



Research article

Dry sorbent injection of trona to control acid gases from a pilot-scale coal-fired combustion facility

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Abstract: Gaseous and particulate emissions from the combustion of coal have been associated with adverse effects on human and environmental health, and have for that reason been subject to regulation by federal and state governments. Recent regulations by the United States Environmental Protection Agency have further restricted the emissions of acid gases from electricity generating facilities and other industrial facilities, and upcoming deadlines are forcing industry to consider both pre- and post-combustion controls to maintain compliance. As a result of these recent regulations, dry sorbent injection of trona to remove acid gas emissions (e.g. HCl, SO₂, and NO_x) from coal combustion, specifically 90% removal of HCl, was the focus of the current investigation. Along with the measurement of HCl, SO₂, and NO_x, measurements of particulate matter (PM), elemental (EC), and organic carbon (OC) were also accomplished on a pilot-scale coal-fired combustion facility.

Gaseous and particulate emissions from a coal-fired combustor burning bituminous coal and using dry sorbent injection were the focus of the current study. From this investigation it was shown that high levels of trona were needed to achieve the goal of 90% HCl removal, but with this increased level of trona injection the ESP and BH were still able to achieve greater than 95% fine PM control. In addition to emissions reported, measurement of acid gases by standard EPA methods were compared to those of an infrared multi-component gas analyzer. This comparison revealed good correlation for emissions of HCl and SO₂, but poor correlation in the measurement of NO_x emissions.

Keywords: coal combustion; acid gases; dry sorbent injection (DSI); trona; MATS; emissions reduction

1. Introduction and Background

For the past several decades in the United States, coal combustion emissions, both particulate and gaseous, have been the focus of regulation by the United States Environmental Protection Agency (US EPA). Progressively more stringent regulations have forced industry to consider both pre- and post-combustion controls to reduce or eliminate many pollutants present in these emissions. For instance, low NO_x burners, lower sulfur and/or chlorine coals, and substituting cleaner burning natural gas have been considered for pre-combustion controls; while selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), flue gas desulfurization (FGD), electrostatic precipitators (ESP), and fabric filters/baghouses (BH) have been considered for post-combustion controls. As limits on emissions from the combustion of fossil-fuels will likely continue to be progressively more stringent, it will be imperative for industries to consider not only new control technologies, but also various combinations of existing control technologies as well as cleaner burning fuels.

Acid gas emissions, e.g. sulfur dioxide (SO₂), sulfur trioxide (SO₃), hydrochloric acid (HCl), hydrofluoric acid (HF), and nitrogen oxides (NO_x), from coal and oil-fired facilities have been subject to many federal and state regulations since the 1990s and even earlier. With the initial implementation of EPA's Clean Air Act Amendments in 1990, many in the industrial sectors were able to meet acid gas regulations by either switching fuels to lower sulfur coal, natural gas, or by purchasing SO₂ emissions credits [1,2].

Emissions from municipal waste facilities, hazardous waste combustors, and steam electric generating units (EGUs) in particular have come under scrutiny as they are associated with high levels of acid gas emissions from the combustion of high-sulfur coals [3]. The US EPA has very recently proposed and promulgated the Mercury and Air Toxics Standard (MATS) rule [4] that, among other things, requires the use of maximum achievable control technologies (MACT) to achieve acid gas emission limits. These emissions regulations were scheduled to take effect in April 2015, but many state environmental regulating/permitting agencies have the option to delay compliance of the more stringent limits for up to one year [5]. Due to these impending lower limits, consideration for retrofitting with additional (potentially costly) control technologies has become a necessary reality for many facilities affected by the MATS rule. The EGU sector is potentially best suited for compliance with the new regulations as nearly 64% of the industry has FGD technologies that already comply [5]. For the remaining ~40% of the utility sector, and many other sectors using oil- and coal-fired combustion, facility retirement or retrofitting with FGD control technologies (either separately or in tandem) is an option for compliance [5].

The three most widely implemented technologies for controlling acid gases from coal combustion facilities are wet, spray-dry, and dry scrubbing; and moving forward these technologies or a combination of technologies could be necessary. Wet-scrubbing, which typically uses an aqueous limestone slurry, can provide better than 95% SO₂ removal and, as of the early-2000s, comprised roughly 85% of the FGD systems deployed in the US [6]. Alternatively, dry-scrubbing, which typically uses a sodium-based dry powder or lime, has been shown to provide less than 80% SO₂ reduction, but as of the early-2000s only comprised roughly 3% of the FGD systems deployed in the US [7].

1.1. Acid gas removal through wet-scrubbing and spray-dry scrubbing

Wet-scrubbing is the most commonly used control technology in the United States for the control of acid gases [7]. Wet-scrubbers are used on a wide size range of coal and oil firing units, ranging from roughly 50 to 15000 MMBtu/hr (5 to 1500 MW_e), but can be costly to construct and operate particularly for retrofitting [7]. This technique for SO₂ control is typically accomplished at relatively low temperatures and with a limestone slurry [2]. Spray-dry scrubbing typically uses a hydrated lime slurry which dries in process. Both wet scrubbing and spray-dry scrubbing create a high gas/water interfacial area facilitating dissolution of acid gases into the liquid. In spray-dry scrubbing, acid gas removal continues after the reagents are surface dry and are dependent on the relative humidity of the gas.

Despite the higher cost associated with using wet-scrubber technology (i.e. high capital investment and costs associated with handling of waste), this technology is popular amongst coal-fired electric utilities because of the low cost of limestone and high SO₂ removal capability [8]. Further, there is a potential for synthetic gypsum to be produced and sold commercially, generating an additional cost offset for the facilities taking advantage of this market [6].

1.2. Acid gas removal through dry sorbent injection

Dry scrubbing using dry sorbent injection (DSI) for removal of acid gases from emissions generated through coal combustion is also a possible cost effective option to meeting and/or exceeding current and upcoming emissions standards imposed by federal and state governments. Typically, DSI in the United States has been limited to smaller combustion units, less than 3000 MMBtu/hr (300 MW_e), but upcoming regulations may increase the use of this technology [7]. This technique has relatively low capital investment and is simple to retrofit, but depending on the level of sulfur that exists in the flue gas, the cost of sorbents can be high and disposal of the waste products can add more operating costs [7]. To accomplish removal of acid gases through DSI, an alkaline solid, is typically injected into the flue gas stream. The injection process parameters include temperature, residence time, and sorbent surface area.

For sodium-based sorbents, a powder such as sodium bicarbonate (NaHCO₃) or sodium sesquicarbonate (trona—Na₂CO₃·NaHCO₃·2H₂O) is injected. The sodium sorbent is calcined, releasing water vapor and CO₂, and the resulting micropores created by this process enhance removal through a combination of increased surface area and solid-gas reactions with the acid gases [9]. Then, the acid gases (now salts) are removed with ash via the PM control device (e.g. ESP or BH). Three suggested injection locations are just downstream of the burner where temperatures range from 1800–2200 °F, just downstream of the superheater where temperatures range from 800–1200 °F, or just downstream of the air preheater where temperatures average roughly 300 °F [10]. The more elevated temperatures (>900 °F), however, may cause damage to the facility and/or degradation of the sorbent and have therefore typically been avoided [11].

Two of the advantages of using trona, as opposed to sodium bicarbonate, are that it can be injected at essentially any location in the flue gas duct as long as the temperature exceeds 275 °F, and that no additional water injection is necessary [12]. A major disadvantage of sodium-based sorbents is that they are water-soluble. Thus, use of these sorbents can cause contamination by leaching into surrounding soil and water. Further, it has been shown that trona used for SO₂ control increased the pH of the waste product (fly ash and trona residuals) resulting in increased leaching of arsenic and

selenium [13]. Trona injection is also known to increase nitrogen dioxide (NO₂) emissions despite NO_x control in conditions typical of coal combustion sources [8]. Another consideration for the use of sodium-based sorbents for acid gas removal is the effect this addition has on particulate emissions. Particulate emissions can be affected by increased loading to the ESP or BH, changes in electrical resistivity of the particulate, changes in particle size distribution, and thus potential changes in the collection efficiency of the PM control device [14].

The current study investigates DSI with trona as a means to reduce acid gases (specifically HCl) by 90% as compared to the baseline of no sorbent injection. Typically trona is injected at high temperatures (+700 °F) to increase reactivity and at a location to increase residence time, maximizing contact with the flue gas pollutants [11]. However, for this investigation trona was injected at approximately 300 °F as high temperature injections are difficult to achieve without major changes to existing plants due to potential damage to downstream PM control technologies such as BH or ESP through the production of sodium bisulfate [15]. Injection at lower temperatures is expected to require greater quantities of sorbent to achieve comparable control [3]. In addition to quantifying the reduction of acid gases with the injection of trona at various normalized stoichiometric ratios (NSR), other gaseous and particulate emissions were measured and reported here.

2. Experimental Approach

The focus of the current investigation was on quantifying the changes in gaseous and particulate emissions that occur from bituminous coal combustion with the dry sorbent injection of sodium sesquicarbonate, or trona. Specifically the reduction of HCl was of interest. Therefore the amount of trona injected was increased until a reduction in HCl of 90% was achieved using either the ESP or the BH.

2.1. Facility

This study was completed using the U.S. EPA's Multi-Pollutant Control Research Facility (MPCRF). This down-fired combustor facility is rated at 4 MMBtu/hr, roughly 1.2 megawatt thermal (MW_t), and is capable of operating on natural gas, distillate fuel oil, as well as a variety of pulverized coals and biomass products. The combustor is refractory-lined and utilizes a low-NO_x burner. Several heat-exchangers are located downstream of the furnace to simulate superheater, economizer and air heater outlet conditions, and to preheat the combustion air (when necessary). This is to closely mimic time-temperature profiles of full-scale electric utilities. After passing through the heat exchangers, the flue gas can be directed in various flow paths toward several options for clean-up of emissions. This facility is equipped with SCR for NO_x control, an ESP and BH (used independently) for PM control, and a lime wet-scrubber for control of SO_x and other acid gases. The MPCRF provides flexibility as it can be configured to incorporate a number of control technologies while excluding control technologies not of immediate interest.

A layout of the facility, as configured for the purposes of this investigation, is shown in Figure 1. With the exception of the first heat exchanger, which is attached directly to the side of the furnace, all downstream connections are made through insulated stainless steel ducts. Numerous ports are provided throughout the facility for temperature measurements, injections, and sampling activities. Fuel and air inputs are precisely measured and controlled to maintain target firing rates and combustion stoichiometric ratios (SRs). All solid fuel for testing is pulverized at a separate on-site facility, and is

fed using a feedback-controlled loss-in-weight screw feeder and conveyed to the burner pneumatically by the primary/conveying air blower (feeding a steady flow of nominally 85 scfm of air, measured by an orifice meter). Secondary air flow is controlled by a variable frequency drive feeding its blower motor, and measured by an orifice meter.

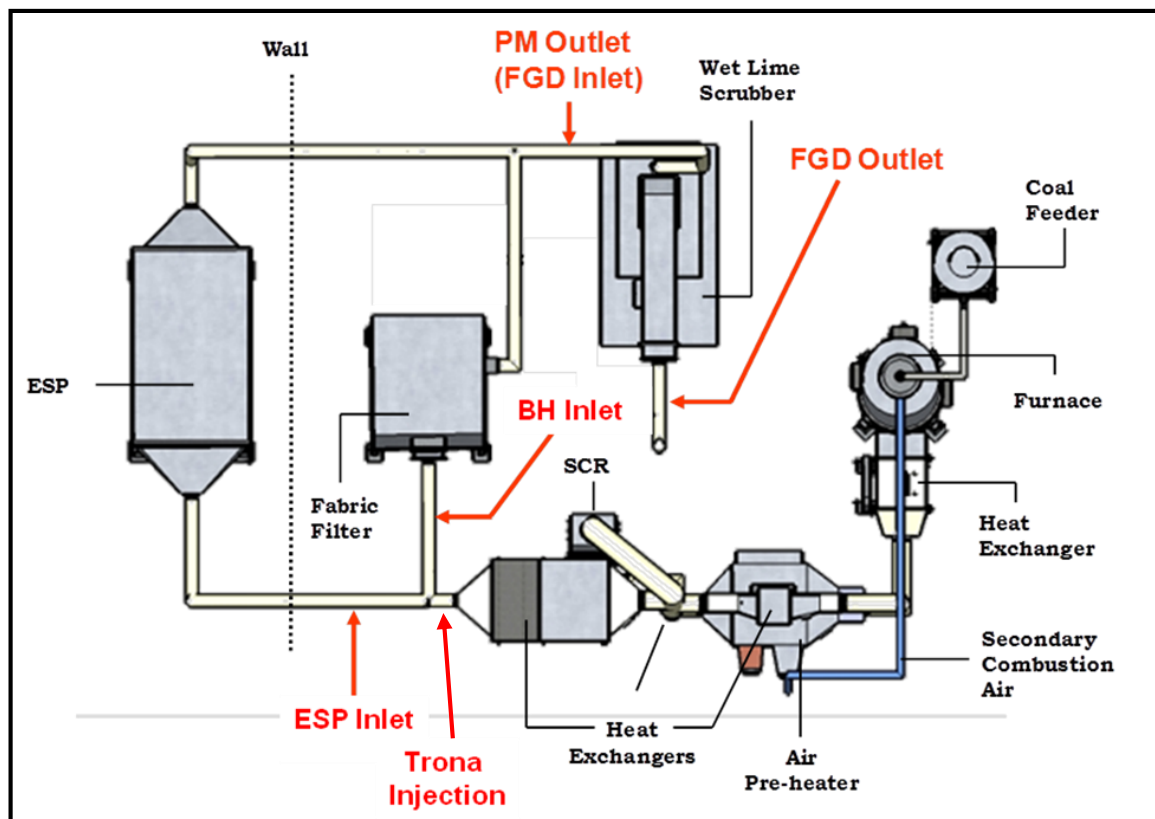


Figure 1. Plan view schematic of the MPCRF with injection port labeled.

2.1.1. Combustor

The MPCRF combustor consists of a refractory-lined combustion chamber with a burner on top, various ports, access doors and temperature probes on the sides, and a side-exit for the combustion gases near the bottom. Internally the vertical cylinder is 42 inches in diameter and 19.5 ft tall; along with refractory-lined flue gas exit passage (leading directly into the first heat exchanger), the combustor has an internal volume of approximately 195 ft³. The internal temperature is not allowed to exceed 2650 °F, so the combustor includes small cooling surfaces (or slag tubes) to help keep that limit from being exceeded while maintaining chosen SR. The multi-fuel burner is based on a design by International Flame Research Foundation with a movable-block swirl adjustment technology. The burner has dedicated injection ports for natural gas, conveying air (or primary air), and secondary combustion air. This allows for individual fuel firing or many combinations of co-firing scenarios. The combustor is typically heated up to temperature on natural gas and then switched over to burn coal, where it is often operated at nominally two thirds maximum firing rate, or 2.5 MMBtu/hr.

2.1.2. Selective catalytic reduction technology

The SCR for this facility consists of three full-length sections of commercial SCR honeycomb catalyst elements in series, each equipped with a soot blower. Anhydrous ammonia is injected into the flue gas immediately upstream of a flow straightener prior to the first element. This SCR can operate in the temperature range of 700 to 740 °F, and has a V₂O₄/WO₃ catalyst manufactured by Cormetech, Inc. However, for the purposes of the current study, the catalysts were removed from the system to simulate bypassing an SCR. The decision to operate without the catalyst in place was made for the current test, but seasonal use of SCR in industry, and the effect of DSI on NO_x emissions could make testing with the SCR in-place of interest for future studies.

2.1.3. Particulate matter control technologies

As previously stated, the MPCRF is designed such that the operator can choose to send the flue gas stream through either the ESP or the BH for control of PM. Both of these units were designed specifically for this pilot-scale facility. The ESP is a BETH model KEF 4 standard “dry” ESP and was designed to capture fly ash from the variety of coals combusted in the facility. This ESP has mechanical rappers to remove the caked fly ash from the collection plates and is approximately 14.8 ft (L) × 6.2 ft (W) × 21.7 ft (H). The electrode collection plate surface has a total area of 775 ft² in a single field. The collected solids are discharged through a rotary valve mounted on the base of the unit. The ESP has a specific collection area of approximately 650 ft²/1000 acfm.

The BH is nearly 32 ft tall and has a footprint of 6 ft x 6 ft. Within the housing there are 24 Ryton bags, 8 ft long with a 6 in diameter providing an air-to-cloth ratio of approximately 3.9 ft/min. Flue gas enters through a sidewall under the bags and then flows upward through the bags to collect the particulate matter. Once the flue gas exits the bags and outlet plenum, the flow is directed to the scrubber. Each row of six bags is pulsed sequentially to clean filter cake from the bags, and the solids are discharged through a rotary valve on the BH hopper.

2.1.4. Sulfur dioxide control

The MPCRF, much like full-scale coal-fired power plants, incorporates a lime-based slurry flue gas desulfurization (FGD) wet scrubber to control sulfur dioxide emissions. The wet scrubber is a natural oxidation multi-rod deck scrubber manufactured by Croll-Reynolds. It is designed with a counter-current vertical column with multiple sections of parallel rods in series for enhanced gas/liquid contact. The scrubber lime-based slurry is sprayed uniformly over the cross section of the rod deck in order to remove the SO₂ and other pollutants. The scrubber slurry then passes into the holding tank at the base of the scrubber where a concentrated hydrated lime slurry is added to maintain the desired slurry pH, which for this facility is near neutral. The scrubber slurry is then recirculated from the holding tank to the spray header above the rod deck, and the excess solids are removed in canister filters. This particular scrubber is designed specifically for the MPCRF to remove greater than 95% SO₂ at 1200 scfm.

2.2. Dry sorbent injection and sorbent characteristics

For the entirety of these tests, trona was injected into the flue gas after the final heat exchanger (Figure 1) but prior to any PM control—ESP or BH. This location was chosen based on the injection

temperature (ranging from roughly 272–301 °F) and the need to maximize residence time for the trona to mix and react with the flue gas. Subsequently, the residence time upstream of the PM control was calculated to be roughly 0.5 seconds. The feed system, including the hopper holding the trona, was on a scale and the injection rate was measured by loss in weight. The trona was fed into the flue gas through a pneumatic eductor, either a Penberthy GH ½” or a GH ¾” depending on the needed feed rate for a given condition. During testing with both the ESP and the BH, conditions which required feed rates of sorbent up to 29 lb/hr used the ½” eductor, but once 30 lbs/hr was required (to achieve 90% control of the HCl) the ¾” eductor was used.

The trona used for the current investigation was provided by Solvay Chemicals, Inc and was the SolvAir 200 product. This sorbent, prior to delivery and testing in our facility was milled to have a particle diameter at or below 200 µm. No further milling of the trona was completed prior to the testing, but the trona was independently analyzed for size to find a median particle size of approximately 31 µm.

Normalized stoichiometric ratio (NSR) was calculated to represent the level of trona injection. For the current investigation, the NSR is defined as the molar ratio of the equivalents of alkali injected as trona to the equivalents of SO₂ and HCl emissions upstream of trona injection. The trona alkalinity was analyzed and found to be approximately 98% as sodium sesquicarbonate, and thus an alkalinity of three equivalents per mole.

2.3. Gaseous and particulate measurements

For this study, a suite of instruments was used to measure gas and particle phase emissions from the flue gas in multiple locations of the ductwork. Samples for emissions reported here were almost always collected and/or measured upstream of sorbent injection and downstream of the PM control device (either ESP or BH), which for the purposes of this study will be referred to as inlet and outlet, respectively. Continuous emissions monitors (CEMs) were used to measure many compounds including (but not necessarily limited to): CO, CO₂, O₂, NO_x, SO₂, and HCl. In many cases an additional method or technique was used to measure these compounds as well, and are reported and discussed in detail in subsequent sections. Particulate matter measurements for this study included fine PM mass, fine PM particle size distribution (PSD), elemental carbon (EC), and organic carbon (OC). All PM samples were collected through an eductor-based system with a 2.5 µm cyclone to remove char, large fly ash particles, and sorbent. Inlet PM samples were collected downstream of sorbent injection but upstream of the PM control device. Outlet PM samples were collected downstream of the PM control device but upstream of the wet scrubber. The manufacturer, model, and associated EPA method of each of these instruments is available in the Supplemental Material (Table S1).

3. Results and Discussion

A pilot-scale coal-fired combustor was used to investigate the potential for control of acid gases from the combustion of bituminous coal using DSI of the sodium-based sorbent trona. Both particulate and gaseous measurements were made from the flue gas emissions with the ultimate goal of determining the NSR of injected trona required for 90% removal of HCl. As a results of this investigation, reductions in emissions, comparison of several measurement methodologies, and fine PM emission factors were possible and are discussed in detail within.

A test matrix was completed in which measurements were made at the inlet and outlet of the PM

control devices to determine the removal efficiencies utilizing the ESP and the BH individually. The NSRs tested for the ESP and the BH were 0.59 to 2.40 and 1.13 to 2.20, respectively. Trona was injected at a constant rate upstream of the PM control at a nominal temperature of 290 °F. Each test is comprised of multiple runs aligned with the various integrated sampling techniques. Figure 2 shows the percent reduction of HCl, SO₂, NO_x, PM, EC, and OC for each NSR (test) for measurements taken with the ESP (Figure 2a) and the BH (Figure 2b). The reductions represented in this figure for HCl, SO₂, and NO_x are calculated using data from the instruments that use standard EPA reference test methods (see Table S1). The emissions average and standard deviation across runs for each condition tested, as well as the average trona injection temperature and rate, is available in the Supplemental Material (Table S2). HCl emissions reduction of at least 90% occurred at a NSR = 2.4 (33.2 lbs/hr trona injection rate) while using the ESP, but at a much lower NSR = 1.57 (24.2 lbs/hr trona injection rate) while using the BH. Overall, the SO₂ and NO_x emissions were reduced with increased NSR as well. With both the ESP and the BH, the highest SO₂ removal corresponded to the highest trona injection rate that was tested. Nearly 60% of the SO₂ emissions were removed using the ESP at a NSR = 2.4 and greater than 80% removal with the BH at a NSR = 2.2. This is to be expected as DSI has been shown to be more effective at removing acid gases when using a BH for PM control [12]. Further, Kong and Wood [12] showed data curves for SO₂ removal that considered emissions from “numerous systems over the last 20 years” while using trona for acid gas control; their findings illustrated maximum SO₂ emission reductions of greater than 85%, at a corresponding NSR = 1.5 using a baghouse while the ESP achieved roughly 80% SO₂ reduction at an NSR = 3.5 [12].

Uncontrolled fine PM emissions were significantly lower than projected, 0.29 lb/MMBtu, using AP-42 emission factor for PM_{2.5}; this is likely due to the specific fuel processing and combustion characteristics of the MPCRF. The proximate/ultimate analyses for the bituminous coal used each test day is available in the Supplemental Material (Table S3). Fine PM emissions at the inlet location were not strongly dependent on trona injection rate, suggesting the relatively large trona particles were effectively removed from the sample in the cyclone. Fine PM emissions removal was nearly constant for both the ESP and the BH regardless of the trona injection rate, with an overall reduction average of 97% and 99%, respectively. The ESP provided slightly better EC removal than the BH while providing slightly less fine PM removal. With only a small number of filters collected ($n = 3-5$) at each location for every NSR tested, it is difficult to determine if these trends of EC and fine PM removal are statistically significant. However, this observation could be expanded by future testing on the MPCRF. This could be accomplished by more sampling with not only time-integrated filter samples for EC and a scanning mobility particle sizer (SMPS) for particle size distribution, but potentially by using a nano-MOUDI for filter collection and analyzing each stage.

For several of the measurements made during this investigation, more than one instrument was used simultaneously for comparison. The primary purpose of the duplicate measurements was to provide a continuous indication of HCl during testing. These measurements used a single multi-component infrared gas analyzer (MC3) connected to a time-sharing sampling system to measure both inlet and outlet concentrations. This system did not undergo all of the rigorous performance checks of the EPA instrumental reference methods (e.g. 6C for SO₂ and 7E for NO_x), but were checked for linearity and drift using calibration gas injections at the probe before and after each days' testing. The average emission factors for HCl, SO₂, and NO_x collected from all test conditions (both ESP and BH at varying NSR) with each method are shown in the Supplemental Material (Table S2), and plotted in Figure 3 for both the inlet and outlet sampling locations.

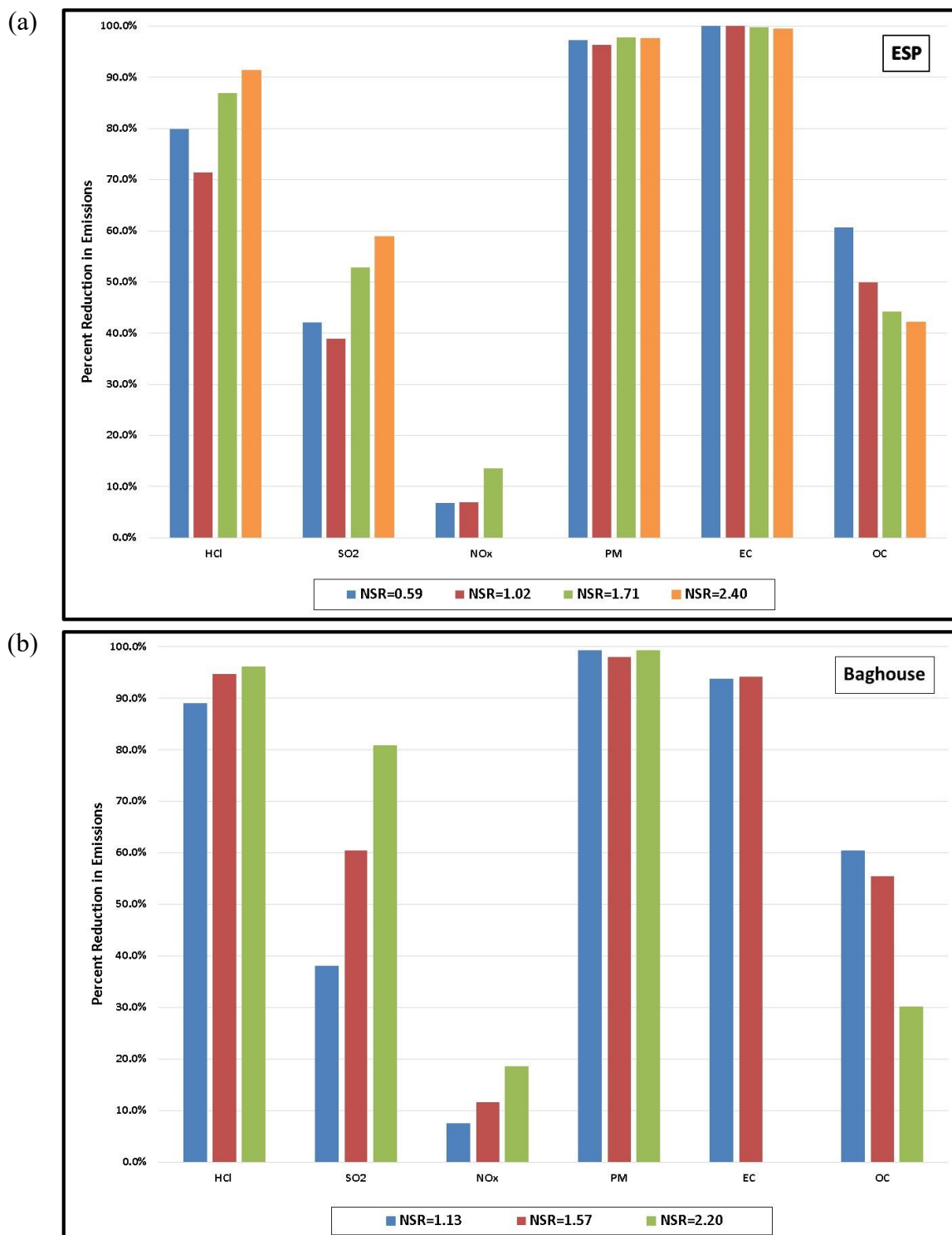


Figure 2. Emissions reduction as a function of NSR for two PM controls—(a) ESP and (b) baghouse. (Note: NO_x data for NSR = 2.4 and ESP is missing due to CEM instrument failure during the test day. EC data for NSR = 2.2 and BH is missing due to a filter collection error at the inlet for that test day.)

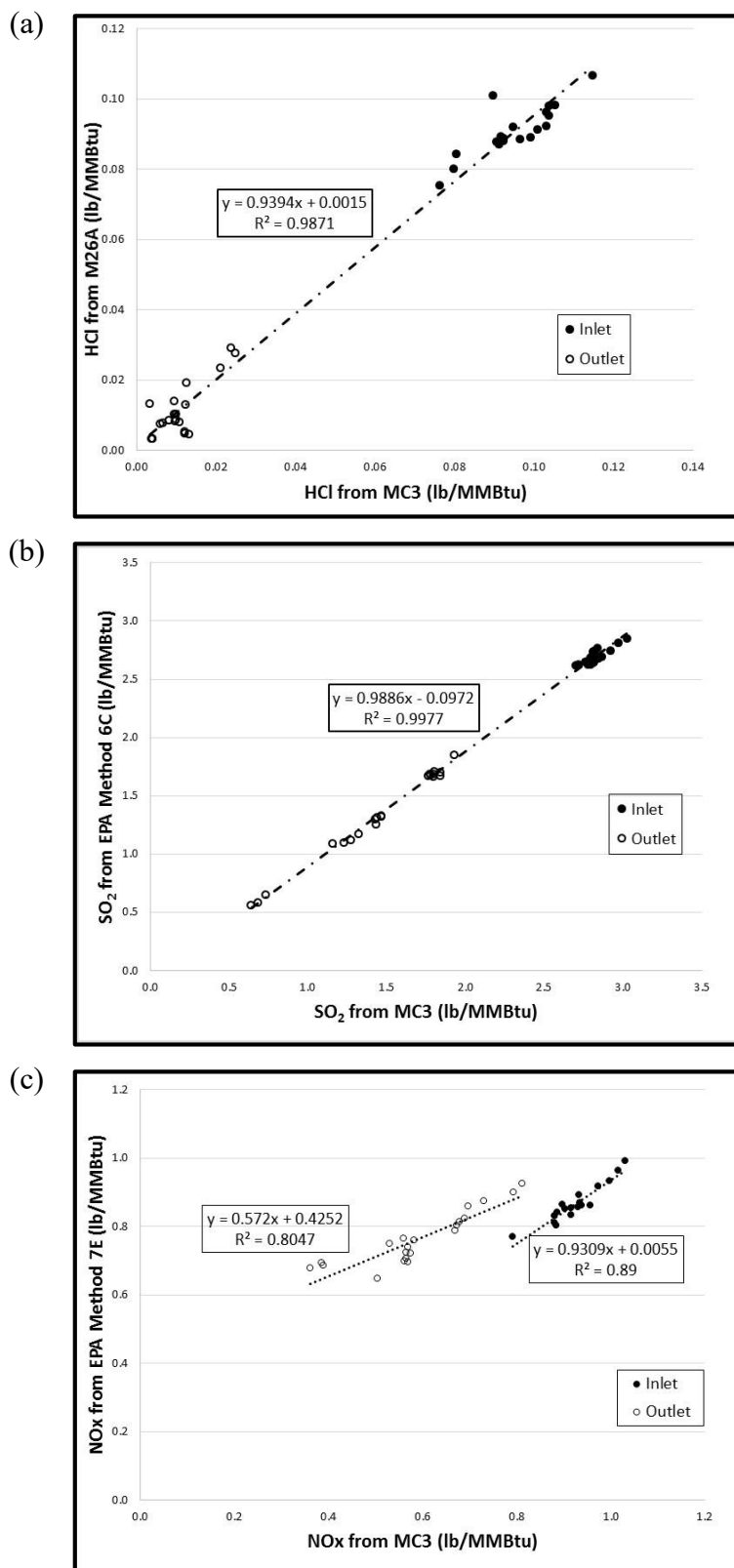


Figure 3. Measurement comparison at both inlet and outlet locations for (a) SO_2 , (b) HCl, and (c) NO_x .

Figure 3a displays the comparison of HCl emissions for two measurement techniques - the time-integrated sample collected via EPA Method 26A (impinger method) and the semi-continuous

measurement averages from the MC3. Overall, there is good correspondence between the two procedures for HCl over a broad range. Both utilize a heated filter which may introduce a bias for either method in the presence of residual trona. Further, while the correlation is strong, there is scatter, which is not unusual when comparing a time-integrated sample, such as Method 26A, to a more continuous measurement.

When comparing two continuous measurements, like the SO₂ emissions measured via EPA Method 6C and the MC3, the correlation is much stronger and has less scatter (see Figure 3b). Figure 3c, however, shows what can happen when data reported are not representative of “apples to apples” comparison. EPA Method 7E uses a NO₂ to NO converter and chemiluminescent analysis to measure NO_x, where the MC3 only measures NO. There remains reasonably good correlation of NO_x to MC3 measured NO at each sample location but the overall correlation is poor. While NO₂ was not separately measured during this study, a possible cause of the two distinct relationships shown in Figure 3c is oxidation of NO to NO₂ across the PM control device. Other interferences could come from water vapor or SO₂ in the flue gas.

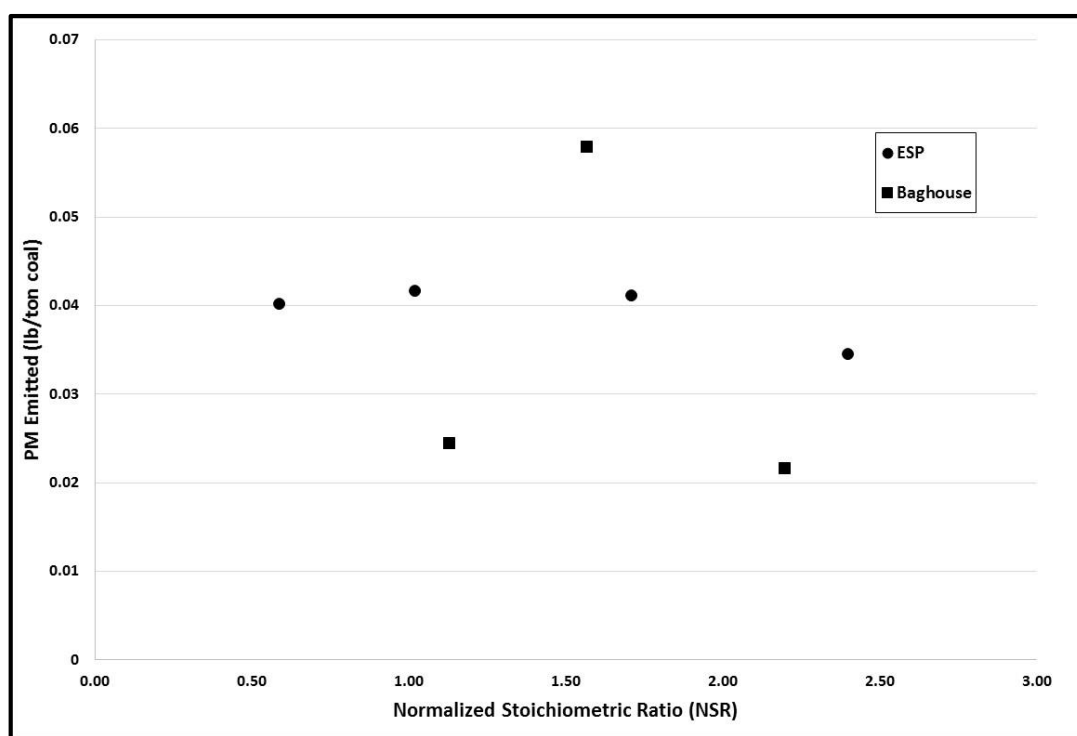


Figure 4. Particulate emissions utilizing an ESP or baghouse as a function of NSR.

Figure 4 represents fine PM emission averages, post-ESP or post-BH, at increasing NSR. There is no clear trend in fine PM emissions exiting either the ESP or the BH despite the marked increase in trona injection rate. This is consistent with the observations at the PM inlet location that trona was largely excluded from the fine PM sample. Multiple data points (minimum of three at each inlet and outlet location) were collected from the system while operating at steady-state to determine these averages, but are not enough to adequately determine a trend or its statistical significance for either control device. It is observed from this investigation that the fine PM is being heavily mitigated, but still begs the question as to how much of the ultrafine PM ($d_{\text{PARTICLE}} \leq 1$ micron) might be escaping, particularly as their effects on human and environmental health have been a topic of much debate for

many years [16-18]. Therefore, additional testing would be beneficial in determining the effects of trona injection on fine (and ultrafine) PM emissions from either the ESP or BH as a function of NSR.

4. Conclusion

The results presented here describe the gaseous and particulate emissions of a pilot-scale coal-fired combustor burning bituminous coal and using sodium-based dry sorbent injection of trona to reduce acid gas emissions. The coal-fired combustion facility used for this investigation also incorporated a low-NO_x burner and PM control via ESP or BH. The trona was injected at various rates, represented by increases in normalized stoichiometric ratio, and was incrementally increased each test day until the investigation goal of 90% HCl emissions removal was achieved using each of the PM control devices individually.

From this investigation it is shown that dry sorbent injection of trona is a viable control technology for removal of HCl and SO₂ from the emissions of coal combustion. Specifically, by increasing the injection rate (or NSR) of trona it is possible to achieve 90% HCl removal with either an ESP or BH with short flue gas residence times (i.e. 0.5 s), but more sorbent is required to achieve this reduction with an ESP than a BH. However, even at these high rates of trona injection, the ESP and BH were able to achieve substantial fine PM removal, greater than 95%. Further, it was shown that while the ESP and the BH achieved high levels of PM removal, there is still quite a bit of fine (likely predominantly ultrafine) PM escaping the controls. Future testing is needed and will likely be completed to further investigate these observations.

Simultaneous sampling with standard EPA reference test methods and a MC3 showed good correlation between measurements for both HCl and SO₂. MC3 measurement of NO_x measurements were limited to NO due to the detector suite of the instrument used. There was very poor correlation of NO_x to MC3 measured NO across sample locations, which may be caused by NO₂ production and by interference with other emissions.

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Conflict of Interest

All authors declare no conflicts of interest in this paper.

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