INSTITUTE OF CLEAN AIR COMPANIES

August 26, 2013

Air and Radiation Docket
Environmental Protection Agency
Mailcode: 2822T,
1200 Pennsylvania Ave., NW
Washington, DC 20460

Re: Docket ID. EPA-HQ-OAR-2011-0044 (NSPS action) and Docket ID & EPA-HQ-OAR-2009-0234 (NESHAP/MATS action)

The Institute of Clean Air Companies (ICAC) appreciates the opportunity to comment on the U.S. Environmental Protection Agency's (EPA's) proposed Reconsideration of Certain Startup/ Shutdown Issues. 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 nearly 100 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 (NOx), hazardous air pollutants (HAP), and greenhouse gases (GHG). Comments pertaining to a number of issues regarding the proposed reconsideration are provided below.

Overarching Comments

In reviewing the comments and regarding startup and shutdown there appears to be a lack of technical information regarding the engineering and science of air pollution control (APC) equipment. The impact on emissions and APC operations is not directly related to the use of startup fuels, steam flow, or synchronization to the grid. APC systems ability to function and operate is based on flue gas temperature and volume flow.

EPA's request for comments is based on the following points:

- The use of a default electrical production rate value to calculate output-based emission limits during startup and shutdown hours where the electrical load is zero. Could startup be defined at coal-fired EGUs as occurring at 25 percent of nameplate capacity plus 3 hours or the start of electricity generation plus 6 hours, whichever comes first;

- The use of default diluent gas cap values during periods of startup and shutdown; and
- How to calculate startup/shutdown emissions when multiple affected EGUs share a common stack. This write-up provides comments based on the existing technologies commonly used for pollution control.

ICAC's Recommendations for Startup and Shutdown Provisions for APC Equipment

Boiler startup and shutdown are critical periods for the operations of APC systems. We do not believe that there is a one set rule that can cover all the diverse designed power plants that exist today. There are some external issues that we not sure some people will recognize. Plants try to synch as fast as possible based on equipment constraints. Due to current grid stability, ISOs & transmission management have very strict requirements for ramp rates and synch schedules. The North American Electric Reliability Corporation (NERC) & the Federal Energy Regulatory Commission (FERC) are involved to ensure a stable grid, which has been exacerbated by renewable s and low dark spreads.

ICAC recommends a Work Practice Procedure to determine when startup and shutdown start the clock for compliance. Each plant is so unique that the process has to be designed for each plant. We understand that this makes enforcement more difficult for EPA, but we believe that a Work Practice process with guidelines can be developed by the power industry, EPA, the equipment manufactures, and the environmental community.

Periods of operation, especially for boiler startup, are characterized by rapid transient changes in flue gas composition, quantity, temperature, and moisture conditions. As discussed in the EPA training manuals for Fabric Filters and Electrostatic Precipitators in the section on startup and shutdown, improper startup and shutdown cannot 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.

The problems are aggravated with installation of multiple air pollution control (APC) equipment and processes, especially those required to achieve MATS compliance. There may be installed on a coal fired utility boiler, between boiler and stack, APC equipment to include SNCR, SCR, Dry sorbent injection (DSI), Powdered Activated Carbon (PAC), scrubber (circulating dry scrubber, spray dryer absorber, or wet FGD spray tower), plus particulate collectors to include an ESP, Fabric Filter or both. For startup and shutdown conditions, the APC equipment and systems cannot be viewed as single stand-alone entities anymore for startup and shutdown operating requirements 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.

For example, flue gas temperature has a major effect on APC equipment operation and mechanical component integrity during boiler startup and shutdown. With 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. Acid condensation with operation below the acid dewpoint can lead to premature filter bag failure. These conditions can be greatly alleviated by the use of pre-coat of the filter bags but, if low temperature operation occurs for an extended period of time, there is the risk of permanently blinding the bags.

For an integrated system of a fabric filter with a spray dryer absorber upstream, the potential for acid condensation in the fabric filter can be greatly reduced with the startup procedure requiring that 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.

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 dewpoint 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.

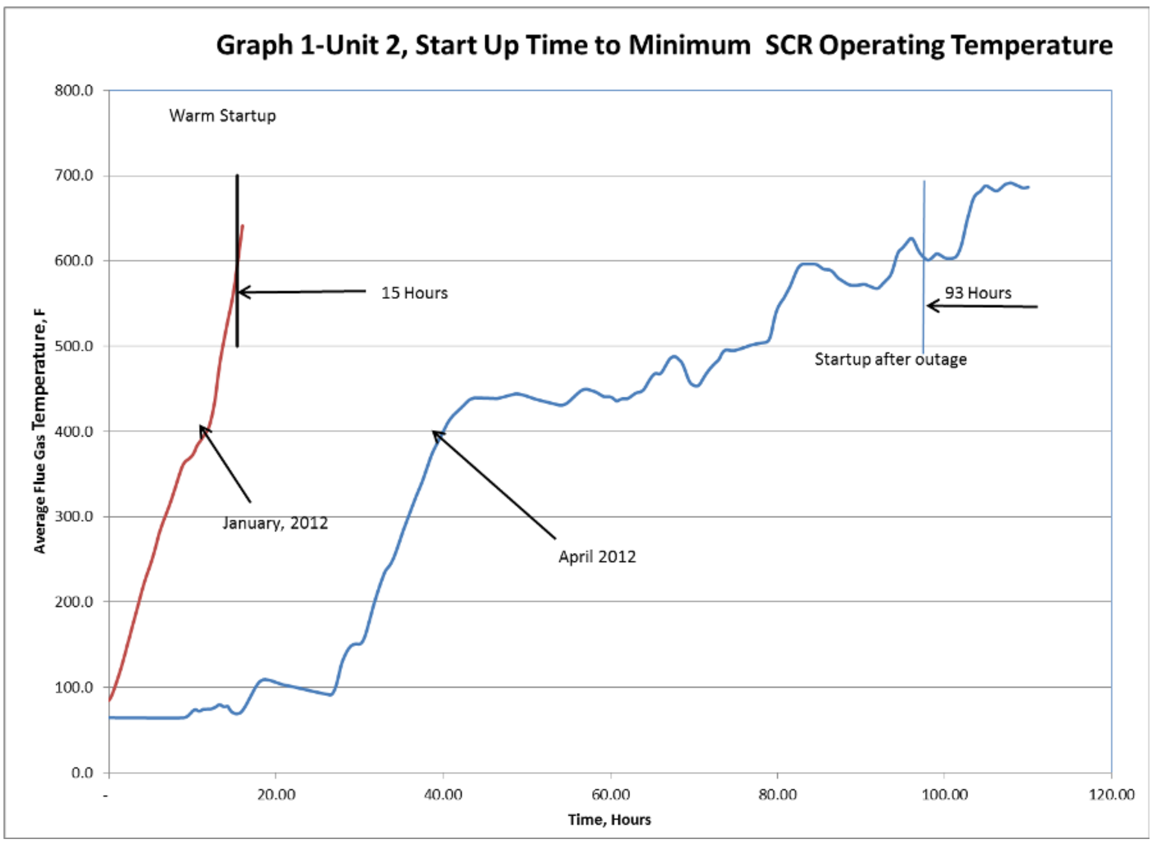
The problems discussed related to low flue gas temperature during boiler startup can also occur on boiler shutdown. Only a few examples have been presented of the performance degradation that can occur if particulate control equipment is started up prematurely and thus it is critical that proper startup 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.

Specific Comments

Controlling Emissions Rates During Startup and Shutdown

In general, there are two types of startups and shutdowns for coal fired plants we will address in this paper. These comments only address APC systems on coal-fired units. APC systems on simple cycle and combined cycle plants are not included in these comments.

Coal plants startups can be categorized as either a warm startup or a cold startup while shutdowns can be categorized as normal and emergency shutdown. The emissions and operating cycles are very different in the two startup conditions. A warm startup would be when a plant has come off line for a few hours or a day or two. Cold startups are generally when a unit has been offline for days such as when a unit has been offline for an annual outage. Graph 1 shows temperature profiles for at a reactor for an SCR on a 440 MW coal fired plant during warm startup and cold startup periods. The duration of the startup is dependent on the speed the system can be brought up in temperature without causing thermal stress.



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 startup to prevent thermal stresses to the system. The operator cannot put load on the generator until the unit is synced to the grid. So as soon as there is load on the generator (for example, >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 usually no more than 20 minutes after syncing. Other plants require higher loads before firing coal.

The startup fuel is continued until a certain number of mills are brought in service. At some plants the startup fuel is co-fired and continues till 1/2 load and at other facilities it continues till 2/3 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 temperature with clean burning startup fuel and to bring APC equipment into service prior to firing coal.

Startup Operating Conditions

The complicating factor is that SCRs, WFGD and DFGD can be operational at different times during the startup cycle. Each of these technologies design characteristics mandates different operating conditions that cannot be singularly defined that the entire plant has completed startup.

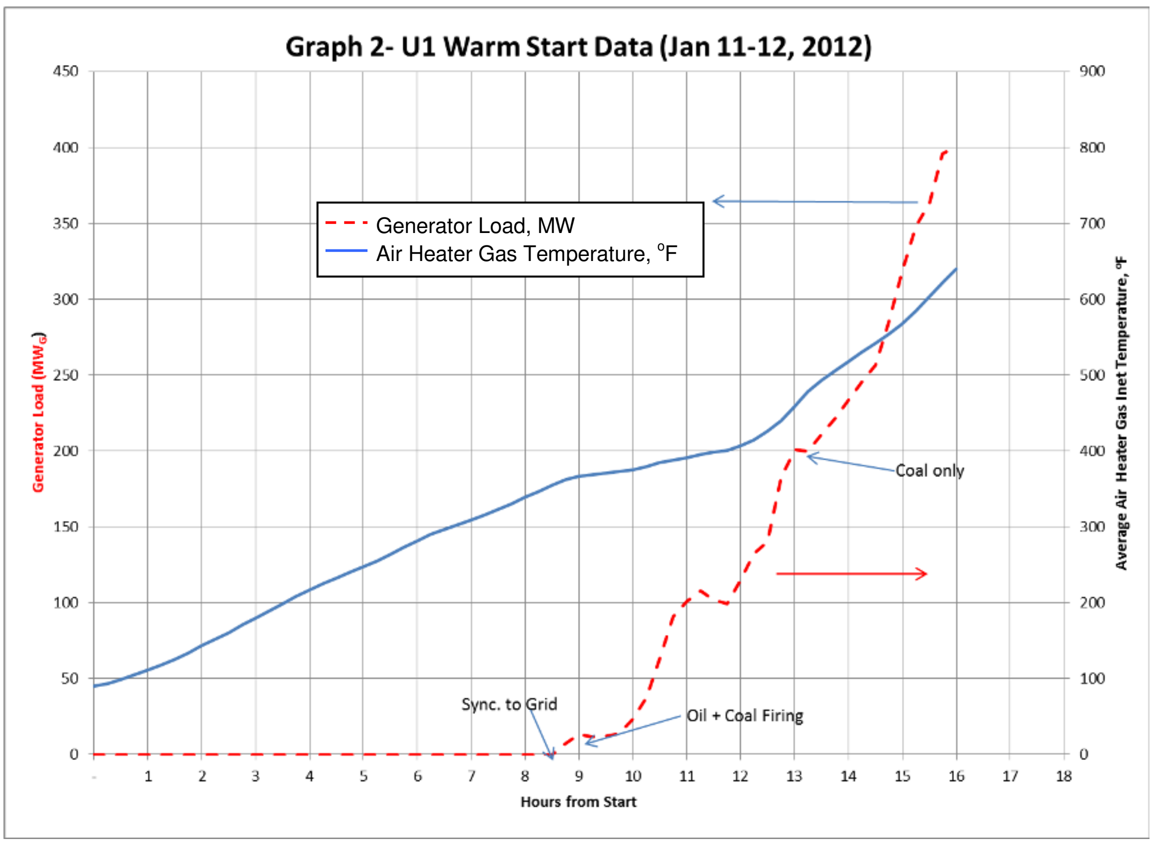
Selective Catalytic Reduction (SCR)

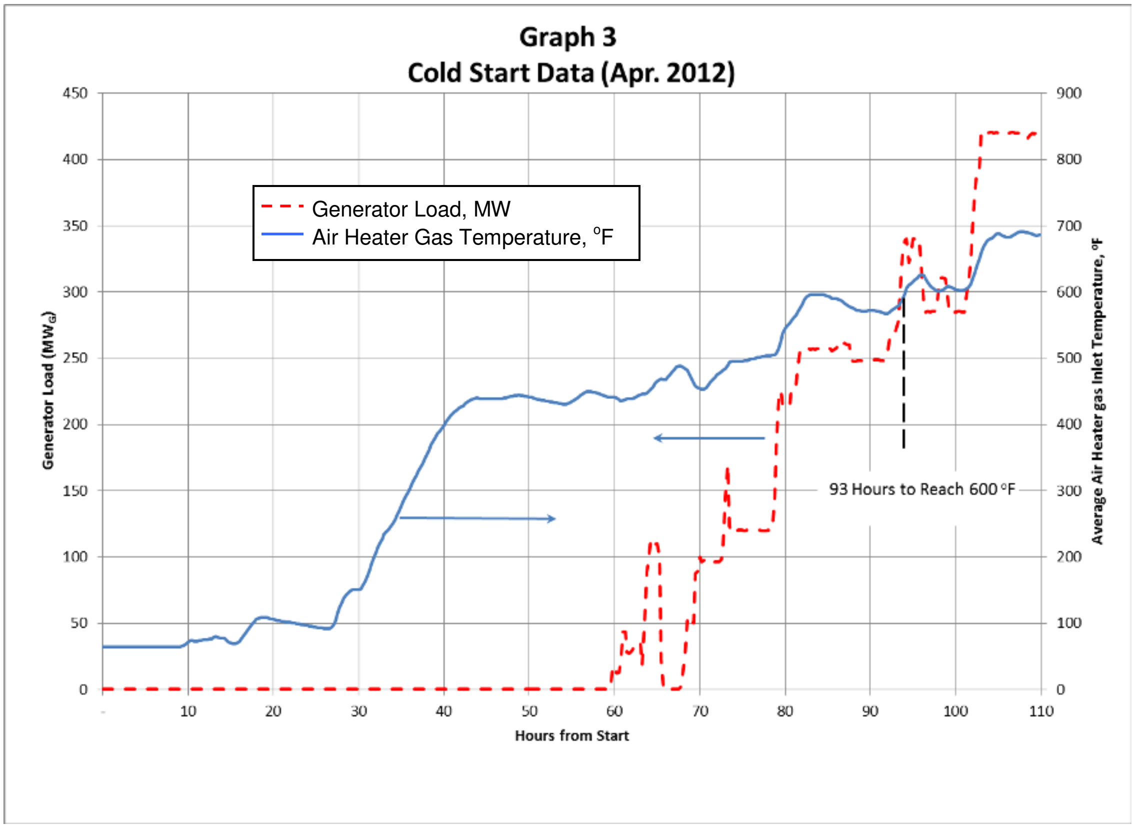
One significant factor to consider is that most of both the newer coal fired plants as well as most of the recent retrofitted plants going back to 2000 are inline systems with no bypass for startup or shutdown. Therefore, the flue gas must flow through the entire air pollution control train at all times. The inline systems bring certain startup operating issues with them along with certain environmental benefits. A fraction of SCRs 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 operations of these bypasses do not impact the startup and shutdown functions described in the MATs and MACT standards.

SCR systems cannot function, i.e. reduce NOx, until a minimum flue gas temperature is reached when ammonia is injected into the reactor vessel. As a rule of thumb, ammonia can only be injected when the flue gas is greater than approximately 600°F. The actual temperature when ammonia can be injected varies and is driven by the sulfur content of the fuel, flue gas moisture content and ammonia content. Catalyst formulation can also have some influence. If ammonia is injected before the critical design temperature, as specified by the SCR/catalyst manufacture, is reached, ammonium bisulfate is formed in the catalyst pores reducing the ability to remove NOx. 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.

Graph 1 shows 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 on the startup fuel or about 3 hours after the plant achieved 25% of its nameplate generation capacity. Graph 2 shows the same "warm" startup data along with generator load and fuel fired. It shows the SCR could be brought in service about 3 hours after the unit was on coal only exceeding the 6 hours after the start of electricity generation. This data shows that even with a warm startup, it is marginal that the SCR can be placed into service to begin controlling NOx emissions.

Cold startup data available from plants taken after a long outage show critical 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. As seen in Graph 3, an SCR could not be brought into service until approximately 93 hours after initial oil firing or approximately 13 hours after achieving 25% of the nameplate capacity.





There are alternate technologies that can be added to "most" coal fired plants using 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 SCR vessel so that the critical temperature required for ammonia injection is reached at 30 to 40% of the load. One technology is "hot water" bypass. Part of the economizer is not used or feedwater heaters are bypassed to increase the water temperature going to the economizer which increases the flue gas temperature going to the SCR reactor. Not every boiler can be modified to use this technology, and there is a decrease in the boiler efficiency and added capital cost associated with the additional controls and piping required.

The second bypass technology uses flue gas taken from the boiler entering the economizer section where the gas temperature is 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 completed 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.

Selective Non-Catalytic Reduction (SNCR)
Selective non-catalytic reduction (SNCR) is a post-combustion NOx reduction method that reduces NOx through a controlled injection of ammonia or urea into the combustion gas path at a specific reaction temperature range.

SNCR systems reduce NOx when ammonia is injected at flue gas temperatures between 1600°F and 1800°F, and urea is injected when temperatures are between 1800°F and 2000°F. Injection at temperatures below these ranges can result in unreacted ammonia to slip through the boiler, and injection at higher temperatures will produce less efficient NOx reduction.

SNCR systems are designed based on each customer's specific requirements including the load range over which the system will operate. Effective SNCR operation is based on injection of the reagent into the temperature windows described above to reduce NOx emissions. Systems typically use boiler load as the control parameter since it is correlated with the proper temperature range. Systems commonly have multiple levels of injectors, and injectors are turned on or off based on the furnace temperatures. The proper temperature window will be at a higher elevation in the furnace at 100% MCR, and the proper temperature zone for injection will be at lower elevations in the furnace at lower boiler loads. Each system is specifically designed for a specific minimum boiler load operating condition. Some systems only utilize one level of injectors and are limited to a narrow operating boiler load range which normally would include the 100% MCR condition.

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 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 temperature window at a given boiler load point may change, and may require re-optimization of the system, or a change to the control logic for system operation. High carbon monoxide (CO) levels in the flue gas in the SNCR temperature range can have a significant effect on SNCR performance and also can affect the effective temperature range. Operation of the SNCR system outside the defined temperature range can lead to unreacted reagent in the form of 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.

In the EPA comments, 25% MCR has been referenced as the defined boiler load at which SNCR operation can begin. However, this load may not provide sufficient temperature for SNCR operation. The actual low boiler load at which an SNCR system can operate varies from unit to unit based on furnace type, geometry, flue gas velocities, heat transfer rates and combustion conditions. It is important to note that 25% of MCR is not a typical low boiler load at which SNCR injection is effective in reducing NOx emissions. The range is often 30 to 40% of MCR, but even that is unit specific and is based on furnace temperatures along with the number and location of injection levels. Furnace temperature is the key parameter and boiler load is only applicable in terms of how it relates to the furnace temperatures.

Wet Flue Gas Desulfurization (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 ID fans are placed in service and reagent addition placed in automatic. 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 SO_2 emissions during startup and shutdown operating periods.

Dry Flue Gas Desulfurization (DFGD)

DFGD systems can be put into two general categories Spray Dryer Absorbers (SDA) and Circulating Dry Scrubbers (CDS). For the purpose of this discussion, NIDS is grouped with CDS as the technology and operating conditions is 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 control at a 30-40^{o}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 SO_2, SO_3, HCl, and Hg removal due to 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 SO_2 even without water injection. Water for cooling and assisting the lime in absorbing SO_2 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 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.

Dry Sorbent or Carbon Injection (DSI)
The effectiveness of the DSI system to maintain emissions is dependent on flow distribution and operating temperature range. Depending on different OEM designs and specification requirements, flue gas flow normally required to support DSI and carbon injection systems would be about 50% of the design flow. However, flue gas mixing can be utilized to reduce the flow to 25%. Some sorbents require a minimum temperature to be effective including Trona that requires flue gas temperature to be greater than 290^{o}F. SBS injection requires flue gas temperature to be greater than 250^{o}F.

Activated carbons however will generally perform better at lower temperatures. Ultimately, the determining factor of when to turn carbon injection on or off may often be the operational constraints of the injection system designed to handle it. Currently, there is likely to be very little data on the performance of activated carbons during startup and shutdowns since many utilities choose to comply with sorbent traps and have not measured emissions during those periods.

During startup when fly ash is not present or in a Toxecon arrangement for example, then there is a risk of fire if the carbon is allowed to stand for long periods of time in a hot environment because oxidation reactions occur on the surface of activated carbon which generate small amounts of heat. If the carbon is very concentrated, and kept hot a long time (and carbon is a great insulator) enough heat can be built up to lead to smoldering occurring. Activated Carbon should not be injected in startup or shutdown conditions while oil firing.

Baghouse

The baghouse for particulate removal does not have any minimum flow or temperature requirements prior to operation. However, the bags require a pre-coating of material to protect the system from corrosive attack during startup. Bags may be pre-coated with sorbent from an upstream DSI or CDS system or per supplier's recommendation. Specific manufacturers may limit the number of compartments in service at reduced temperatures. The bags have a maximum continuous temperature limit ~375^{o}F dependent on the filter bag medium. A bypass system may be included to bypass the baghouse during high temperature excursions during which time particulate will not be removed from the system.

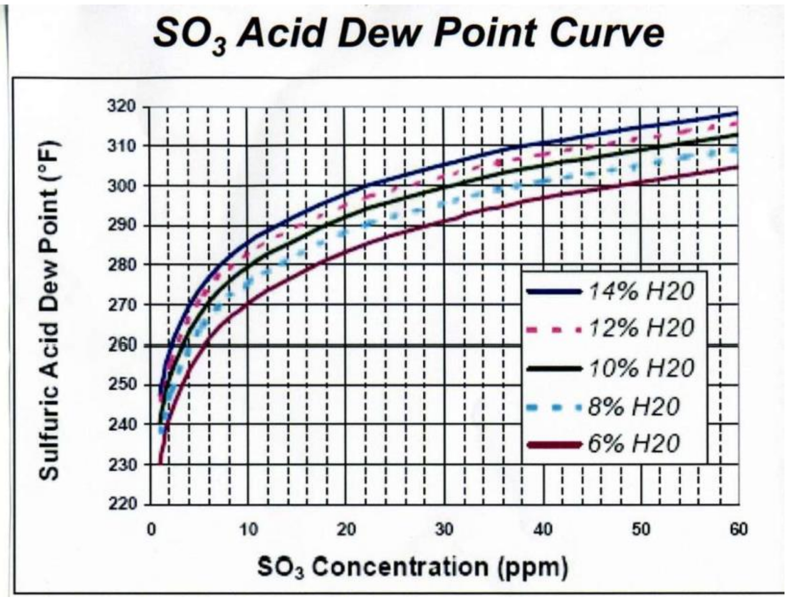
Electrostatic Precipitator (ESP)

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 dewpoint 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.

Acid Dewpoint Considerations

An ESP should not be energized until the flue gas temperature is above the acid dewpoint temperature. If the high voltage power supplies are energized prior to the flue gas being above the acid dewpoint temperature, there is a high probability that moist ash particles will be collected on the emitting and collecting electrodes and hopper walls forming a damp sludge that will be very difficult to remove. When this buildup of material is subsequently dried upon reaching normal operating temperatures, it can form hard crusty deposits firmly cemented to the ESP electrodes and hoppers which cannot be dislodged by rapping. This condition can cause prolonged operating problems with corona suppression and collecting plate buildup resulting in reduced performance of the unit. In addition, during startup, this damp ash can create a wet conductive coating on the surfaces of high voltage support and anti-sway insulators causing electrical tracking leading to short circuits and potential failure of the insulators.

Sulfuric acid dewpoint temperature increases with SO_3 concentration and, at a fixed SO_3 concentration, increases with flue gas moisture content. SO_3, formed in the boiler from conversion of SO2, reacts with moisture to become sulfuric acid vapor (H_2SO_4). Condensation to liquid sulfuric acid occurs below the acid dewpoint temperature. The variation of the acid dewpoint temperature as a function of SO3 concentration and moisture content is shown on the graph below.



Expected Sulfuric Acid Dewpoint Temperatures for Several Types of Coal (Data Supplied by AEP)

Coal Type	PRB	ND Lignite	TX Lignite	Eastern Bituminous
Coal Sulfur %	0.3-0.5	0.94	3.2	3.4
Coal Moisture %	29	32	33	5.0
Sulfuric Acid Dewpoint °F, w/o SCR	276-286	299	326	309
Sulfuric Acid Dewpoint °F, with SCR	289-299	312	340	323

As seen in the examples above, with an SCR system in service, the sulfuric acid dewpoint can increase from 10° to 20°F depending on the SO_2 to SO_3 conversion in the SCR.

Spontaneous Combustion or Explosion

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 accelerates this condition. To avoid these hazardous conditions, typically the ESP is not energized for a period of thirty (30) minutes after stable flame has been achieved.

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. The graph below shows the maximum carbon monoxide limit versus temperature for safe ESP operation. The curve is applicable for an oxygen content in the flue gas up to 13%.

Excessive carbonaceous ash (high 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. As with excess CO in the flue gas previously discussed, the ignition source in the ESP is sparking between electrodes. The graph below shows the oxygen levels required to support ash combustion versus flue gas temperature in the ESP. 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.

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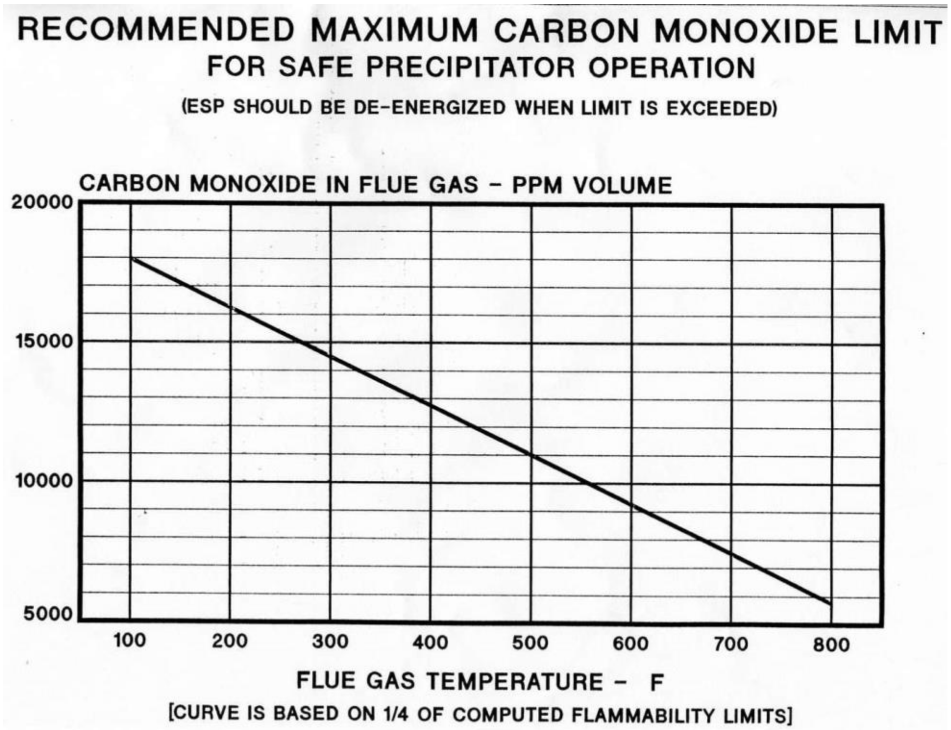
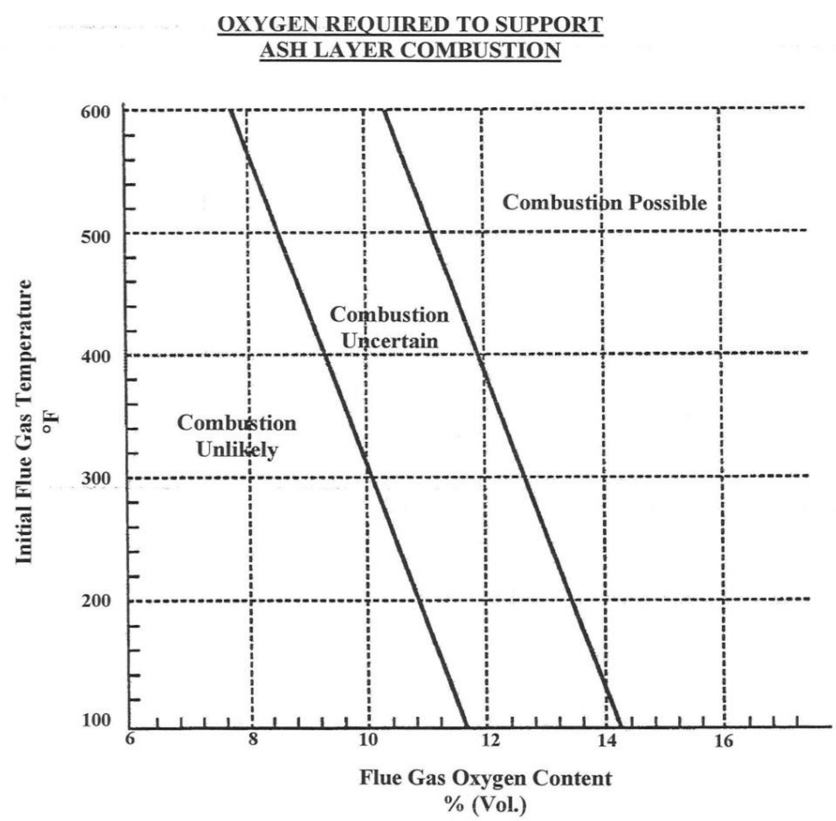

RECOMMENDED MAXIMUM CARBON MONOXIDE LIMIT
FOR SAFE PRECIPITATOR OPERATION
(ESP SHOULD BE DE-ENERGIZED WHEN LIMIT IS EXCEEDED)
CARBON MONOXIDE IN FLUE GAS - PPM VOLUME
20000
15000
10000
5000
100
200
300
400
500
600
700
800
FLUE GAS TEMPERATURE - F
[CURVE IS BASED ON 1/4 OF COMPUTED FLAMMABILITY LIMITS]


OXYGEN REQUIRED TO SUPPORT
ASH LAYER COMBUSTION
Combustion Possible
Combustion
Uncertain
Combustion
Unlikely
Initial Flue Gas Temperature
°F
600
500
400
300
200
100
6
8
10
12
14
16
Flue Gas Oxygen Content
% (Vol.)

Typical Startup Procedures:

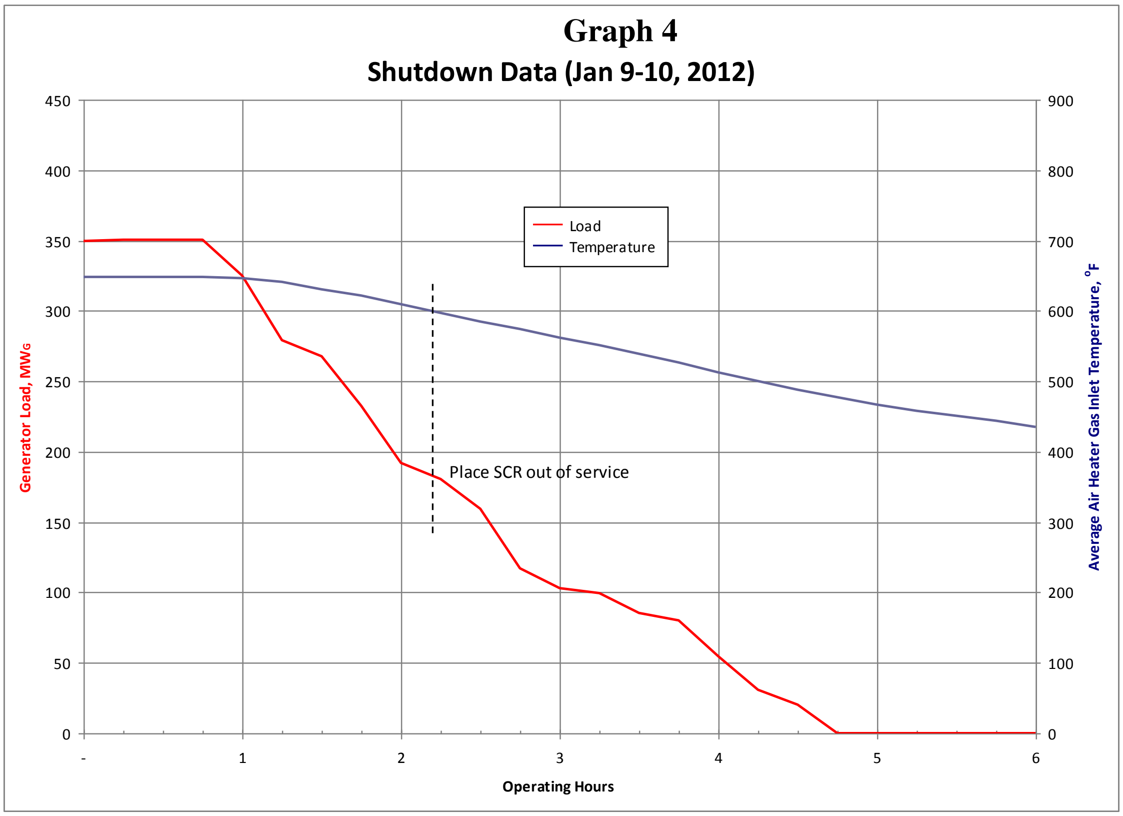
APC Equipment	Warm Startup	Cold Startup
SCR	Require minimum temperature (independent of load or duration) prior to ammonia injection	Require minimum temperature (independent of load or duration) prior to ammonia injection
SNCR	Require minimum temperature (independent of load or duration) prior to ammonia 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 emissions can be maintained with baghouse 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 emissions can be maintained with baghouse 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 emissions can be maintained with baghouse prior to additional lime and water injection
DSI or carbon injection system	Require minimum flue gas flow prior to sorbent injection. Trona and SBS systems require minimum temperature. Do not inject carbon while firing oil	Require minimum flue gas flow prior to sorbent injection Trona and SBS systems require minimum temperature. Do not inject carbon while firing oil
Baghouse	Pre-coating of bags required prior to startup	Pre-coating of bags required prior to startup
ESP	Energize when flue gas temperature >250°F	Energize when flue gas temperature >250°F

Shutdown Operating Conditions

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 and coal firing is reduced until the unit reaches a point where the auxiliary fuel can be brought in service.

In an emergency shut down or trip different operating conditions apply. For example, in a trip situation ammonia would be shut off immediately to an SCR or SNCR and water or slurry feed discontinued to a spray dryer, CDS or NIDS system. But 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 FRP/plastic components.

As an example, Graph 4 shows temperature profiles for at a reactor for an SCR on a coal fired plant during a normal shut down period. For this plant the SCR is taken out of service 2.5 hours prior to shutdown of the unit. Similar to startup conditions, how long the SCR can remain in service is dependent on system design.



Typical Shutdown Procedures:

APC Equipment	Normal Shutdown	Emergency shutdown
SCR	Discontinue ammonia feed at minimum temperature	Discontinue ammonia feed immediately, emissions no longer controlled
SNCR	Discontinue ammonia feed at minimum temperature	Discontinue ammonia feed immediately, emissions no longer

		controlled
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	System can remain in service, number of recycle pumps in service should be limited to minimize blow back into inlet ductwork at reduced flow. Emergency quench available to cool flue gas in the event of a blackout situation. If emergency quench is required, emissions no longer controlled
Spray dryer/baghouse	Discontinue lime slurry feed at minimum temperature and flue gas flow	Discontinue lime slurry feed immediately, emissions no longer controlled
CDS/baghouse	Discontinue water feed at minimum temperature and discontinue lime feed at minimum flue gas flow	Discontinue water feed immediately followed by lime feed, emissions no longer controlled
DSI or carbon injection system	Discontinue sorbent feed at minimum flue gas flow Discontinue Trona and SBS feed at minimum temperature. Shut down carbon injection when firing oil.	Discontinue sorbent injection immediately, emissions no longer controlled
Baghouse	System can remain in service during shutdown. May have to place compartments out of service based on flow and or temperature dependent manufacturers recommendations	System goes into standby
ESP	System can remain in service during shutdown until flue gas temperature is reduced to 250 °F	System goes into standby

Dependent on the APC equipment installed and permit requirements, each plant requires 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.

The Use of a Default Diluent Gas Cap During Startup and Shutdown

There are several components that make up the calculation for determining unit emissions on an emission rate basis. These include a measurement of the flue gas volume, the pollutant emission and a diluent correction factor. Each of these components has inaccuracies or bias in their individual measurements and they are compounded when multiplied together. EPA, in establishment of emission limits, normally only tests at a full load steady state condition.

During a startup flue gas volume will go from 0% to 100% of the CEMs flow measurement and the normally measured diluent, oxygen will go from 20.9% to 3%.

One concern is the ability of CEMS to accurately measure flow and emissions during startup operations. There is no data comparing measured values to CEMS at low flow (<25% design flow) conditions and to what degree does the error at low flow conditions impact a 30 day average.

RATA testing on CEMS Part 75: Gaseous pollutions are normally certified at three concentrations low, medium and high to give a range of precision. However, regarding flue gas volume, RATA is only certified at full load. There is no data on the accuracy over full range of gas flow from initial startup fuel firing to full load.

If monitoring requirements are to be required during startup and shutdown then it is most likely that the existing CEMS will not be capable of measuring the values. It is well known that the emissions can be outside the operating values during the startup and shutdown and the existing CEMS have been designed and installed based on operating ranges.

The resulted changes that will need to be implemented are providing dual range analyzer systems that would include new analyzers, additional calibration gas and supply systems, and doubling the time/cost for quarterly and year end test audits. In addition, the existing Data Acquisition and Handling System (DAHS) will require updating. The end result will double the operating cost and have an initial cost of 50% or greater of the original system.

By not correcting to a diluent about 10% O_2 during startup and shutdowns can cause many orders of magnitude of bias and error to the emission rate calculations. Graph 4 shows how quickly the diluent correction factor increases beyond 10% O_2, increasing error in measurement by the same factor. We would support the use of a default diluent gas values of 10 percent for oxygen or of the fuel-specific carbon dioxide concentration (obtained from a stoichiometric analysis of fuel combustion), as well as a default nominal electrical production rate of 25 percent of rated capacity to be used when calculating emissions rates during periods of startup and shutdown or until the unit achieves an steady state operating level of 10% O_2 whichever comes first.

Current ECMPS reporting requirements under the NOx Budget and Acid Rain program allow for a diluent cap of 15% O2 or 5% CO2 for calculating NOx rate. The duration of use for this diluents cap is not restricted by the reporting instructions. As long as the CEMS readings are below 5% CO2 or above 15% O2 – The diluent cap value can be used in the calculations of NOx rate. Some states also allow the use of the same diluents cap methodology in reporting NOx and CO rate for reporting compliance to NSPS limits and local permit limits. This diluent cap methodology does not apply to SO2 or Heat Input calculations.

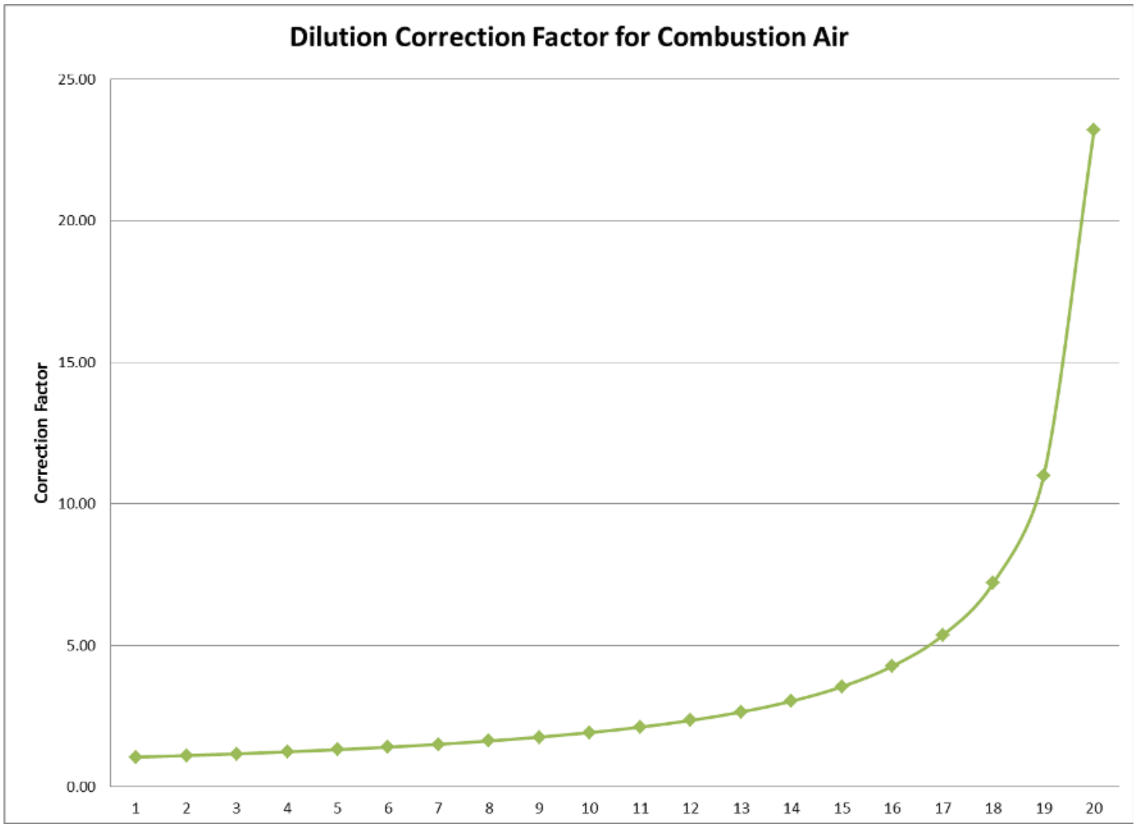
The proposed MATS startup and shutdown exemption language only allows the use of a diluents cap during the startup and shutdown period, which is a very limited time while the boiler is starting up on auxiliary fuel(s). The proposed diluents cap value for MATS is 10% for O2 or the corresponding fuel specific CO2 % (calculated at 9.6% CO2 for non-low ranked coals). This proposal would in essence allow for two different diluents caps, one for NOx rate Acid Rain reporting and another for MATS reporting of SO2, HCl, Hg, and HF. PM is not addressed in the current MATS monitoring plan reporting instructions, but can we assume the diluents cap and electrical production rate cap also applies to PM?

Most state and local air permits for new sources have exemptions for compliance to concentration or rate limits during startup and shutdown periods. This has been the trend for over ten years. These exemptions are typically limited by either a fixed period of time (hours from startup) or when the affected source is able to get their pollution control device in operation and stable, thus allowing for emission limit compliance. Many consent decrees for existing units also include language for startup and shutdown exemptions. The period of time allowed for each startup or shutdown event is typically adjusted depending on the type of startup (cold vs. hot startup of a turbine with an HRSG for example) due to restrictions on the turbine or boiler in the heat ramp and temperature. We urge the EPA to be consistent in their definition of startup and shutdown with the established permit requirements for many sources.

The currently proposed Draft Monitoring Plan Reporting Instructions for MATS (April 2013) proposes a 14.0% O2 diluent cap (19.0% for IGCC), but only for Equations 19-5 and 19-3 (ref. page 73, 77, 79, and 94). We assume the diluents cap method would apply to all formulas and the reporting instructions would be changed to reflect 10.0% O2 or equivalent CO2 % based on equation: $CO2\% = (20.9 – O2\%) / F_o$, where $F_o = 0.209 * (F_d/F_c)$.

For mercury, if an affected unit is using a mercury sorbent trap monitoring system, how do you exclude the mercury collected on the traps for the time during startup from the total mercury captured on the traps? The only way would be to stop pulling samples during the startup or shutdown periods. Elevated mercury levels are quite possible during a cold startup of a boiler and before the scrubber or ACI/DSI systems are in operation. These elevated levels will cause the entire trap collection mass to be higher than normal. The diluent cap or MW load cap will not address this issue.

Graph 5



% O2

Calculating Startup and Shutdown Emission When Multiple Affected EGUs Share a Common Stack

Generally on systems with a common stack, additional instrumentation is included on the outlet of the individual units for monitoring and control. These instruments should be maintained similarly to the CEMs instrumentation in the stack and utilized to confirm individual unit operation during startup and shutdown.

Generally the impact on the common stack emissions is relatively small as the unit that is starting up is at minimal flow conditions when the total emissions is calculated. The only time it is significantly impacted is if relatively high load is required (50% total capacity) prior to starting up APC equipment.

Once startup and shutdown operation has been more clearly defined, the issue for systems with a common stack can be addressed.

Conclusion

ICAC believes that a Work Practice Procedure is the best alternative for establishing startup and shutdown definitions for emission compliance. We would be happy to work with EPA in developing a Work Practice Procedure for the final rule.

ICAC also believes that EPA needs to establish a database of emissions during startup and shutdown conditions to better characterize this issue. The databse should also identify which APC systems are in operation during those periods when they collect the data.

Please feel free to call ICAC at (202) 367-1114 with any questions. As always, we stand ready to work with sources, EPA, and states to achieve feasible, measurable, and practical emission limitations.

Sincerely,

Betsy Natz, Executive Director

Attachment Appendix 1

Appendix 1

Analysis and Comments on EPA's Report "Assessment of startup period at coal-fired electric generating units" dated June 17, 2013

The Institute of Clean Air Companies (ICAC) received a copy of U.S. Environmental Protection Agency's (EPA) report "Assessment of startup period at coal-fired electric generating units" on August 19, 2013. Due to the short time available ICAC has not had an opportunity to analyze this report and to perform a comprehensive review in accordance with our procedures. ICAC would like to request that we be able to respond to this report after the close of the comment period on August 26.

In principal we acknowledge EPA's approach of using statistical operating date to identify the boundaries of startup and shutdown for coal fired electric generating units (EGUs). As we have previously stated, gross generation is not the key to operating air pollution control equipment; however, this report does clarify certain points in the operations of EGUs.

ICAC has made the following observations about this report while we are performing an in-depth review.

- EPA correctly identified the three general classifications of startup used in the power industry.
- However, in the analysis of data presented in figures 9, 10, 12 13, 14, 16, 21, 22 etc., EPA did not appear to analyze the data for each of the three startup conditions. It appears that EPA aggregated the startup data. The significant emissions and time limitations for these startup conditions and should be evaluated separately. EPA did not differentiate startup requirements or timing based on this difference. Instead, their "average" start is skewed heavily by hot restarts.
- EPA used the average or median to develop their conclusions. We believe that this is not the correct approach to setting regulatory limits. EPA should use the upper boundary of the 95% confidence levels to make sure that plants can comply.
- The quartile data range is significant in every chart produced in this report and indicates many EGUs may not be able to comply with the time limits EPA has proposed.
- On several projects EPA has proposed in Consent orders NOx emission in the range of 0.05 to 0.07 lb/MMBtu. However, when you look at figures 13, 14, 21, and 22 SCRs using EPA's data do not reach these levels.
- It is of interest to note that EPA did a startup analysis of SCRs which are not integral to the MATs rule.