the SCR could be brought in service about three hours after the unit was on coal only, which exceeds the four hours after the start of electricity generation allowed under Option 2.

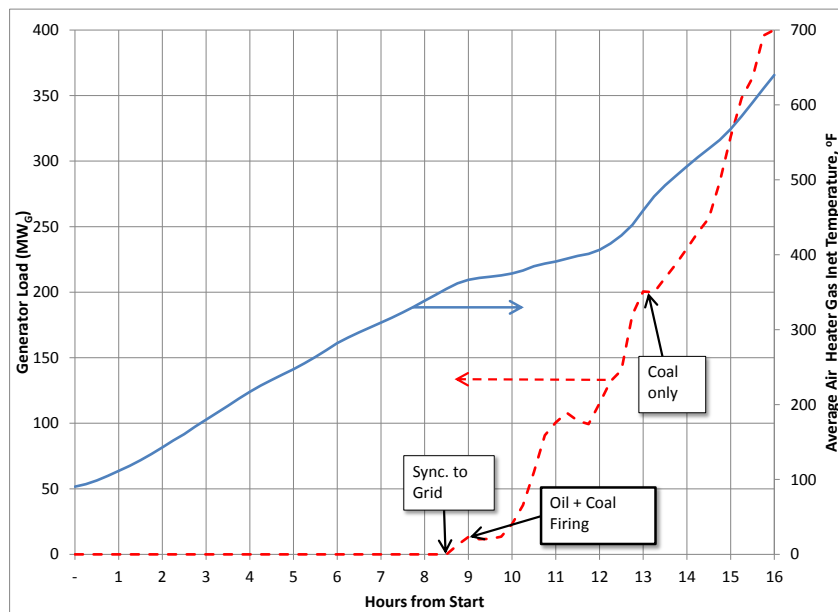


Figure 2. Example of load and air heater inlet temperature as a function of time for a warm startup.

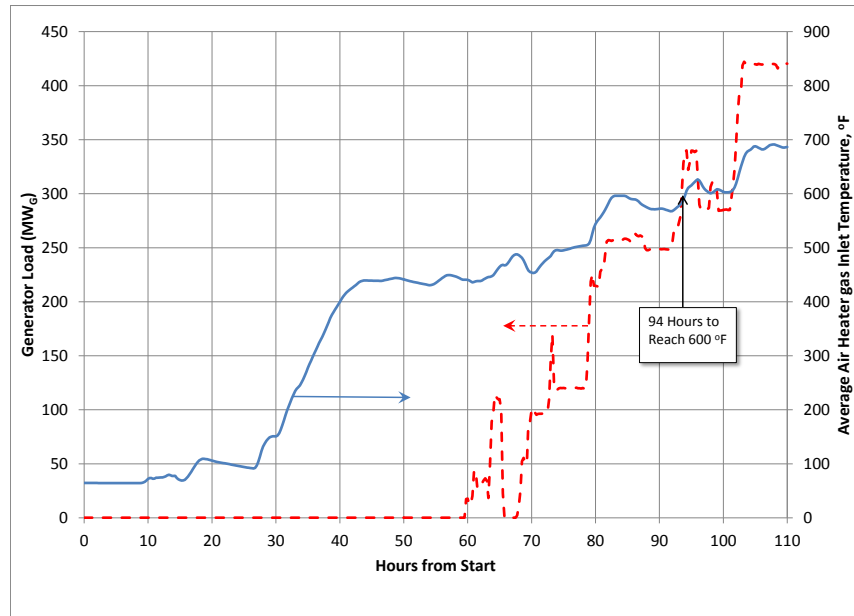


Figure 3. Example of air heater inlet temperature as a function of time for cold startup after an outage.

Syncing to the grid is done after certain temperatures are reached in the steam turbine. The time required to reach temperature is dependent on the temperature of the unit at the beginning of startup to prevent thermal stresses to the system. The operator cannot put load on the generator until the unit is synced to the grid. As soon as there is load on the generator (for example, greater than 1 MW), the unit can be assumed to be on-line. In certain plants coal firing can begin following the sync to the grid. It is frequently no more than twenty minutes after syncing. Other plants require higher loads before firing coal.

The startup fuel is continued until a certain number of coal mills are brought in service. At some plants the startup fuel co-firing with auxiliary fuel continues until half- load is reached and at other facilities it continues until two-thirds- load. The capacity of each plant is different as to its ability to burn an auxiliary or startup fuel. Some plants only have igniters and can burn startup fuel only to about 10% of the design heat input while other plants have fuel burners that can burn auxiliary fuel up to full load. Therefore, it may not be possible at every plant to bring the system up to the temperature needed for APC operation using only clean auxiliary fuel. Some plants may need to consider expanding their oil storage capacity, gas supply lines, and ignition fuel systems, pumps, valve trains, piping, combustion control systems, and burners (beyond the requirements to comply with NFPA 85 standards) in order to accommodate the use of “clean” startup fuels **only** to comply with the MATS startup rule. Modern plants with a moderately sized turbine bypass system will be able to bring the boiler up in load on primary fuel prior to synchronizing the turbine. This can allow the APC system to be put in service prior to the end of startup (defined by start of generation).

In a normal shutdown, operators follow a set procedure in which different APC equipment is removed from service based on manufactures recommendations normally based on flue gas temperatures. Coal firing is reduced until the unit reaches a point where the auxiliary fuel can be brought in service.

In an emergency shutdown or trip situation, different operating conditions apply. For example, in a trip situation ammonia (NH₃) would be shut off immediately to an SCR or SNCR and water or slurry feed discontinued to a spray dryer, circulating dry scrubber (CDS) or Novel Integrated Desulfurization (NID)

system. Emergency cooling water may need to be added to “dry” FGD systems to protect the baghouses. However, slurry or water would continue to be pumped to a WFGD system to protect the equipment until a minimum operating temperature below the limit of fiberglass reinforced plastic (FRP)/plastic components. A purge of the flue gas path must occur as soon as possible after an emergency shutdown is reached.

4 Measurements during Startup and Shutdown

4.1 CEMS issues

The MATS Startup and Shutdown rule requires that all CEMS be on line during the startup period. A startup monitoring plan should be tailored to an individual boiler’s auxiliary fuel and APCDs. The type of startup (hot, warm or cold) might also affect the plan for CEMS during startup. This section also applies to coal-fired boilers subject to the Industrial Boiler MACT.

As noted above, the NFPA recommends that a minimum flow of combustion air representing at least 25% of the full load air flow is introduced to boiler for a minimum of five minutes or at volume that is five times the total volume of the boiler. These high levels of excess air generate low levels of CO₂. The plant has to report stack emission rates (e.g., lb/MMBtu for NO_x and SO₂, lb/TBtu for Hg) during startup, although these readings don’t count toward their compliance targets. The stack CEMS reports quantities in terms of concentrations (e.g., ppm, µg/wscm) and these values must be converted to emission rates. This is accomplished using an F-factor (40 CFR Part 75, Appendix F) that uses the concentration of O₂ or CO₂ in the stack to generate a conversion factor. It is possible to have “errors” in readings of O₂ or CO₂ in the stack due to stratification, instrument error, etc. The relationship between the conversion factor and O₂ concentration is shown in Figure 4 (a similar curve could be generated for CO₂); for high concentrations of O₂, the curve is very steep, meaning that small errors in the measured O₂ would result in significant errors in the conversion factor and, therefore, in the calculated stack emission rate. As Figure 4 illustrates, using the diluent cap (assuming a maximum value of O₂ at 14% or of CO₂ at 5%) is a means to reduce potential errors in calculated emission rates when the excess air is high during startup.

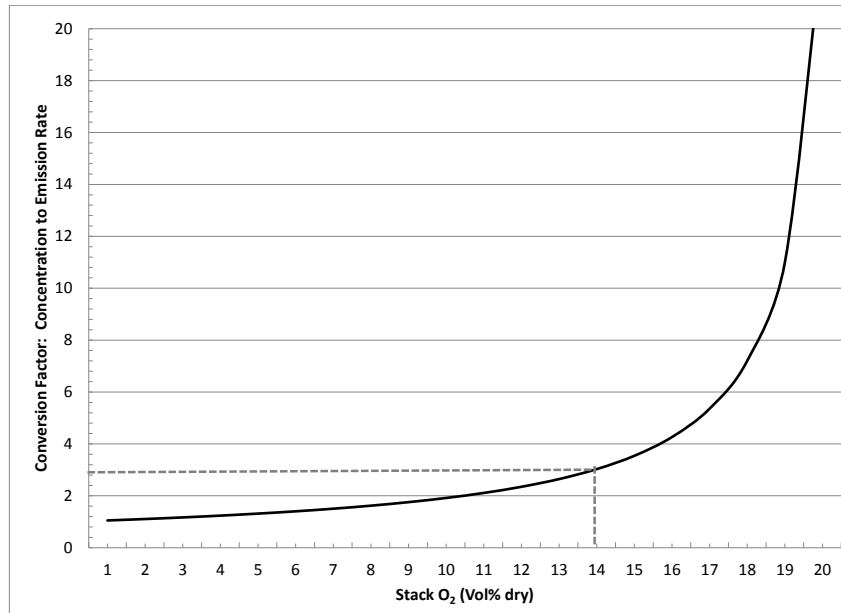


Figure 4. Conversion factor from concentration to emission rate as a function of flue gas O₂ concentration.

During startup testing, there are several issues that should be addressed to get a comprehensive data set that is accurate over the entire startup, upset or shutdown procedure. These data are typically averaged over a 30- boiler operating day rolling average required for MATS compliance. First and foremost it must be noted that, the EPA reference methods and performance specifications were written, designed, and validated to measure emissions accurately only during steady-state conditions and typically required the equipment to be run at full load on a boiler or incinerator. The tests and procedures were validated based upon steady-state conditions when the equipment and ancillary emissions control device equipment reached operating temperatures and flowrates and all other normal operating conditions. During a startup period, there are several issues that must be addressed before the user may feel confident that the data generated are as accurate as possible given the difficult conditions encountered during a startup period.

4.1.1 Flow

Stack flow must be measured to accurately calculate emission loading. Therefore, a flow measurement device must be selected to properly measure along the entire range of flows encountered during a startup or shut-down. It may be necessary to incorporate two different or different calibrated range flow measurement devices so that a proper flowrate may be measured.

Additionally, moisture may affect the flow measurement device. Entrained moisture is an issue for measurements employing pressure drop, but not for ultrasonic instruments. The real key is accurate measurements when the instrument is set up and subsequent Relative Accuracy Test Audits (RATA). Stratification is always a concern but is usually determined in normal RATA procedures.

4.1.2 Calibrations

As a process ramps up to normal operating conditions, it will likely undergo a vast swing in emissions due to both process conditions as well as control device conditions. A complete gaseous matrix investigation should be performed to understand how much of a swing in air toxics as well as in any analytically interfering compounds may be encountered. It is well known that in many optical systems, methane is an interferent for hydrogen chloride (HCl), and the selection of a proper analytical instrument that may compensate for these swings in interferents must also be addressed, and the right

instruments need to be selected as a startup instrument or as a complete system start-up and normal operation system.

If there is a need to validate a CEMS for measurements during startup and shutdown, consideration should be given to conducting RATAs for at least three different loads for the facility to insure that the CEMS can be relied on. For example, the three suggested loads could be a low load (20% of capacity), a mid-load (50-60% of capacity) and a high load (80-100% of capacity). This would also be problematic if the range of the CEMS could not measure as low or high as all the capacity runs.

4.1.3 Temperature and Moisture

Temperature will vary greatly during a startup procedure (see Figures 1 to 3) which will affect many different parameters typically held at a steady-state condition during normal operation. Some of these issues to deal with are expansion which may actually cause changes in excess or dilution air, or increased moisture or condensing moisture from increasing temperature driving moisture off of surfaces or beds. Additionally, some parts of the equipment will heat up faster than others which may cause condensed moisture on colder parts of the system. These potential effects should be investigated and controlled as needed to prevent damage to any instrumental analyzers from condensed moisture or corrosive moisture being carried into the instrument. Moisture effects should not be an issue in a well-designed and maintained CEM system, which includes heated sample lines and probes. However, condensed moisture could plug some flow or velocity measurement devices, creating erroneous data incorporated into a data acquisition system (DAS), which in turn would carry that error through to the final emissions loading reported.

The varying moisture levels must be investigated to identify the full range encountered during a startup or a shutdown period, so that it may be measured accurately because moisture will certainly be used to calculate several different parameters used in the reported emissions loading. Condensing moisture will also cause total flow and pressure changes that must be accurately measured over the test period. A thorough investigation must be performed to address if and how the moisture is calculated by the emissions monitoring CEMS. A good CEM system will have a point-by-point H₂O analysis that is acceptable as an alternative to EPA Method 4.

4.2 Special considerations for mercury measurement: CEMS and sorbent traps

There is very little data available on the performance of mercury capture sorbents, PAC or non-carbon based, during startup and shutdown conditions. Most facilities have utilized sorbent traps for measurements without including, or separating out, these time periods, or have not studied the CEMS data available for these periods as distinct from normal operation. EPA's view appears to be that emissions during startup and shutdown will help the average emission rate over a 30- or 90-day period rather than make it worse. But this may be unit-specific. Gathering information during startups going forward will help operators make decisions on their specific situation and thus implement control technologies or process conditions in a sequence that works.

In some cases, spikes in mercury emissions have been observed as the boiler and flue gas heat up during the startup period. If emissions spikes are known, it is important to characterize them, in terms of magnitude so that trap vendors can supply traps that have the appropriate spike concentrations and so that mercury (Hg) CEMS vendors can supply span or calibration information to meet quality assurance and quality control (QA/QC) needs.

According to EPA, the two options to measure mercury for MATS compliance are either mercury CEMS or sorbent traps. Some potential approaches to mercury measurement during the startup period include:

- Redundant systems, for example, using a mercury CEMS during startup, but then switching to a sorbent trap for stable operation;
- Use of multiple pairs of sorbent traps, for example, one pair for startup and one for stable operation; these could be accommodated by using two different probes containing paired traps or by using a quad-probe.

5 Equipment

The focus of this report is the MATS rule. However, as noted in the introduction, recently EPA has moved to harmonize startup and shutdown procedures, which will mean that the rule may apply more broadly in the future.

The operation of certain APCD equipment on a coal-fired boiler directly affects the emissions of mercury, HCl and metal emissions, which are regulated under the MATS rule: wet and dry scrubbers, particulate matter control devices, dry sorbent injection systems for HCl control, and activated carbon injection systems. Other APCD equipment indirectly affect the removal of mercury: SCRs (which oxidized mercury thus improving removal in scrubbers) and dry sorbent injection systems for SO₃ control (which improves the capture of mercury by sorbents and unburned carbon in fly ash). This section will discuss startup and shutdown considerations for the APCDs listed above. Also included in the discussion are other NO_x control systems (combustion controls and SNCR), because as noted above the recent SIP call concerning startup and shutdown is more broadly applicable.

5.1 LNB/OFA

LNB/OFA is not part of the MATS rule but may be required in operating permits. Combustion controls for NO_x control are widely used in the industry and startup issues have generally been incorporated into plants' procedures. Minimal impact can be expected during startup through changes in burners and OFA design. Moderate startup emissions control may be most affected through efficient selection and setup of those burners used throughout the startup period.

The work practice standards in the MATS rule require that a tuning and/or inspection of the burners be performed every 36 months, or 48 months if a neural network is used. This will affect the frequency and potentially costs of outages, especially where burner design relies on fragile mechanical features to keep the NO_x and CO emissions in control.

5.2 SNCR

SNCR is not part of the MATS rule but may be part of operating permits. SNCR is a post-combustion NO_x reduction method that reduces NO_x through a controlled injection of ammonia or urea into the combustion gas path at a specific reaction temperature range. SNCR systems reduce NO_x when ammonia is injected at flue gas temperatures between 1600°F and 1800°F, or urea is injected when temperatures are between 1600°F and 2200°F, with 1800°F to 2000°F being the optimal reaction temperature range. Injection at temperatures below these ranges can result in excessive unreacted ammonia to slip through the boiler, and injection at higher temperatures will produce less efficient NO_x reduction.

SNCR systems go through startup and optimization, at which point the control strategy is finalized so that the system can meet performance guarantees. This control strategy includes the set points for which levels of injectors will be in service at given boiler load and furnace temperatures. This control arrangement is customized to specific reagent injection rates and is based on boiler load since those loads have been correlated to furnace temperatures. The controls are often interlocked for each specific system so that the SNCR system will not be allowed to operate until it reaches the defined minimum boiler load. Many systems are installed with a plant permissive signal that can use a minimum operating temperature as measured at the furnace exit to determine when the SNCR system can be put into operation.

When boiler load and temperature ranges change based on different coals, combustion controls or other operating conditions, the needed temperature window at a given boiler load point may change location, and may require re-optimization of the system, or a change to the control logic for system operation. High CO levels in the flue gas in the SNCR temperature range can have a significant effect on SNCR performance and can also impact the effective temperature range. Operation of the SNCR system outside the defined temperature range can lead to unreacted reagent in the flue gas, i.e. ammonia slip, which can be detrimental to downstream components including the air preheater, particulate control devices or FGD systems. On shutdown, the SNCR system controls are setup to prevent operation below the low boiler load/minimum operating temperature set point.

The actual low boiler load at which an SNCR system can operate varies from unit to unit based on furnace type and geometry, flue gas velocities, heat transfer rates and combustion conditions. SNCR operation at 25% MCR from a cold start condition may be affected by the economizer outlet temperatures. Low temperatures may affect allowable ammonia slip, which can in turn affect NO_x reduction levels. Typically, reagent can be injected when the boiler load is at 30% MCR, although some operators do not often go lower than 40% MCR. Additional injectors can be added to allow operation at 30% Maximum Continuous Rate (MCR).

5.3 SCR

In many cases, the SCR is a strategic component of the mercury control system because it oxidizes elemental mercury in the flue gas for subsequent capture by carbon and/or an FGD. Better mercury oxidation is achieved without NH₃ being injected into the SCR. Therefore, for the purposes of Hg capture the SCR is engaged by not being bypassed. In EPA's background document (Ref. 3) they specifically address SCR startup for NO_x control. It appears that EPA intends to control NO_x during startup and shutdown but further clarification is required.

One significant factor to consider is that most newer coal fired plants as well as most retrofitted plants going back to year 2000 are inline systems with no flue gas bypass for startup or shutdown. Therefore, the flue gas must flow through the entire air pollution control train at all times. The inline systems bring certain startup operating issues with them along with certain environmental benefits. A fraction of SCR retrofit projects built between 2000 and 2005 did have bypasses built into the systems so that they could operate only during the ozone season. The operation of these bypasses can impact mercury emissions, as noted above, and may protect certain APC equipment. For example, if oil is used as the startup fuel, a buildup of oil soot can be deposited in the SCR and catalyst which can result in fires.

SCR systems cannot function to reduce NO_x until a minimum flue gas temperature is reached, at which time ammonia can be injected into the reactor vessel. As a rule of thumb, ammonia can only be injected

when the flue gas temperature is greater than approximately 600°F. The actual temperature when ammonia can be injected varies and is driven by flue gas sulfur trioxide (SO₃) concentration and flue gas moisture content. If ammonia is injected before the critical design temperature, as specified by the SCR catalyst manufacturer, is reached, ammonium bisulfate (ABS) is formed in the catalyst pores reducing the catalyst's ability to remove NO_x. Shutdown must also follow the same critical temperature shut off of ammonia. Catalyst suppliers are providing technology to expand this operating temperature range, however, limits still will apply. Some flexibility to operate briefly below the minimum operating temperature may be allowed by the catalyst supplier depending on operating conditions. This possibility must be discussed with the specific catalyst supplier. In addition, below minimum operating temperature, unreacted ammonia may exit the SCR reactor and react with SO₃ in the flue gas to form ABS in the air preheater downstream of an SCR, increasing pressure drop, reducing heat transfer effectiveness and resulting in higher maintenance costs. Formation of ABS is a concern for bituminous-fired boilers, which can have relatively high concentrations of SO₃ in the flue gas entering the air preheater. For western, low-sulfur coals, this is not as much of a concern.

Figure 1 showed typical startup times for a coal fired plant for warm and cold startups as described above. In the "warm" startup, the plant had been out of service for about one day and the boiler was kept warm. In this case the SCR can be brought into service about 15 hours after initial firing of the startup fuel. Figure 2 showed the same "warm" startup data along with generator load and fuel fired. It showed the SCR could be brought in service about three hours after the unit was on coal-only, exceeding the six hours after the start of electricity generation. In some cases, even with a warm startup, it is not certain that the SCR can be placed into service to begin controlling NO_x emissions during the startup period.

Cold startup data available from plants taken after a long outage show critical flue gas temperature is not reached in the SCR for 60 to 90 hours after initial startup on auxiliary fuel. This condition is at 60% load which is long after the plant has changed to coal firing and the plant is connected to the grid. In the example given in Figure 3, an SCR could not be brought into service until approximately 93 hours after initial oil firing.

Figure 5 shows examples of temperature profiles at an SCR reactor on a coal fired plant during a normal shutdown period followed by a warm startup. It also shows that from hours 9 to 18 the unit exceeded its permit level of 0.05 lb/MMBtu.

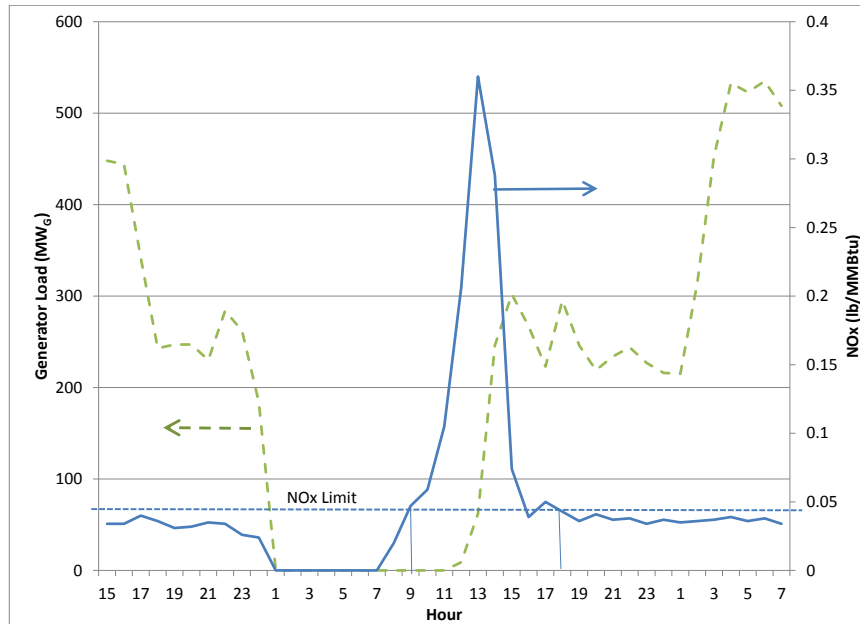


Figure 5. Example of load and stack NOx emissions during shutdown followed by warm startup.

There are alternate technologies that can be added to many coal fired plants that have SCR technology that can reduce the time it takes to reach the critical temperature including adding economizer bypass. Two types of bypass in the economizer section of the boiler can be employed that will increase the temperature at the SCR reactor so that the critical temperature required for ammonia injection is reached at 30% to 40% of the load. One technology is “hot water” bypass where part of the economizer is not used or feedwater heaters are bypassed to increase the water temperature going to the economizer which in turn increases the flue gas temperature entering the SCR reactor. Not every boiler can be modified to use this technology and there is a decrease in the boiler efficiency as well as an increase in the capital cost associated with the additional controls and piping required.

The second bypass technology uses flue gas taken from the boiler as it is entering the economizer section, where the gas temperature is greater than 800°F, and mixes it with the flue gas exiting the economizer section to increase the flue gas temperature in the SCR reactor. This approach can be used on most boilers but again it does reduce the boiler efficiency while in operation and incurs a capital cost.

Alternative boiler combustion modifications can be implemented to minimize NOx production until the SCR can be placed into operation. Overfire air and/or low NOx burners can be utilized to minimize NOx emissions during startup and shutdown operation. This requires a capital expenditure and the impact on boiler efficiency is dependent on system design and fuel burned.

A few plants are injecting a sorbent upstream of an SCR to capture SO₃. Reduction of flue gas SO₃ concentration upstream of the SCR allows a lower minimum operating temperature, as noted above. Such sorbents are either sodium or calcium based. Sodium is an SCR catalyst poison if condensation occurs at the catalyst (water soluble poison). Calcium-based sorbents may contribute to the formation of gypsum on the surface of the catalyst, which masks the active sites. Effects can be mitigated during shutdown by allowing flue gas to flow through the SCR reactor for some minutes after cessation of sorbent injection so the fly ash that remains on the catalyst after shutdown contains less sodium or calcium. Sorbent injection upstream of catalyst may shorten the catalyst life. Such effects may be reversible through catalyst regeneration. Impacts should be discussed with the catalyst supplier before

implementing upstream sorbent injection or increasing sorbent flow. Note that such effects may be incremental and shortening of catalyst life may be the best solution to meet a plant’s environmental compliance goals after all options have been evaluated.

5.4 Dry Sorbent Injection for Acid Gas Control

If DSI is the primary method for HCl removal, it should be started once minimum flow and temperature requirements are met, and operated on a predetermined load related curve. The effectiveness of the DSI system to maintain emissions is dependent on flow distribution and operating temperature range. Depending on different original equipment manufacturer (OEM) designs and specification requirements, minimum flue gas flow normally required to keep the injected sorbent (calcium/sodium or carbon) in suspension and off the duct floor would be about 50% of the design flow. However, flue gas mixing can be utilized to keep sorbent suspended at 25% design flow. Sodium sorbents require a minimum temperature to be effective including trona, which requires flue gas temperature to be greater than 290°F.

DSI can have beneficial uses during startup, shutdown, and cycling load periods. One benefit is that DSI can reduce corrosion that will occur during low load conditions. A second benefit is that DSI can be used to reduce the operating temperature when SCRs can begin injecting NH₃ and begin reducing NO_x. Finally, DSI can be used as a tool to reduce maintenance periods, especially with regard to air preheater cleanliness by reducing ABS formation.

During startup periods, SO₃ or sulfuric acid emissions are present, particularly when medium- to high-sulfur bituminous coals are fired. Expected sulfuric acid dew point temperatures for various types of coals are shown in **Error! Reference source not found.**

Coal Type	Sub-bituminous	North Dakota Lignite	Texas Lignite	Eastern Bituminous
Coal Sulfur, wt%	0.3-0.5	0.94	3.2	3.4
Coal Moisture, wt%	29	32	33	5
Sulfuric Acid Dewpoint, °F				
Without SCR	276-286	299	326	309
With SCR	289-299	312	340	323

Table 1. Expected Sulfuric Acid Dew point Temperatures for Several Types of Coal (Data Supplied by AEP).

As seen in the examples above, with an SCR system in service, the sulfuric acid dew point can increase from 10° to 20°F depending on the SO₂ to SO₃ conversion in the SCR.

As shown in Figure 6, sulfuric acid dew point temperature increases with SO₃ concentration and, at a fixed SO₃ concentration, increases with flue gas moisture content. SO₃, formed in the boiler from conversion of SO₂, reacts with moisture to become sulfuric acid vapor (H₂SO₄). Condensation to liquid

sulfuric acid occurs below the acid dew point temperature. The variation of the acid dew point temperature as a function of SO₃ concentration and moisture content is shown on the graph below. With an SCR system in service, the sulfuric acid dew point can increase from 10° to 20°F depending on the SO₂ to SO₃ conversion in the SCR.

During shutdown periods, the conveying air in the DSI lances should be left on to prevent plugging of the lances by fly ash. For the same reason, during startup, conveying air should be used, even if sorbent is not being injected.

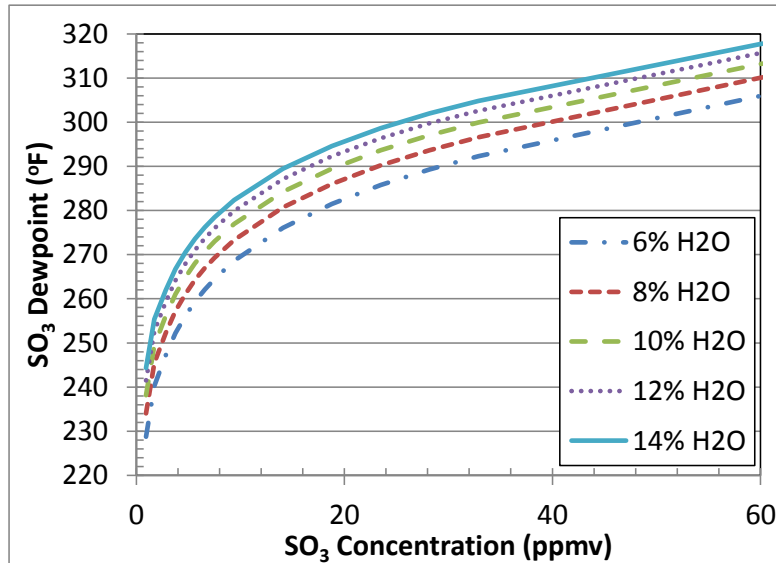


Figure 6. Sulfuric acid dew point curves (Ref. 7).

5.5 Sorbent Injection for Mercury Control

There are currently two predominant forms of injected sorbent mercury control agents, powdered activated carbon (PAC) which is available in both brominated and non-brominated forms and non-carbon based powdered reagents. Both alternatives are discussed below.

Powdered mercury control sorbents are injected using conveying air into power plant flue gas ductwork. Injection points range from upstream of the air preheater to downstream of a primary particulate collector or upstream of a scrubber. The material is conveyed from its storage point through piping or tubing to a series of lances that distributes the material into the flue gas stream. A separate ICAC white paper entitled “*Process Implementation Guidance for Powdered Sorbents at Electric Generating Units*”⁸ was published in February 2015 and is available for further details on delivery, storage, handling, injection, and safety of these materials.

Upon startup or shutdown of a unit, before beginning duct injection of a powdered sorbent material or in determining when to cease injection, certain conditions should be met. Suppliers and manufacturers provide recommendations on procedures, and may need to be consulted for the final configuration and process operation related to their materials. A brief list of relevant parameters includes:

- Carrying Velocity
 - Determine whether there is sufficient carrying velocity to convey the material in the duct without significant fallout. This will depend on the sorbent characteristics,

including particle size range, of the material itself as well as in-duct flue gas conditions. For carbon sorbents, typically the minimum conveying velocity for dilute phase flow is 2000-2400 ft/min.⁹

- Condensation
 - The moisture content of the flue gas creates a potential for condensation in equipment, resulting in pluggage if sorbent is turned on prematurely. The equipment temperatures need to be high enough during injection to avoid condensation.
- Open flow path
 - Check tubing/piping and lances for pluggage and make sure they are clear.
- Particulate collector operation
 - Sorbents are collected in either the primary particulate collector or a scrubber. These emission control devices should be operating normally when injecting a powdered material.
- Safety
 - PAC injection rates either should be scaled down during low flow conditions appropriate to maintaining a ratio of carbon to ash that is consistent with normal operation, or appropriate hopper management procedures should be developed for the unit if the amount of unburned carbon in the collected ash in a PM device collection hopper exceeds about 25% (see ICAC process whitepaper⁸ as well as ICAC whitepaper “ Design and Operation of Fabric Filter and Electrostatic Precipitator Hoppers with High-Carbon Ash”¹⁰). A safety advantage that the non-carbon based reagent provides is that it is not as combustible. Therefore issues such as dust explosions, fires, and self-heating are less likely.⁸
- Follow startup procedures
 - Warm-up time, blower operation with air prior to introducing sorbents and after ceasing injection, and proper system monitoring for pressure drop/flow or pluggages can prevent issues from developing.

5.6 ESP

Some State permits require ESPs to be in operation when firing any fuel or when the fans are in service. Some of the comments in this section are directed to operators as precautions during startup and shutdown conditions.

Flue gas temperature has a major effect on ESP operation and its mechanical and electrical integrity. For example, if the ESP high voltage power supplies are energized prior to the flue gas being above the acid dew point temperature, there is a high probability that wet ash particles will be collected on the emitting and collecting electrodes and hopper walls which is extremely difficult to remove with electrode rapping. When this material is subsequently dried upon reaching normal operating temperatures, the material can form hard crusty deposit firmly cemented to the ESP electrodes. With the ‘fouling’ of the electrodes, ESP collection efficiency will be reduced to a degree depending on the amount of ash buildup. Another aspect of ESP startup includes potential spikes in particulate matter due to a variety of causes. Buildup of ash in duct work after an emergency shutdown or boiler trip, as well as high levels of upstream sorbent injection, can lead to spikes in PM readings prior to the ESP being fully operational.

Boiler startup and shutdown is a critical period for the operation of an electrostatic precipitator (ESP) that can have a direct impact on the ESP achieving its design performance and maintaining this performance. The two main concerns for startup and shutdown are the flue gas temperature as related

to operation of the ESP below the acid dew point and the potential for spontaneous combustion or explosion with existence of unburned combustibles in the flue gas which could be ignited by sparking in the ESP.

During boiler start and warm-up, there is the potential for excessive production of carbonaceous material, CO or unburned fuel caused by incomplete combustion. This can create a hazardous condition that could cause conditions for spontaneous combustion or even explosion particularly if there is sparking in the ESP with the ESP energized. This is also a period when excessive oxygen is passing through the system which compounds or accentuates this condition.

Carbon monoxide is extremely unstable so that general flammability limits are considered as explosion limits. The lower explosion limit (LEL) is the concentration below which a flame will not propagate due to a limited quantity of combustible material. Safety restrictions require that the combustible gas be one-fourth of the LEL. The LEL is computed using an adiabatic combustion calculation and is computed for pure carbon monoxide in air.

Excessive carbonaceous ash (high loss on ignition or LOI) production can lead to a fire of the dust collected on the ESP collecting plates and/or ESP hoppers when excessive oxygen levels are present in the flue gas during boiler startup. Carbon build up in the ash can also occur where high levels of activated carbon injection are taking place for mercury control. As with excess CO in the flue gas previously discussed, the ignition source in the ESP is sparking between electrodes. Boiler startup is a period characterized by rapid transient changes in flue gas conditions which includes oxygen levels. Applications with a higher probability of fires include wood waste boilers, oil fired boilers and coal stoker fired boilers.

Although a minimum temperature of 250°F is recommended to achieve the best performance, maintain reliability and mitigate spontaneous combustion risks, MATS compliance may dictate whether the ESP must be operational and energized prior to reaching this temperature. This requirement will depend on what fuels are being fired and start up type as described in Section 2.2 for an individual site's specific scenario.

5.7 Baghouse

With a baghouse (also called a fabric filter) in operation, low flue gas temperatures result in moisture and damp ash collecting on the filter bags causing an increase in filter cake drag and decrease in cake permeability. If low temperature operation occurs for an extended period of time, there is the risk of permanently blinding the bags. Acid condensation with operation below the acid dew point can lead to premature filter bag failure.

These conditions can be greatly alleviated by the use of pre-coat of the filter bags and/or a sacrificial chamber on *initial* startup. Bags may be pre-coated with sorbent from an upstream DSI or CDS system or per supplier's recommendation. Precoating with a lime-based sorbent can be a problem for a TOXECON™ fabric filter in bituminous coal (where HCl and SO₃ may be high). The pressure drop can creep up due to moisture formation (from calcium chloride and sulfuric acid) since TOXECON has little fly ash present. For existing bags, best practice is to not remove all the ash before shutdown so there is a protective layer existing for the following startup.

The baghouse for particulate removal does not have any minimum flow or temperature requirements prior to operation to minimize the number of bags that may be weakened by operation below the acid dew point. Specific manufacturers may limit the number of compartments in service at reduced temperatures. The bags have a maximum continuous temperature limit dependent on the filter bag medium (~375°F for PPS, the material most commonly used).

Some plants have observed mercury re-emissions from the filter bags during transient conditions such as startup. This phenomenon has not been well characterized to date, but it is possible that early injection of PAC might be required during startup.

5.8 DFGD

For an integrated system of a fabric filter with a spray dryer absorber (SDA) upstream, the potential for acid condensation in the fabric filter can be greatly reduced with the startup procedure requiring the spray dryer be in operation at the same time as the fabric filter. However, if the temperature of the flue gas is too low entering the spray dryer, lime slurry may not dry fully in the absorber and will coat the walls of the absorber vessel and allow carryover of moist reagent and ash into the fabric filter with the potential of blinding the filter bags. Thus, as discussed previously, it is important to develop startup and shutdown procedures for multiple installed APC systems treated as an integrated system with not only the boiler flue gas characteristics in mind but also the effect on APC equipment operation upstream of each APC system.

DFGD systems can be put into two general categories; spray dryer absorbers and circulating dry scrubbers. For the purpose of this discussion, NID system is grouped with CDS as the technology and operating conditions are similar. Both SDA and CDS systems have a common design feature – both have an absorber vessel followed by in most plants a baghouse. An SDA injects lime slurry into the absorber while the CDS uses a dry hydrated lime sorbent and separate water injection. This difference results in different startup conditions for these two systems. Neither system can be operated with slurry or water addition at low temperatures because of the potential for corrosion in the ductwork and baghouse. Generally, these systems are operated at a 30-40°F approach temperature to saturation.

In an SDA system since a wet lime slurry is being injected a minimum flue gas flow and temperature has to be maintained, if not the lime slurry will build up on the walls of the absorber vessel which can cause structural damage or pluggage in the vessel. Normally operators do not turn on their SDA lime slurry unit they have a minimum of 250°F and require 50% of design flow. During normal startup operators do experience some SO₂, SO₃, HCl, and Hg removal due to some residual lime coating the bags in the baghouse. Particulate removal can be maintained during startup and shutdown operating periods.

A CDS system can be operated in a different mode than an SDA. In a CDS lime can be injected during startup as soon as the lime can be suspended in the absorber vessel. Hydrated lime will remove some SO₂ even without water injection. Water for cooling and assisting the lime in absorbing SO₂ can be injected when the flue gas reaches 180°F dependent on flue gas properties. Depending on different OEM designs and specification requirements, flue gas flow normally required to support a bed would be about 50% of the design flow. However, flue gas recirculation can be utilized to reduce the boiler flow to 25% or lower. Utilizing flue gas recirculation at reduced loads may restrict how much water can be added to the system as the combined flue gas temperature to the CDS decreases when mixed with the cooler recirculation gas.

5.9 WFGD

Most WFGD systems use recycle spray systems using headers and nozzles to cool the flue gas and to remove acid gases by contacting a sorbent slurry with the flue gas. Most WFGDs have between three to six independent spray header systems and have either fiberglass or plastic components integral to the system. The plastic or fiberglass has to be protected against high gas temperatures (~220°F for FRP, dependent on supplier). One or two of the lower spray headers needs to be turned on once the FGD system manufacture’s maximum temperature guideline is reached regardless if the auxiliary fuel or coal is being burned. Flaked glass-lined systems often require a recycle pump in service prior to the introduction of flue gas. A minimum number of recycle pumps should be placed in service at low load conditions to protect the system against a down draft of slurry. Generally, a recycle pump is placed in service when induced draft (ID) fans are placed in service and reagent addition placed in automatic mode. If the absorber inlet is not properly designed, the downdraft may result in slurry carryover into the inlet ductwork causing buildup.

Operating units with WFGD systems are capable of maintaining SO₂ emissions during startup and shutdown operating periods.

6 Summary

Typical Startup Procedures:

APC Equipment	Warm Startup	Cold Startup
SCR	Require minimum temperature (independent of load or duration) prior to ammonia injection.	Require minimum temperature (independent of load or duration) prior to ammonia injection, but should be inline no later than first fire of Hg containing fuel.
SNCR	Require minimum temperature (independent of load or duration) prior to ammonia injection.	Require minimum temperature (independent of load or duration) prior to ammonia injection.
Wet FGD	No minimum requirements prior to startup	No minimum requirements prior to startup.
Spray dryer/baghouse	Require minimum temperature and flue gas flow prior to lime slurry spray. Some emission reductions can be maintained by the baghouse dustcake prior to slurry injection.	Require minimum temperature and flue gas flow prior to slurry spray. Some emissions can be maintained with baghouse prior to slurry injection.
CDS/baghouse	Require minimum flue gas flow prior to lime injection and require minimum temperature prior to water spray. Some emission reductions can be maintained by the baghouse dustcake prior to additional lime and water injection.	Require minimum flue gas flow prior to lime injection and require minimum temperature prior to water spray. Some emission reductions can be maintained by the baghouse dustcake prior to additional lime and water injection.
DSI or carbon injection system	Require minimum flue gas flow prior to sorbent injection.	Require minimum flue gas flow prior to sorbent injection.

	Sodium sorbent systems require minimum temperature. Conveying air should flow through lances to prevent plugging by fly ash.	Sodium sorbent systems require minimum temperature. Conveying air should flow through lances to prevent plugging by fly ash.
Baghouse	Do not pulse off all the ash before shutdown so there is a protective layer existing for the following startup.	Do not pulse off all the ash before shutdown so there is a protective layer existing for the following startup.
ESP	Energize when flue gas temperature >250°F.	Energize when flue gas temperature >250°F.

Typical Shutdown Procedures:

APC Equipment	Normal Shutdown
SCR	Discontinue ammonia feed at minimum temperature.
SNCR	Discontinue ammonia feed at minimum temperature.
Wet FGD	System can remain in service during shutdown. The number of recycle pumps in service should be limited to minimize blow back into inlet ductwork at reduced flow.
Spray dryer/baghouse	Discontinue lime slurry feed at minimum temperature and flue gas flow.
CDS/baghouse	Discontinue water feed at minimum temperature and discontinue lime feed at minimum flue gas flow.
DSI or carbon injection system	Discontinue sorbent feed at minimum flue gas flow. Discontinue sodium sorbent feeding system at minimum temperature.
Baghouse	System can remain in service during shutdown. May have to place compartments out of service based on flow and or temperature dependent on manufacturers recommendations. Do not pulse off all the ash before shutdown so there is a protective layer existing for the following startup
ESP	System can remain in service during shutdown until flue gas temperature is reduced to 250 °F.

Dependent on the APC equipment installed and permit requirements, each plant requires a review to define startup and shutdown operating conditions and determine if improvements can be made to the existing design to minimize emissions during startups and shutdowns.

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8 List of Acronyms and Abbreviations

ABS	Ammonium Bisulfate
ACI	Activated Carbon Injection
AEP	American Electric Power
APC	Air Pollution Control
APCD	Air Pollution Control Device
CAA	Clean Air Act
CAMD	Clear Air Markets Database
DAS	Data Acquisition System
CDS	Circulating Dry Scrubber
CEMS	Continuous Emission Monitoring System
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CO ₂	Carbon Dioxide
DFGD	Dry Flue Gas Desulfurization
DRE	Destruction Removal Efficiency
DSI	Dry Sorbent Injection
EGU	Electricity Generating Unit
EPA	Environmental Protection Agency
ESP	Electrostatic Precipitator
FD	Forced Draft
FF	Fabric Filter
FGD	Flue Gas Desulfurization
FRP	Fiberglass Reinforced Plastic
FTIR	Fourier Transform Infrared Spectroscopy
GHG	Greenhouse Gases
H ₂ SO ₄	Sulfuric Acid
HAP	Hazardous Air Pollutants
HCl	Hydrogen Chloride
Hg	Mercury
IB	Industrial Boiler
ICAC	Institute of Clean Air Companies
ID	Induced Draft
IGCC	Integrated Gasification Combined Cycle
lb/MMBtu	Pounds Per Million (10 ⁶) British Thermal Unit
lb/TBtu	Pounds Per Trillion (10 ¹²) British Thermal Unit
LEL	Low Explosive Limit
LNB	Low NO _x Burner
LOI	Loss on Ignition
MACT	Maximum Achievable Control Technology
MATS	Mercury and Air Toxics Standards
MCR	Maximum Continuous Rating
MW	Megawatt
NESHAP	National Emission Standards for Hazardous Air Pollutants
NFPA	National Fire Protection Association
NH ₃	Ammonia
NID	Novel Integrated Desulfurization

NO _x	Nitrogen Oxides
NSPS	New Source Performance Standard
O ₂	Oxygen
OEM	Original Equipment Manufacturer
OFA	Overfire Air
PAC	Powdered Activated Carbon
PM	Particulate Matter
ppm	Part Per Million
ppmv	Part Per Million by Volume
QA/QC	Quality Assurance/Quality Control
RATA	Relative Accuracy Test Analysis
SBS	Sodium Bisulfate
SCR	Selective Catalytic Reduction
SDA	Spray Dryer Absorber
SNCR	Selective Non-Catalytic Reduction
SO ₂	Sulfur Dioxide
SO ₃	Sulfur Trioxide
VOC	Volatile organic compound
WFGD	Wet flue-gas desulfurization
wscf	Wet Standard Cubic Feet (at 68°F and 29.2 in-Hg)
µg	microgram