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DIVISION OF AIR
RESOURCE MANAGEMENT

Jeffery F. Koerner, Program Administrator
Office of Permitting and Compliance
Division of Air Resource Management
Florida Department of Environmental Protection
Bob Martinez Center
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: Draft Air Construction Permit No. 0050014-023-AC for Lansing Smith Units 1 and 2

Dear Mr. Koerner:

Thank you for accepting these comments on behalf of the Sierra Club, Earthjustice, and their hundreds of members in Florida who will be substantially affected by this draft permit for construction and a test burn program at Gulf Power's Lansing Smith power plant. The air construction permit does not assure compliance with state law, and should not be issued in its current form.

Unfortunately, the Lansing Smith Test Burn of Emissions Control Sorbent Additives permit cannot assure compliance with Florida's Prevention of Significant Deterioration (PSD) program, pursuant to Rule 62-212.400, F.A.C., or the general preconstruction review permitting requirements of Rule 62-212.300, F.A.C. This permit, therefore, may not properly issue. The Florida Department of Environmental Protection (hereinafter "the Department" or "DEP"), may issue a permit only after it receives reasonable assurance that the installation will not cause pollution in violation of any of the provisions of Chapter 403, F.S., or the rules promulgated thereunder. F.A.C. 62-4.030; *see also* 62-4.070(1) (same); 62-212.300(3)(a)(2) (requiring applicant to demonstrate that they will comply with all relevant law). This permit violates this requirement. For the reasons explained in the attached analysis, the permit does not reasonably assure compliance with the general preconstruction review permitting requirements of Rule 62-212.300, F.A.C., or Florida's PSD program under Rule 62-212.400, F.A.C.

I. Preconstruction Requirements

This is an air construction permit. *See* Draft Air Permit No. 0050014-023-AC at 1. As such, the General Preconstruction Review Requirements of Rule 62-212.300, F.A.C. are applicable ("This rule shall apply to the proposed . . . modification of all emissions units and facilities for which an air construction permit is required."). As specified in the rule,

> Each applicant for an air construction permit for an emissions unit subject to this rule shall provide . . .

1. The nature and amounts of emissions from the emissions unit, including baseline actual emissions and projected actual emissions . . . .
2. The location, design, construction, and operation of the emissions unit to the extent necessary to allow the Department to determine whether construction or modification of the emissions unit would result in violations of any applicable provisions . . . or Department air pollution rules, or whether the construction or modification would interfere with the attainment and maintenance of any state or national ambient air quality standard.

62-212.300(3)(a), F.A.C.

For any air construction permit, the "Department shall determine whether a major modification will occur for each PSD pollutant." 62-212.400(2)(a), F.A.C. For modifications at existing emissions units, the Department shall apply the "Baseline Actual-to-Projected Actual Applicability Test." 62-212.400(2)(a)1., F.A.C. To determine if the PSD program applies, the Department must determine whether there will be a "significant emissions increase of a PSD pollutant," which occurs if the difference "between the projected actual emissions and the baseline actual emissions equals or exceeds the significant emissions rate for that pollutant." 62-212.400(2)(a)1., F.A.C.

II. Gulf Power and the Department Failed to Comply with the Applicable Preconstruction Requirements

As stated in the document entitled "Smith Sorbent Injection Test Burn Project Description," attached to Gulf Power's Electronic Permit Submittal and Processing System (EPSAP) application 3549-1, particulate matter (PM) emissions are expected to increase during the testing of the sorbents as proposed under this air construction permit. Smith Sorbent Injection Test Burn Project Description, attached to EPSAP application 3549-1 (hereinafter "Project Description").

The significance threshold at which the PSD requirements will become applicable is 25 tons per year for PM overall. 62-210.200(282)(a)1.d., F.A.C. However, the PSD significance thresholds for PM measuring 10 microns or less (PM_{10}) and PM measuring 2.5 microns or less ($PM_{2.5}$) are lower than the overall PM threshold, at 15 tons per year and 10 tons per year, respectively. 62-210.200(282)(a)1., F.A.C.

Instead of providing reasonable assurances regarding the validity of the projected actual emissions, as is clearly required by rule 62-212.300(3)(a), F.A.C., Gulf Power states that since 300 tons of sorbent material is to be utilized in the study, and the existing hot and cold side electrostatic precipitators (ESPs) have a removal efficiency of 98%, the maximum emissions increase will be 6 tons of PM, likely to be offset by some possible use of lower-ash coal. Project Description. The Department simply adopts this analysis, stating that "According to the applicant, the project is expected to increase PM emissions . . . by less than 6 tons/year." Technical Evaluation & Preliminary Determination, Project No. 0050014-023-AC at 7 (hereinafter "TEPD"). Therefore, "the project does not result in a significant increase in emissions." TEPD at 8.

Florida rules require more of an analysis than accepting a statement from an applicant that has no documentation or analysis to support it. In fact, the emission calculation for PM contained in EPSAP application 3549-1 is the exact same as in previous EPSAP applications for other projects at Lansing Smith. *Compare* EPSAP application 3549-1 *with* EPSAP application 3340-1. Far from doing the required Baseline Actual-to-Projected Actual Applicability test to determine if there was going to be a significant increase in PM emissions, Gulf Power and the Department do no analysis at all of potential emissions, other than to say that since only 300 tons of PM are being added, only 6 additional tons of PM could come out. This reasoning is flawed for several reasons, discussed below, and does not meet the requirements of 62-212.300 or 62-212.400, F.A.C. To comply with the rules, Gulf Power *must* provide reasonable assurances of the validity of its projected actual emissions from the Lansing Smith tests. Gulf Power and the Department are not permitted under the rules to do a back of the envelope calculation to guess at what increase in emissions a certain modification will have.

Gulf Power's copy-and-paste analysis fails to resolve whether the PM emissions from the 300 tons of sorbents used in its proposed testing program will qualify as PM_{10} or $PM_{2.5}$, or whether the addition of those sorbents or different kind of coal will lead to an increase in PM_{10} or $PM_{2.5}$ emissions, or to provide any compelling analysis as to PM emissions overall. It is clear from Gulf Power's application that PM emissions have the potential to exceed relevant PSD thresholds for PM, meaning that the Department cannot assure compliance with its regulations or the Clean Air Act without a more complete application from Gulf Power. Under Florida law, Lansing Smith must provide a thorough analysis of its potential emissions, sufficient to provide the Department and the public reasonable assurance that PSD significance thresholds will not be violated.

As Gulf Power's application explains, the electrostatic precipitator (ESP) efficiency at Lansing Smith when combining the hot and cold ESPs is 95.0-99.9%. EPSAP application 3549-1 (under "Emissions Unit Control Equipment"). This range in potential efficiency belies Gulf Power's claim, in calculating its potential PM emissions, that 98% removal is "a conservative PM removal efficiency." Project Description. If, for example, the 95.0% efficiency were to apply during the tests the increase in PM emissions from 300 tons of sorbent would then be 15 tons. If this increase was predominantly comprised of $PM_{2.5}$ or PM_{10}, than the significance threshold for PSD applicability will be exceeded. Gulf has not demonstrated that its emissions will not trigger the $PM_{2.5}$ or PM_{10} PSD thresholds; indeed, it has not even attempted to separately calculate the relative fractions of these PM components in its emissions. Because the $PM_{2.5}$ or PM_{10} PSD thresholds could be exceeded at the control efficiency of the Lansing Smith ESP, Gulf has not provided reasonable assurances that it will comply with applicable law.

Further, as we discuss below, the sorbent changes which Gulf Power proposes to test are known to decrease ESP efficiency. These technologies therefore increase the risk that the ESP will operate below the 98% efficiency which Gulf Power uses as the sole basis for its PSD applicability discussion. They thus increase the risk that the $PM_{2.5}$ or PM_{10} PSD thresholds will be breached. In fact, if ESP efficiency drops sufficiently, even the generic PM PSD threshold of 25 tons per year may be breached.

Gulf Power provides no direct assurances – much less substantial evidence – to the contrary. Instead, it assures the Department that whatever PM emissions increase there will be will at least be partially offset by the use of Colombian coal, but there is no analysis anywhere in the EPSAP application or project description to substantiate this claim, and no analysis as to the particle size of the PM that the Colombian coal will generate as a substitute for the coal Gulf Power currently burns at Lansing Smith. Florida Rules 62-212.300 and 62-212.400, F.A.C., require more, both from Gulf Power and from the Department. This analysis assumes, of course, that the ESP can even maintain its current efficiency, which, as pointed out below, is far from guaranteed, and for which, of course, Gulf Power has provided absolutely no analysis.

Moreover, Gulf has provided no analysis as to whether the ESP will be able to achieve 95% efficiency with the new processes being proposed in the test burn, which include the potential addition of ClearChem, Hydrated Lime, Trona, powder activated carbon, as well the use of Colombian coal. Each of these sorbents can reduce ESP efficiency.

Powder activated carbon has the potential to have an "impact on the bulk properties of the ash collected on the [ESP] plates. A change in the overall resistivity of the material could result in a significant degradation of the performance of the ESP." Michael Durha, et. al., Full Scale Evaluation of Mercury Control by Injecting Activated Carbon Upstream of ESPs, at 10 (attached as Attachment A). Another concern with powder activated carbon is "whether the easily reentrainable carbon can be effectively captured in the ESP." *Id.*

ClearChem seems to be relatively new, and the effects of it have not been studied. Gulf Power provides no analysis as to what the effect of adding ClearChem at Lansing Smith will be on the ESP. Even in the corporate presentation on ClearChem, which the Department apparently relies in part upon as the basis for its decision, *see* TEPD at 5, they admit that there will be some "tube deposits and impact on ESP." *See* Attachment B at 4. This corporate presentation seems to be the *only* source of knowledge the Department has about ClearChem. *See* TEPD at 5. The entirety of the Department's analysis of the effect of ClearChem seems to be a summary of a web presentation available via a Google search. Far from providing reasonable assurances that the addition of this unknown chemical combination will not result in the significant increase of a PSD pollutant as required under the rules, this sales-pitch presentation provides no real analysis regarding how ClearChem will affect emissions at Lansing Smith. Despite the conclusion of the maker of ClearChem that ClearChem will have some impact on the efficiency of ESPs, *see* Attachment B at 4, there is no analysis anywhere, by either Gulf Power or the Department, as to what that impact will be and whether that will result in a significant increase in emissions for a PSD pollutant.

Adding Hydrated Lime can also significantly decrease the efficiency of ESPs by effecting fly ash resistivity. Robert Mastropiertro, Impacts of Hydrated Lime Injection on Electrostatic Precipitator Performance, ASTM Symposium on Lime Utilization, June 28, 2012 (attached as Attachment C). The sulfur content of the coal, injection rate, temperature, and flue gas moisture content all impact ESP efficiency when using Hydrated Lime. *Id.* at 9.

Again, there was absolutely no analysis by the Department or Gulf Power as to whether ESP efficiency will be impacted by the addition of these sorbents. The rules specifically require that projected actual emissions be calculated, but neither Gulf Power nor the Department have provided well-substantiated calculations of projected actual calculations under testing conditions. Without that analysis, there is no way of knowing if there will be a significant increase in a PSD pollutant, which in this case, would most likely be PM. It would only take a lowering of ESP efficiency from 95.0% to 91.67% for the addition of the 300 tons of sorbent alone to result in an emissions increase of 25 tons of PM, which is the significance threshold. 62-210.200(282)(a)1.d., F.A.C. More limited efficiency losses could cause Lansing Smith to cross the significance thresholds for PM_{10} and $PM_{2.5}$, or for PM overall when accounting for how the decreased ESP efficiency could mean increased PM emissions from the burning of coal. There has been no analysis as to whether this is expected to occur, and insufficient information is provided to make such an independent analysis, as we do not know how or in what combinations Gulf Power plans to use the sorbents allowed in the proposed air construction permit, and under what conditions Gulf Power plans to use the sorbents.

Far from providing the reasonable assurances as required under the law, Gulf Power has provided no assurances at all that the proposed air construction permit will not cause pollution in violation of any of the provisions of Chapter 403, F.S., or the rules promulgated thereunder. Until Gulf Power provides those reasonable assurances, the proposed air construction permit cannot issue under Florida law.

III. Lansing Smith Should Be Retired

Gulf Power's Lansing Smith plant is an aging facility lacking major pollution controls. This proposed test burn program is merely an attempt to prevent either the inevitable retirement of the plant or the installation of real and effective pollution controls. In addition to posing a serious threat to public health, it is not economic to operate. As explained in Attachment D, Lansing Smith is either going to have to install a scrubber, or retire. The Department should focus on these approaches, to protect the health of Floridians and Florida's environment. The proposed air construction permit does not make sufficient progress in protecting Florida's environment.

IV. Conclusion

In sum, Gulf Power has not provided reasonable assurances that the proposed air construction permit will meet the applicable requirements of the Department's rules, and has not provided reasonable assurances that the proposed air construction complies with the law. Gulf Power has provided no analysis showing that the five separate proposed modifications, either in combination or separately, will not result in a significant increase in a PSD pollutant. Gulf Power has not even provided a statement that the proposed sorbents will not decrease ESP efficiency (and thus significantly increase PM emissions), let alone the analysis that is required under Florida law. No well-supported baseline or projected actual emissions have been provided, as required under Florida law. Until Lansing Smith and the Department undertake the required analyses, the proposed air construction permit cannot issue. The required analyses could find that PSD is triggered, and that the applicable rules and provisions would then need to be followed for Lansing Smith.

In short, because the Department lacks any reasonable assurance that this permit will assure compliance with DEP rules, it must revise or at a minimum not finalize the permit. We would be happy to discuss this matter further with you and your staff, and look forward to the Department's efforts to ensure that the proposed permit complies with DEP's rules and regulations.

Sincerely,

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FULL-SCALE EVALUATION OF MERCURY CONTROL BY INJECTING ACTIVATED CARBON UPSTREAM OF ESPS

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ABSTRACT

Under a cooperative agreement with the Department of Energy National Technology Laboratory (NETL), ADA-ES has conducted a series of tests evaluating the performance of activated carbon injected upstream of electrostatic precipitators (ESPs) for mercury control and the effect of changing operating conditions such as temperature and LOI on natural mercury control. Host site configurations included units burning both Powder River Basin and low sulfur bituminous coals and sites that had high and low natural mercury removal. Results from this test program have shown the viability and limitations of using activated carbon for mercury control with ESPs. This paper includes results from Wisconsin Electric Pleasant Prairie, PG&E NEG Brayton Point, and the recently completed results from PG&E National Energy Groups Salem Harbor Station. This site provided key information on the importance of temperature and LOI in mercury removal with and without activated carbon injection.

INTRODUCTION

The power industry in the US is faced with meeting new regulations to reduce the emissions of mercury compounds from coal-fired plants. These regulations are directed at the existing fleet of nearly 1100 existing boilers. These plants are relatively old with an average age of over 40 years. Although most of these units are capable of operating for many additional years, there is a desire to minimize large capital expenditures because of the reduced (and unknown) remaining life of the plant to amortize the project.

In addition, utilities are being faced with operating in an unregulated competitive environment in which they must strive to be the low cost provider. Since the cost of fuel represents approximately 70% of the incremental cost of generating electricity, it is critical that the plant be able to purchase the cheapest fuels available. It is also critical that these plants are operating reliably, especially during peak demand periods.

Therefore, the industry needs environmental control technologies that will have the following fundamental characteristics:

- Will take advantage as much as possible of existing equipment and minimize the need for installing new major capital equipment;
- Can effectively meet regulations on a wide variety of coal characteristics;
- Will not require additional manpower or specialized technical expertise; and
- Can be installed and operated without jeopardizing the reliability of the generating facility.

This paper provides a summary of the latest information on sorbent-based mercury control technology on coal-fired boilers. New operating and performance data from full-scale installations have proven the effectiveness of sorbent injection for reducing mercury emissions. The paper describes how different coal characteristic, operating conditions, and equipment configurations impact mercury removal.

PROGRAM DESCRIPTION

Injecting a sorbent such as powdered activated carbon (PAC) into the flue gas represents one of the simplest and most mature approaches to controlling mercury emissions from coal-fired boilers. The gas phase mercury in the flue gas contacts the sorbent and attaches to its surface. The sorbent with the mercury attached is then collected by the existing particle control device, either an electrostatic precipitator (ESP) or fabric filter. This combined material consisting of about 99% fly ash and 1% sorbent is then either disposed of or beneficially used.

Under a cooperative agreement from the Department of Energy National Energy Technology Laboratory (DOE/NETL), ADA-ES is working in partnership with PG&E National Energy Group (NEG), Wisconsin Energy Corp., Alabama Power Company, Ontario Power, TVA, First Energy, Hamon Research-Cottrell, Arch Coal, Kennecott Energy and EPRI on a field test program of sorbent injection technology for mercury control. The test program, which took place at four different sites during 2001 and 2002, is described in detail elsewhere (Durham et al., 2001).

Four full-scale demonstrations were conducted during 2001 and one in 2002 with additional tests proposed for 2003. The first program was completed in the spring of 2001 at the Alabama Power E.C. Gaston Station (Bustard et al. 2002). This unit burns a low-sulfur bituminous coal and uses a hot-side ESP followed by a COHPAC^{TM} fabric filter as secondary collector for remaining fly ash and injected carbon. The second program was conducted during the fall of 2001 at the We Energies Pleasant Prairie Power Plant (Starns et al., 2002). This unit burns a subbituminous Powder River Basin (PRB) coal and uses an ESP to collect the carbon and fly ash. The third program was completed in the summer of 2002 at PG&E National Energy Group's Brayton Point Station (Durham et al., 2002). This unit burns low-sulfur bituminous coals and use ESP for particulate control. The fourth program was completed in the fall of 2002 at PG&E National Energy Group's Salem Harbor Station. Salem Harbor fires bituminous coals with an ESP for particulate control and a SNCR system for NO_x control.

ESP TEST SITE DESCRIPTION

We Energies Pleasant Prairie Power Plant

Pleasant Prairie Power Plant is located near Kenosha, Wisconsin. Tests were conducted on ¼ of the 600MW Unit 2 that fires a variety of Powder River Basin, low-sulfur subbituminous coals. The primary particulate control equipment consists of Research-Cottrell weighted wire cold-side ESPs with sulfur trioxide (SO_3) flue gas conditioning. The specific collection area (SCA) is 468 ft^2/kacfm.

Hopper ash is combined from all four precipitators in the dry ash-pull system. The ash is sold as a cement powder substitute in concrete and is considered a valuable byproduct. Sorbent for mercury control was injected into the ductwork downstream of the SO_3 injection grid. The sorbent had approximately 0.75 seconds of residence time in the duct before entering the ESP. A spray cooling system provided by EnviroCare International was installed upstream of sorbent injection to adjust flue gas temperature.

PG&E NEG Brayton Point Site Description

Brayton Point Station is located in Somerset, Massachusetts. Unit 1 has a tangentially fired boiler rated at 245 MW firing a low sulfur, bituminous coal.

The primary particulate control equipment consists of two cold-side ESPs in series, with an EPRICON flue gas conditioning system that provides SO_3 for fly ash resistivity control. The EPRICON system is not used continuously, but on an as-needed basis. The first ESP (Old ESP) in this particular configuration was designed and manufactured by Koppers. The Koppers ESP has a weighted wire design and a specific collection area (SCA) of 156 ft^2/1000 acfm. The second ESP (New ESP) in the series configuration was designed and manufactured by Research-Cottrell. The second ESP has a rigid electrode design and an SCA of 403 ft^2/1000 acfm. Total SCA for the unit is 559 ft^2/1000 acfm. The precipitator inlet gas temperature is nominally about 280°F at full load.

Hopper ash is combined between both precipitators in the dry ash-pull system. The ash is processed by an on-site carbon separation system, to reduce the carbon content to approximately 2%. This processed ash is sold as base for concrete and is considered a valuable product for the Brayton Point Station. The remainder of the higher carbon ash is a disposable waste.

PG&E NEG Salem Harbor Site Description

Salem Harbor Station is located in Salem, Massachusetts. Units 1-3 fire and use oil for startup. Unit 1 is a 88 gross MW B&W single-wall-fired unit with twelve DB Riley CCV-90 burners firing a low sulfur, bituminous coal from South America.

The particulate control equipment consists of a two-chamber, cold-side ESP, which provides two separate gas flow paths from the outlet of the tubular air heaters to the ID fan inlets. This Environmental Elements ESP has a rigid electrode design and a specific collection area (SCA) of 474 ft2/1000 acfm. The precipitator inlet gas temperature is nominally 295°F at full load. There are eight electrical fields in the direction of flow, and two across. The discharge electrodes are 44.5 feet in length and are spaced 18" apart in the direction of gas flow.

ACTIVATED CARBON INJECTION EQUIPMENT

Activated carbon injection equipment used with an ESP will be designed to feed from 5 to 20 lb/MMacf. A typical carbon injection system consists of a bulk-storage silo and twin blower/feeder trains each rated at 750 lb/hr. PAC is delivered in bulk pneumatic trucks and loaded into the silo, which is equipped with a bin vent bag filter. From the two discharge legs of the silo, the reagent is metered by variable speed screw feeders into eductors that provide the motive force to carry the reagent to the injection point. Regenerative blowers provide the conveying air. A PLC system is used to control system operation and adjust injection rates. Hard piping carries the reagent from the feeders to distribution manifolds located on the ESP inlet duct, feeding the injection probes. Each manifold can supply up to six injectors.

Figure 1 shows two injection lance and nozzle arrays tested at Brayton Point. Tests were conducted to determine if the increased number of nozzles in the second array improved distribution of the sorbent resulting in improved mercury capture. Tests were also conducted to document the effect of co-current and counter-current injection. The results indicated that both lance configurations provided essentially comparable distribution ofthe sorbent resulting in reductions in mercury emissions by up to 90%.

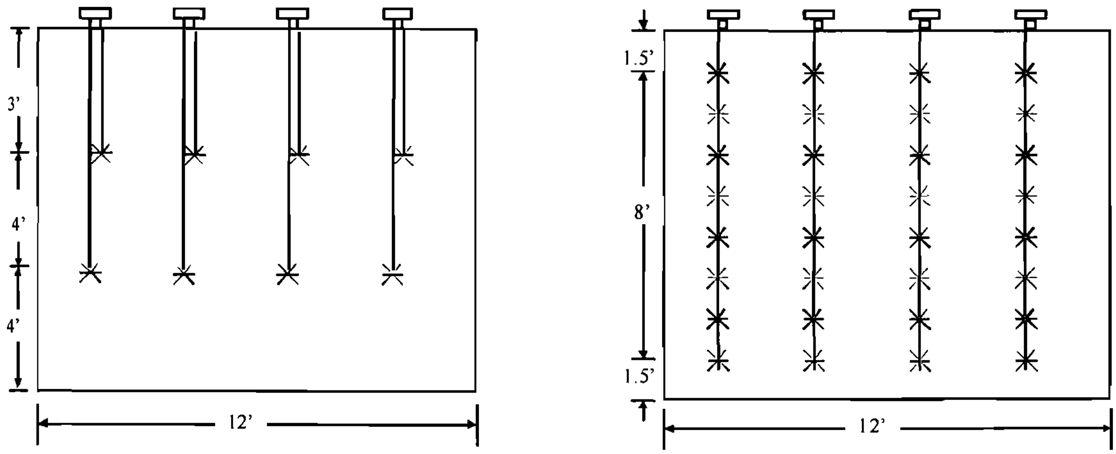

Fig 1. Distribution lance arrays tested at the Brayton Point Station.

DESIGN AND OPERATING CONSIDERATIONS FOR ACTIVATED CARBON INJECTION

Figure 2 presents full-scale data from Brayton Point, burning a bituminous coal, and Pleasant Prairie, burning a Powder River Basin (PRB) coal. For both cases, mercury removal increases with increased rates of carbon injection. For the PRB coal, mercury removal was limited to 70% across the ESP. This limitation is most likely due to the trace amounts (<1 ppm) of HCl available in the gas stream. For the bituminous coal, mercury removal exceeded 90% at the highest carbon injection rate. This coal has a high-chloride content that resulted in approximately 150 ppm of HCl.

Researchers have observed that very low concentrations of HCl in the flue gas is required for standard activated carbon to effectively remove elemental mercury (Sjostrom et al., 2002). The activated carbon sorbent is designed to adsorb contaminants in the flue gas whether they be vapor phase mercury, sulfur dioxides, or gaseous HCl. At Pleasant Prairie, where gaseous HCl concentrations are less than 1ppm, once all of the HCl in the flue gas was adsorbed by the activated carbon, the effectiveness of activated carbon to capture elemental mercury was greatly reduced. This could help explain the apparent ceiling phenomenon observed at Pleasant Prairie where the mercury removal efficiencies did not increase when sorbent injection concentrations increased above 10 lbs/MMacf.

Theory also suggests that oxidized mercury adsorption is not as sensitive to the presence of HCl in the flue gas. At Brayton Point the predominant species of mercury is in the oxidized form, in contrast to Pleasant Prairie where the majority of vapor phase mercury was in the elemental form, and there is a significant amount of HCl present in the flue gas. These two factors create an environment in the flue gas for activated carbon to capture both forms of mercury; oxidized and elemental, at all injection concentrations. Thus, as can be seen in Figure 2, increasing activated carbon injection for bituminous coal results in continuing increases in the amount of mercury capture.

Ontario Hydro measurements were made at both these locations. Table 1 present results from the PRB test site. These tests show that the overall removal was 73% even though the majority of the mercury was in the elemental form. In fact, the collection efficiency was nearly identical for both elemental and oxidized mercury. This test is typical of results from other sites, showing the capability of powdered activated carbon to capture all forms of mercury from both bituminous and subbituminous coals.

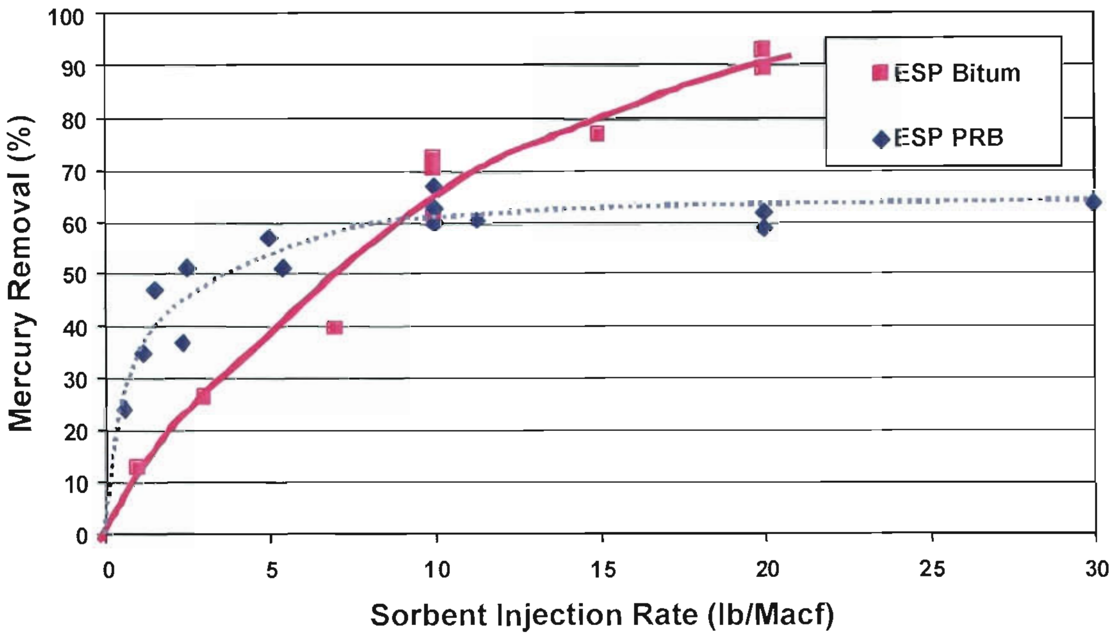

Fig 2. Mercury removal with activated carbon injection upstream of an ESP.

Table 1. Speciated mercury measured by Ontario Hydro Method, long-term tests at PAC injection concentration = 11 lbs/MMacf.

	Particulate (μg/dncm[a])	Elemental (μg/dncm[a])	Oxidized (μg/dncm[a])	Total (μg/dncm[a])
ESP Inlet	1.0	14.7	1.7	17.4
ESP Outlet	0	4.3	0.4	4.7
Removal Efficiency (%)	100	70.7	74.5	72.9

[a] Normal: T = 32°F

Impact of Gas Temperature on Mercury Removal

Analysis of the ICR data showed that mercury capture across ESPs and fabric filters was strongly dependent upon flue gas temperature and unburned carbon levels. It was believed that this phenomenon was due to the fact that while unburned carbon has very low capacity to hold on to mercury, this capacity significantly increases at lower temperatures. For example decreasing the temperature from 300 °F to 250 °F could result in a factor of ten increase in capacity. For this reason, plants with high carbon levels and low temperatures showed the highest mercury capture.

The importance of temperature was expected to diminish somewhat when activated carbon was injected to capture mercury. As shown in Figure 3, activated carbon has a very high capacity to hold onto the captured mercury, in excess of a thousand micrograms of mercury per gram of carbon at temperatures below 300 °F. This represents excess capacity as the carbon is only exposed to the flue gas long enough to capture about one hundred micrograms of mercury per gram of carbon. Since much of the capacity of PAC is underutilized, cooling the gas to enhance the carbon to even higher capacity would be wasted and should not result in better performance.

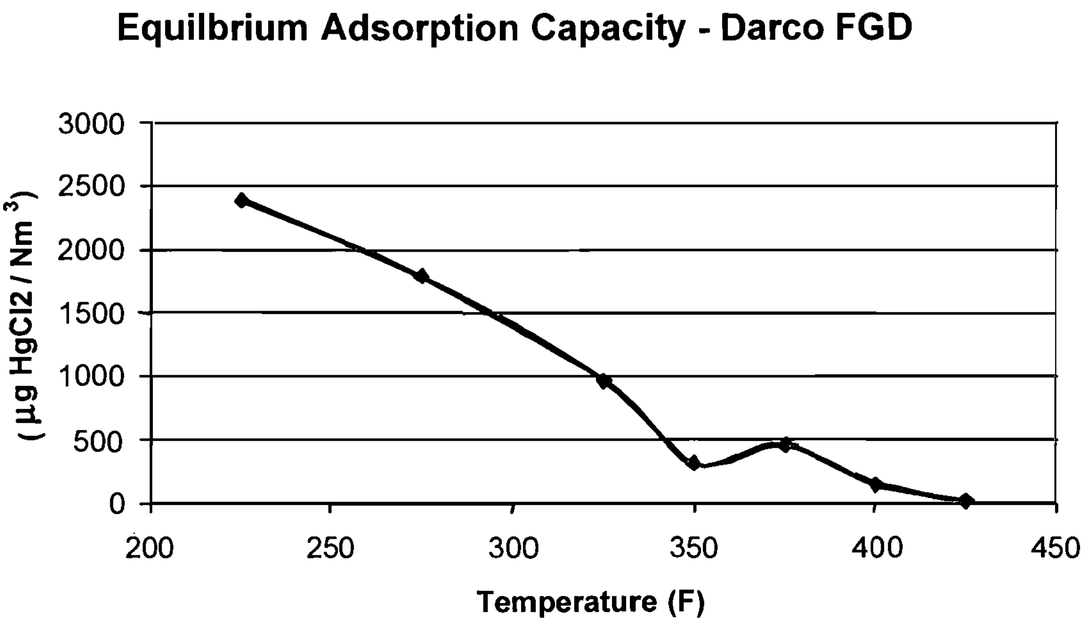

Fig 3. Sorbent adsorption capacity vs. temperature.

The NETL full-scale field tests provided the means to evaluate the role of temperature in mercury removal. A spray cooling system was installed and operated during the Pleasant Prairie tests. The equipment was installed upstream of carbon injection and provided the capabilities of cooling the gas by up to 50 °F. Mercury measurements were made while injecting activated carbon at the normal operating temperature of 300 °F and with the spray cooling system operating to cool the gas to 250 °F. There was no impact on mercury removal with activated carbon from spray cooling. As expected, since the sorbents had a significant amount of excess capacity, increases in capacity at the lower temperature did not result in a change in overall mercury removal.

There was also interest in the impact of higher operating temperatures on both native mercury removal and the performance of activated carbon. At the Salem Harbor Station, placing the steam coils in service could increase temperature by up to 50°F. Under normal operating conditions, ESP inlet temperatures averaged approximately 300°F. Placing the steam coils in service, the average ESP inlet temperature increased to 350°F. These tests were important because the ash produced at Salem Harbor had very high unburned carbon levels, in excess of 30%. This resulted in natural mercury removal levels as high as 90%.

During the parametric test series, the steam coils were placed into service while Unit 1 was held steady at full load (~ 86 MW). ESP inlet temperatures were increased from 300°F to 350°F. The data plotted in Figure 4 show that without injecting activated carbon, the mercury removal by the unburned carbon was extremely sensitive to the gas temperature. For all operating conditions, increasing the flue gas temperature decreased the overall removal efficiency for the vapor phase mercury from ~ 90% to the 10-20% range.

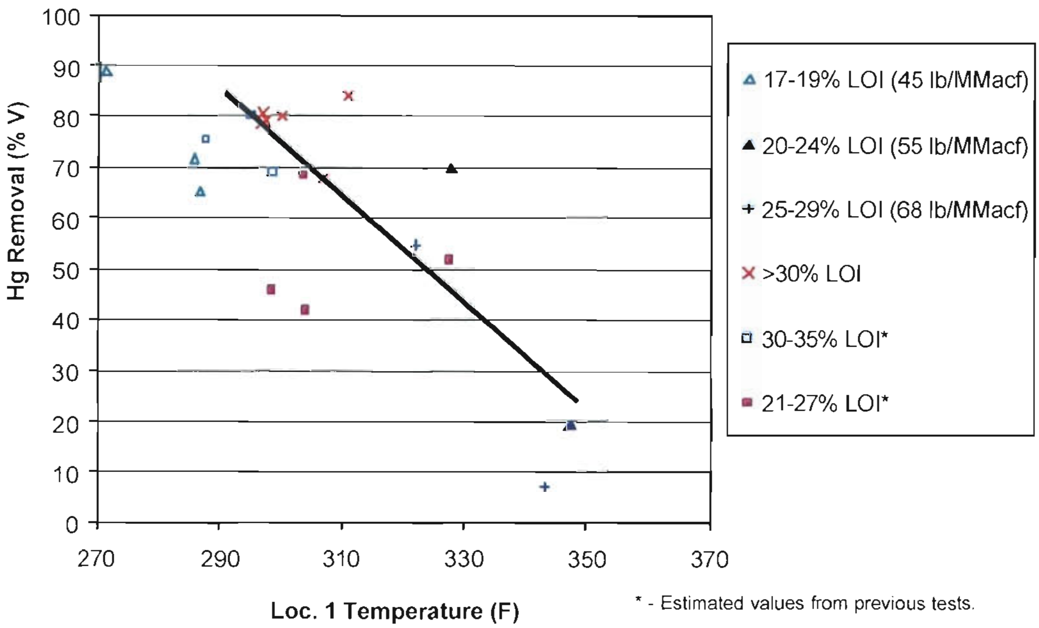

Fig 4. Hg removal efficiency vs. temperature (no sorbent injection).

Temperature can also be important even with activated carbon at very high temperatures. Figure 5 shows a comparison of performance with activated carbon injection at Brayton Point and Salem Harbor. At Brayton Point, removal levels exceeding 90% were achieved with activated carbon at average temperatures of 300 °F. However, at Salem Harbor, at the hotter temperature range of 343-350°F, activated carbon performance was severely impacted and maximum mercury removal efficiency was nominally only 45%. Therefore, some form of cooling may be required for applications where the flue gas temperature exceeds 340°F. Since both of these test sites had predominantly oxidized mercury in the flue gas, it is not known whether the performance of activated carbon on gas streams with predominantly elemental mercury will be as sensitive to temperature. Additional testing on a site burning a Western coal will be required to determine the maximum temperature for effective mercury capture.

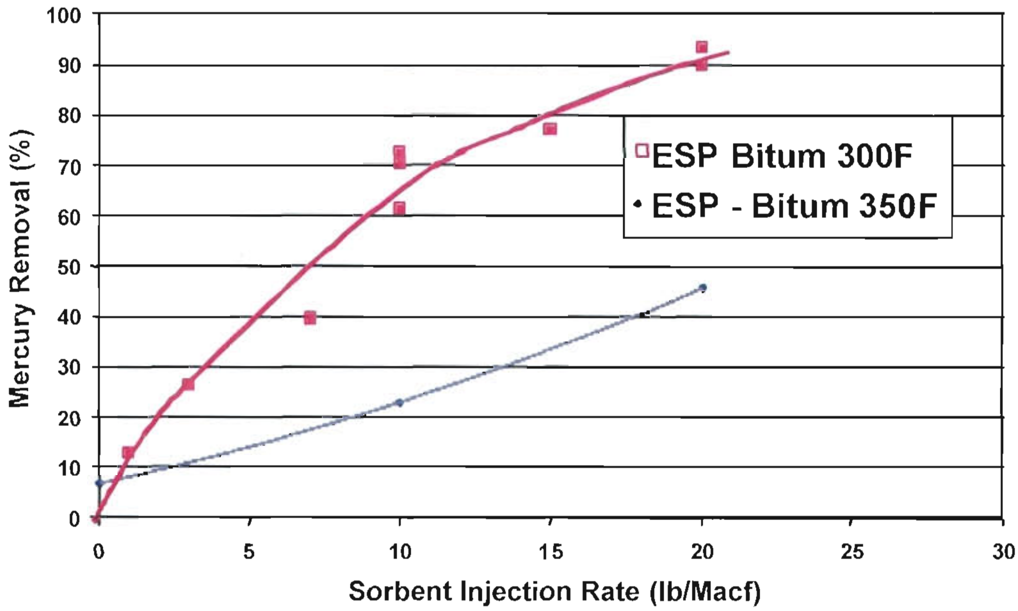

Fig 5. Temperature impacts on the performance of activated carbon on gas streams containing predominantly oxidized mercury.

Sorbent Characteristics

The most commonly used sorbent for mercury control has been activated carbon. For the past two decades, activated carbon injection upstream of a baghouse has been successfully used for removing mercury from flue gases from municipal and hazardous waste combustors. Activated carbon is carbon that has been "treated" to produce certain properties such as surface area, pore volume, and pore size. Activated carbon can be manufactured from a variety of sources, (e.g. lignite, peat, coal, wood, etc.). More commonly, steam is used for activation, which requires carbonization at high temperatures in an oxygen-lean environment. As some carbon atoms are vaporized, the desired highly porous activated carbon is produced. Commercially, activated carbons are available in a range of particle sizes, as well as other characteristics that are needed for a specific application.

At Brayton Point, mercury sorbents from several suppliers were evaluated. The first phase of the sorbent screening process was conducted by URS Corporation using a fixed bed of carbon to measure the sorbents mercury adsorption capacity. The mercury adsorption tests were carried out on a slipstream of flue gas extracted from upstream of the first precipitator, with and without SO_3 injection. Eight coal derived sorbents, two fly ash, one tire derived sorbent, and one zeolite based sorbent were each tested at a temperature of 275°F. The major conclusions from the fixed-bed tests were:

- Carbons are capable of achieving high mercury capacities in Brayton Point Unit 1 flue gas;
- SO_3 appears to inhibit carbon adsorption and with certain sorbents decreased the adsorption capacity to zero. With the activated carbon products, the presence of SO_3

in the flue gas decreased the adsorption capacity in some cases by a factor of six, however the measured adsorption capacity was still above the threshold capacity (nominally 150 μg/g for an ESP). Therefore performance of these sorbents should not be impacted;

- Only one of the fly ash based sorbents tested showed an adsorption capacity greater than 150 μg/g; and
- The zeolite based sorbent showed a low adsorption capacity in the Brayton Point flue gas, thus, this particular sorbent was not chosen for full-scale testing.

Using the results from the fixed-bed tests as one of the selection criteria, five activated carbon sorbents were selected for the full-scale test. A series of parametric tests was conducted to determine the optimum operating conditions for several levels of mercury control. During this particular series, the primary variables that were tested included injection concentration, sorbent type, and SO_3 flue gas conditioning on/off. Standard testing conditions were with Unit 1 boiler at full load operation and the EPRICON flue gas conditioning system on. Each condition was tested for a minimum of six hours, or until a state of equilibrium had been reached.

A summary of results from all the parametric tests is presented in Figure 6. It is important to emphasize that this graph represents the mercury capture across the second ESP. This is incremental mercury capture that is being measured independent of the baseline mercury capture that is happening across the first ESP. The different symbols represent different sorbents. This graph shows that all sorbents showed the same trends, which included a direct relationship between the Hg removal efficiency and sorbent injection concentration. Because of the short duration of the tests and the difficulty of the mercury measurements, we can only conclude that there are several high capacity activated carbons capable of effective capture of mercury from coal-fired flue gases.

Impact on ESP Performance

There are two issues related to the impact of activated carbon injection on the downstream ESP. The first is the impact on the bulk properties of the ash collected on the plates. A change in the overall resistivity of the material could result in a significant degradation of the performance of the ESP. However, at all three test sites with ESPs, there was no change observed in the fundamental operation of the ESP. As an example, Figure 7 shows a plot of the ESP power before and during the injection of activated carbon at Brayton Point. Even at injection rates up to 20 lb/MMacf, there was no observable change in ESP operation. Similar results were also experienced at Pleasant Prairie and Salem Harbor.

The second issue is whether the easily reentrainable carbon can be effectively captured in the ESP. Measurements of both particulate emissions and opacity were made at all three test sites. These measurements indicated that there was no increase in emissions during any of the test programs. This would not be unexpected in that the activated carbon represented an increase of only 1-2% in the inlet particulate loading. In addition, the activated carbon had a mass median diameter of 17 micrometers so the particles would not be difficult to capture.

One caveat is that all three ESPs were relatively large with specific collection areas in excess of 450 ft^2/kacfm. Additional testing will be required to document capture in smaller ESPs.

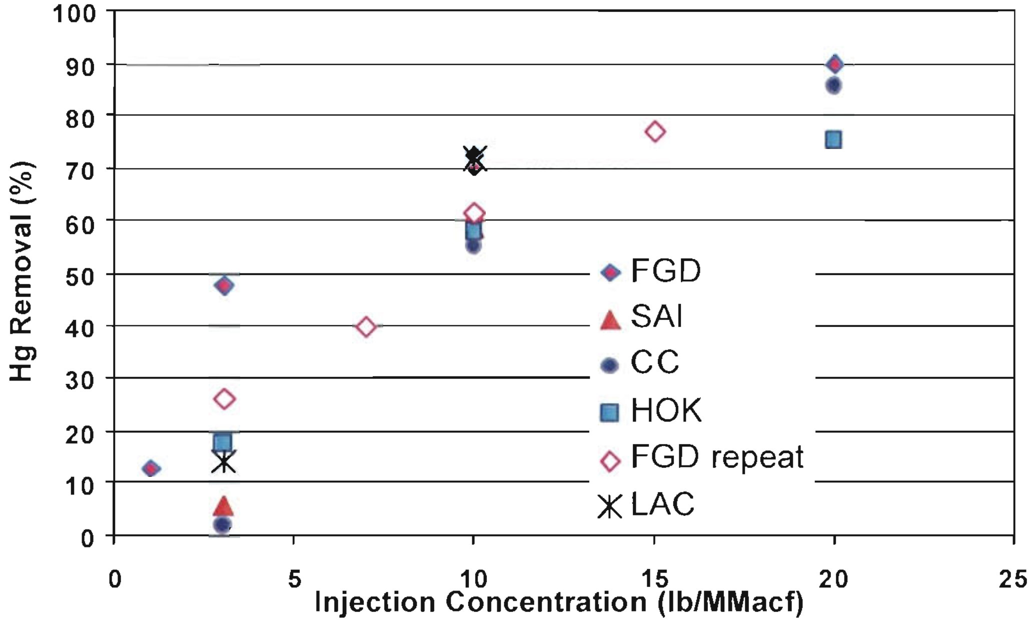

Fig 6. Performance of activated carbons from different suppliers at Brayton Point.

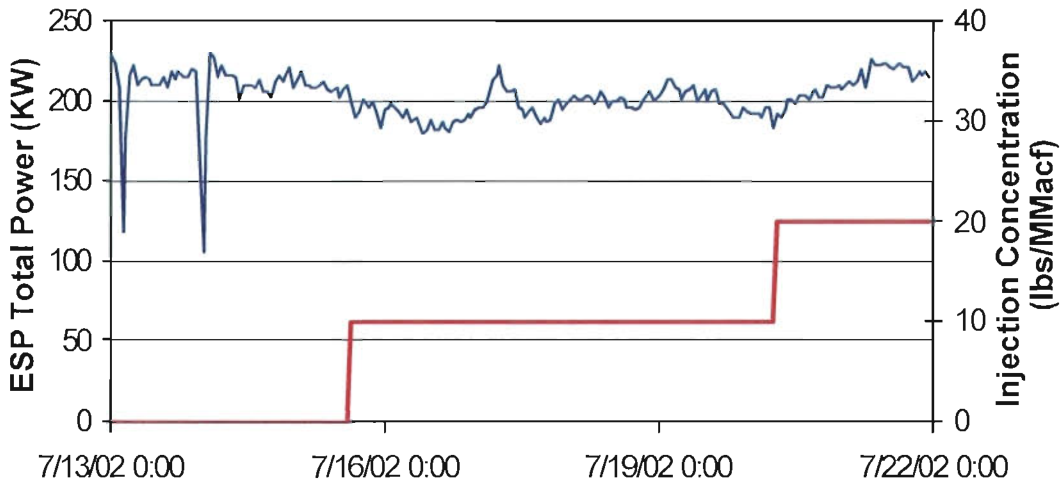

Fig 7. ESP power during injection of activated carbon at Brayton Point.

Residence Time Required for Mercury Removal

One key issue to be considered in the retrofit application of activated carbon injection to a large number of plants is whether there will be sufficient residence time available upstream of the ESP for the sorbent to react with the mercury. This question has two components with the first dealing with the amount of time required for the reaction. During the Brayton Point test program, an additional CEM measurement location was added to be able to determine how much of the mercury reacted with the sorbent before entering the ESP. The distance between the sorbent injection location and the CEM location in front of the ESP was approximately 24 feet. This allowed for a residence time of < 0.5 seconds for reaction between the activated carbon particle and the gaseous mercury.

Figure 8 shows a comparison of the removal of mercury as measured across the entire system (i.e. inlet ducting and ESP) with that measured in the ducting alone. As can be seen, it appears from this data that a majority of the capture occurs in-flight upstream of the ESP. The capture of up to 90% of the mercury in-flight is less than a half of a second was much faster than the model predicted. To insure that this was not a measurement artifact, the data was analyzed to determine if the results could be explained by a build up of carbon in the inlet probe. However, it could be seen that the mercury concentration dropped almost immediately upon initiation of carbon injection, and returned when injection was ceased. This confirmed the speed of the reaction with activated carbon, at least for oxidized mercury. Similar tests on a stream containing predominantly elemental mercury will be needed to determine the time necessary for acceptable performance.

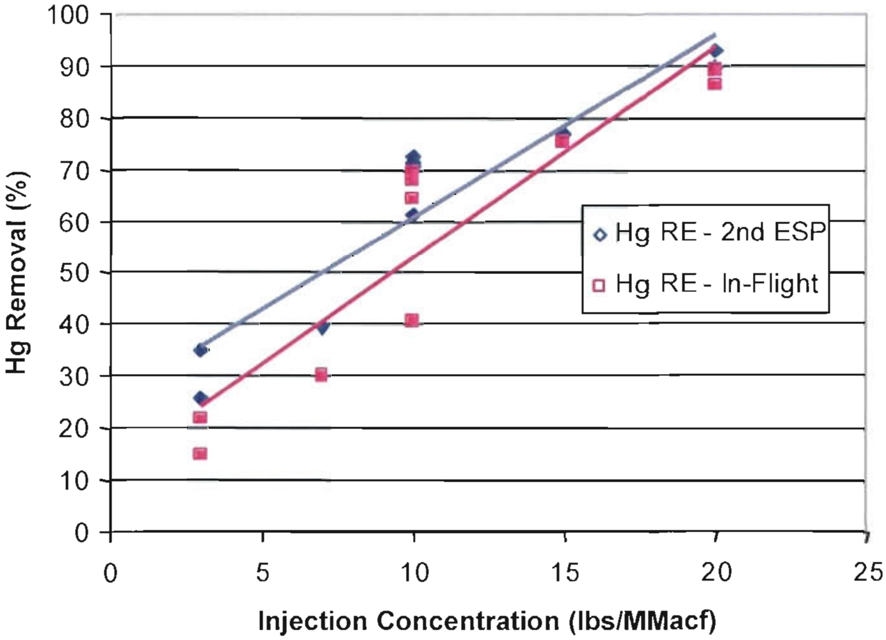

Fig 8. Comparison of mercury removal measured "in-flight" and across the ESP.

The second component of the residence time issue is the total amount of time available for carbon and mercury interaction in the system. One key point is that the in-duct residence time represents the smallest of the three components of residence time available for a reaction between an injection sorbent and mercury in the flue gas. In addition to the ducting upstream of the ESP, additional residence time is available in the ESP inlet cone and the ESP chamber.

Table 2 shows a comparison of the residence time available in these three areas for the three test sites in this program. As can be seen, the ESP cone provides time for reaction that is two to three times as long as that available in the ducting. Greater time is available in the ESP, but much of this cannot be considered because of the removal of the carbon in the front fields of the ESP. However, because of the fast reaction between the mercury and the activated carbon, and the time available in the ducting and the ESP cone, there should be sufficient time for the process to perform in a large number of plants.

Table 2. Total residence time for interaction between activated carbon and mercury

Plant	In-Duct (Sec.)	ESP Cone (Sec.)	ESP Box (Sec.)
Brayton Point	0.54	1.5	12
Salem Harbor	0.9	1.6	18
Pleasant Prairie	0.75	3.1	14.7

Impact of Selective Non-Catalytic Reduction (SNCR)

Minimal data are available to assess the affect of SNCR on mercury capture, and there is some debate in the industry as to its potential effectiveness. Salem Harbor's Unit 1 utilizes a urea based SNCR system to help reduce NO_x emissions. With permission from Massachusetts Department of Environmental Protection (MADEP) along with plant personnel, Salem Harbor's Unit 1 operated at full load (~ 86 MW) without the SNCR system upon start-up from a week long outage. This would ensure the system was free of any residual ammonia and help quantify the impacts of SNCR on mercury capture.

During the period in which Unit 1 operated without the SNCR system, vapor phase mercury measurements were made throughout the system with the S-CEM. With the SNCR system out of service, vapor phase mercury removal efficiencies ranged from 80-95%. Mercury removal efficiencies were consistently high throughout this particular test and there was no decrease in mercury removal when SNCR was turned on.

MERCURY IN COAL COMBUSTIONS BYPRODUCTS

Since the purpose of controlling emissions from coal-fired boilers is to reduce potential buildup of mercury compounds in lakes and streams, the stability of mercury captured is a critical component of the overall control scheme. This includes the 30 tons/yr that is currently leaving the plant with coal-combustion byproducts (CUBs) as well as the additional 20 to 40 tons/yr that would be added as a result of mercury control regulations. In addition, there is a concern over the impact of powdered activated carbon in ash being sold for use in concrete.

In the US, approximately 67% of all fly ash produced from utility coal combustion is disposed of in landfills or surface impoundments. The remaining 33% is used for a variety of commercial applications. There are approximately 600 waste disposal sites for CUBs in the US, half are landfills and half are surface impoundments. Note that here CUBs include other streams such as bottom ash and scrubber sludge. A 1999 EPA study estimated that about half of the CUB landfills and a little less than a third of the surface impoundments have some type of liner, the most common type being compacted clay (Senior et al., 2002).

Volatilization of mercury from landfills was estimated by EPA to be small. To date, there has been no evidence based on laboratory leaching studies for leaching of large amounts of mercury from fly ash under landfill conditions. Leaching appears to be the most likely pathway for liberation of mercury from fly ash. Volatilization may be important for certain applications of fly ash as filler in concrete applications. Volatilization is, of course, the primary pathway for mercury if fly ash is used as a raw material in cement kilns. However, volatilization will be complete in this case.

PAC-injection applied to coal-fired boilers will result in the fly ash being mixed with a certain amount of mercury-containing sorbent. This material will be sent to land disposal or used in specific applications (assuming that the presence of the sorbent is compatible with the application). Since the mercury on the spent sorbent may be present in a different form than on fly ash, it is necessary to consider what might be the most likely routes for release of mercury in sorbent-fly ash mixtures and how sorbent-containing coal utilization byproducts (CUBs) should be tested.

Senior et al. (2002) evaluated samples of ash with PAC from two ADA-ES field demonstration programs. The Gaston sample (the product of a bituminous coal) had a high LOI and mercury content, in spite of the low sorbent injection rate, because most of the ash was removed upstream of the COHPAC baghouse by a hot-side ESP. Thus the sample had a relatively high proportion of sorbent. The Pleasant Prairie sample (the product of a subbituminous coal) had a low LOI and mercury content. Sorbent was injected upstream of an ESP and was combined with the full ash stream. The LOI and mercury content were much lower than the Gaston sample. Little or no detectable Hg leached by ASTM water leach, TCLP, SGLP (including 30- and 60-day leaching), sulfuric acid leach (bituminous ash). Samples were also analyzed by CONSOL as part of a DOE program. They also found no leaching of mercury from PAC (Withum et al., 2002).

Although the ash with PAC appears to be highly stable, initial testing with a PRB ash determined that the presence of even trace amounts of activated carbon in the ash rendered the material unacceptable for use in concrete. Even though the Pleasant Prairie (PRB) ash conformed to the ASTM C-618 standard for Class C fly ash, it did not pass the Foam Index test that is also required for sale of this ash for use in concrete formulation. These are field tests used to determine the amount of Air Entrainment Additives needed to meet freeze thaw requirements. This means that with PAC injection, the plant would not only loose revenues from ash sales, it would incur additional expenses to land fill the material.

CONCLUSIONS

The power industry in the US is faced with meeting new regulations to reduce the emissions of mercury compounds for coal-fired plants. These regulations are directed at the existing fleet of nearly 1100 existing boilers. A reliable retrofit technology is needed for these plants that minimizes the amount of new capital equipment while providing continued flexibility in fuel selection.

Recent full-scale field tests have proven the effectiveness of activated carbon injection (ACI) for reducing mercury emissions. This technology is ideally suited for use on existing coal-fired boilers as it provides the following advantages:

- Minimal capital cost of equipment (<$3/kW);
- Can be retrofit with little or no downtime of the operating unit;
- Effective for both bituminous and subbituminous coals;
- Can achieve 90% removal when used with a fabric filter; and
- It can be integrated to enhance mercury capture with virtually every configuration of air pollution control equipment including ESPs, fabric filters, wet and dry scrubbers.

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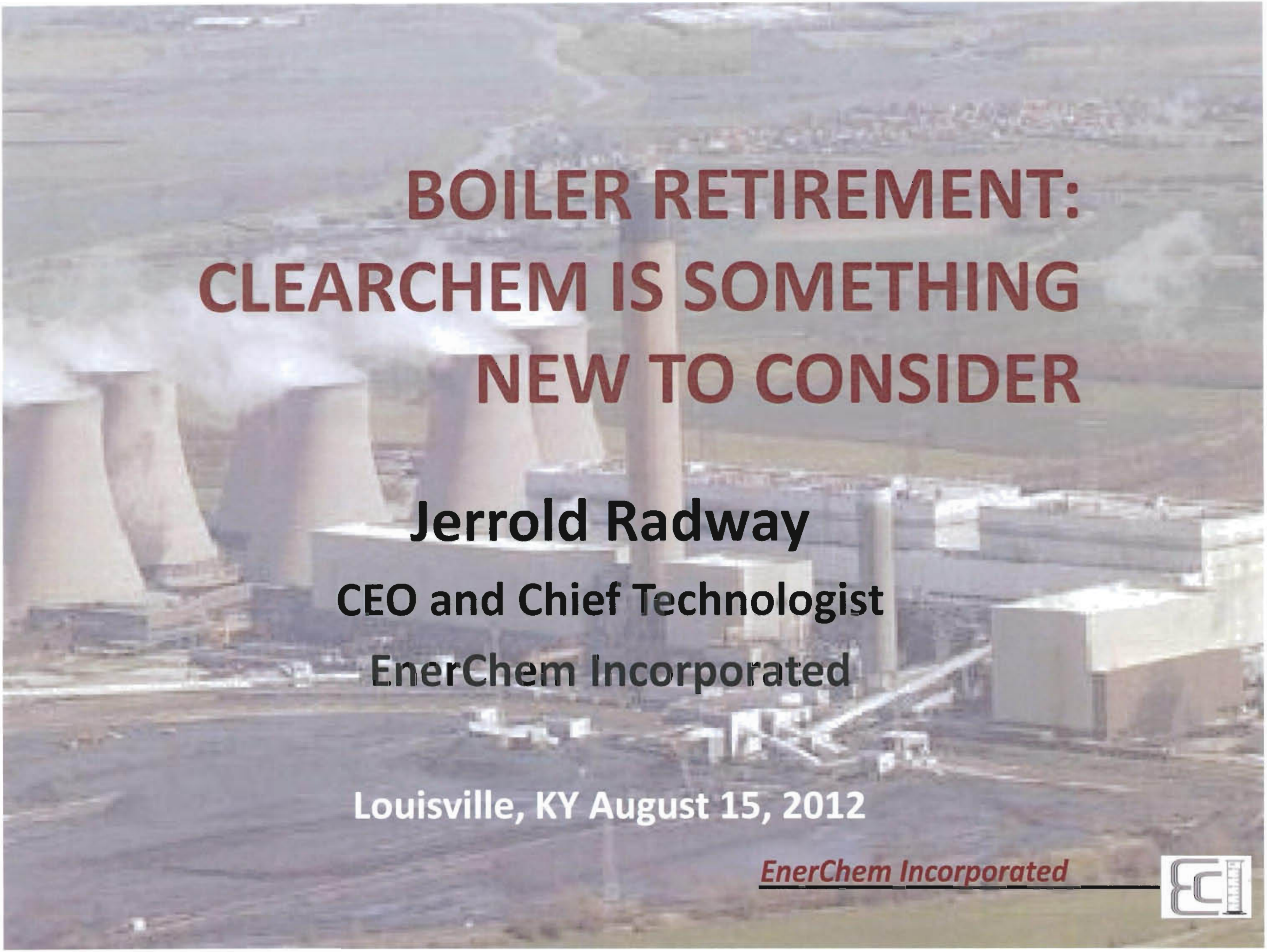
Attachment B

Boiler Retirement – Something New to Consider

Jerrold Radway
EnerChem Incorporated

Louisville, KY August 15, 2012



BOILER RETIREMENT: CLEARCHEM IS SOMETHING NEW TO CONSIDER

Jerrold Radway

CEO and Chief Technologist

EnerChem Incorporated

Louisville, KY August 15, 2012

What is ClearChem (TM)?

- Furnace sorbent injection process
- Patented, based on micronized reagents, $CaCO_3$, $CA(OH)_2$, fly ash and industrial byproducts as powders or high solids dispersions
- Small footprint – simple Hardware
- Very low cost

What are ClearChem effects?

- Effective scavenging of SO_2, SO_3, and HCL
- High surface for capture of oxidized Hg
- Minimal tube deposits and impact on ESP
- Marketable dry ash – no pond leaching
- Allows lower exit gas temps and benefits

ClearChem Is New FSI Technology

- Decades old attempts at furnace sorbent injection (FSI) showed mixed results at best
- ClearChem is different – it solves past issues to release the promise of FSI:
  - Sub micron reagent particles avoid deposits
  - Computer Modeling assures proper distribution
  - Burner zone injection for longer reaction time
  - Better reagent utilization avoids ESP issues

ClearChem Versus Old FSI

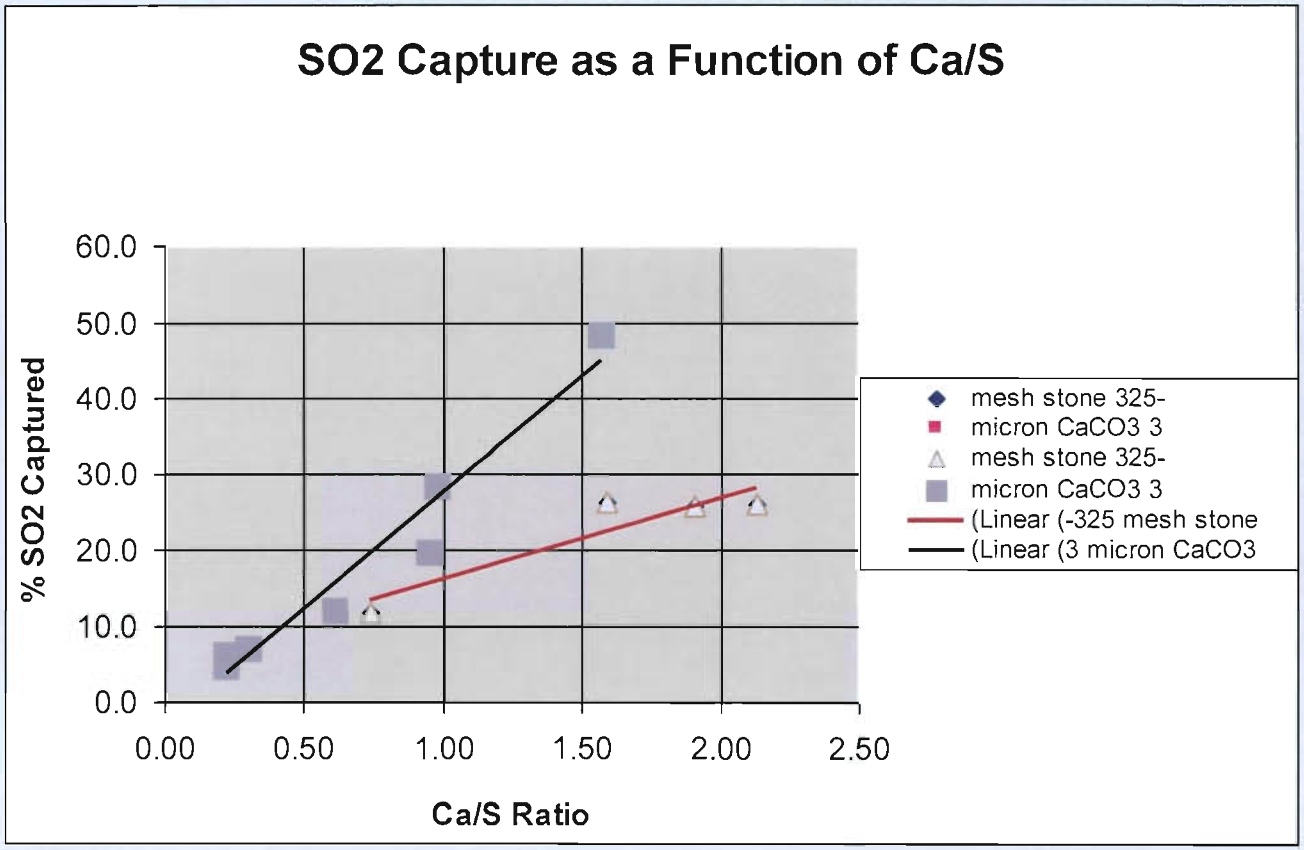
ClearChem	Old FSI
70-84% SO_2 captured	30-50% SO_2 captured
Less than 2 Ca/S	More than 2 Ca/S
Normal soot blowing	Continuous soot blowing
Modest increase in ESP ash burden	Massive increase in ESP ash burden

Results of Pilot and 3 Short Boiler Trials

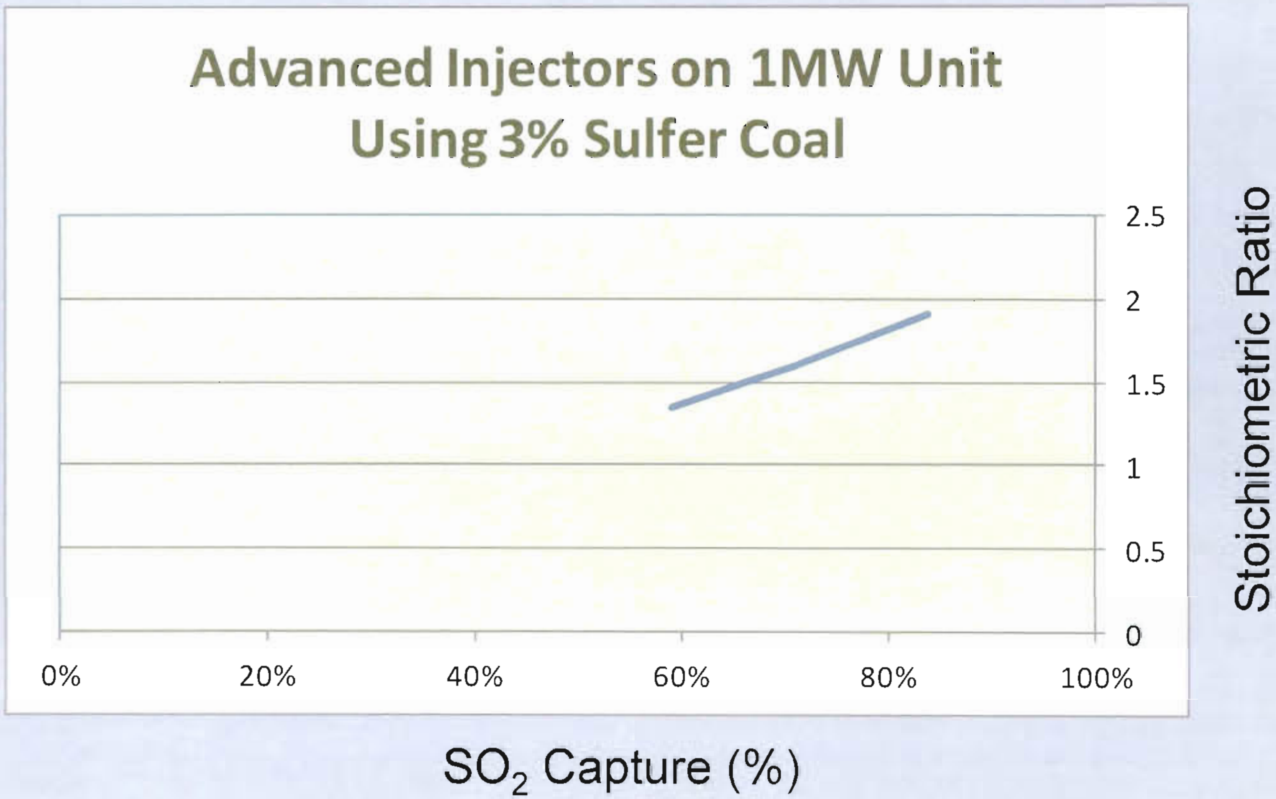
- 84% SO_2 capture at Ca/S =1.9
  - Lower exit temp will boost capture
- HCl capture circa 75%
- SO_3 virtually all captured
  - Allows lower exit gas temp, heat rate, CO_2 release

65 MW Coal Fired Utility boiler

3 micron vs. – 325 mesh powders



Results of Advanced Injector Tests



Why is ClearChem More effective?

- Surface Area of 0.5 micron reagent is mostly external and 88 times that of 325 mesh
- Number of particles per lb of 0.5 micron reagent is 676,000 times that of 325 mesh
- Result: The probability of a reagent particle finding the scarce pollutant molecules in the huge volumes of flue gas is much greater

Costs and Benefits

- Capital cost: starting under \$500,000/unit
- Operating cost: \$400 – 600/ton SO_2 mitigated
- Safe, widely available, easily handled reagents

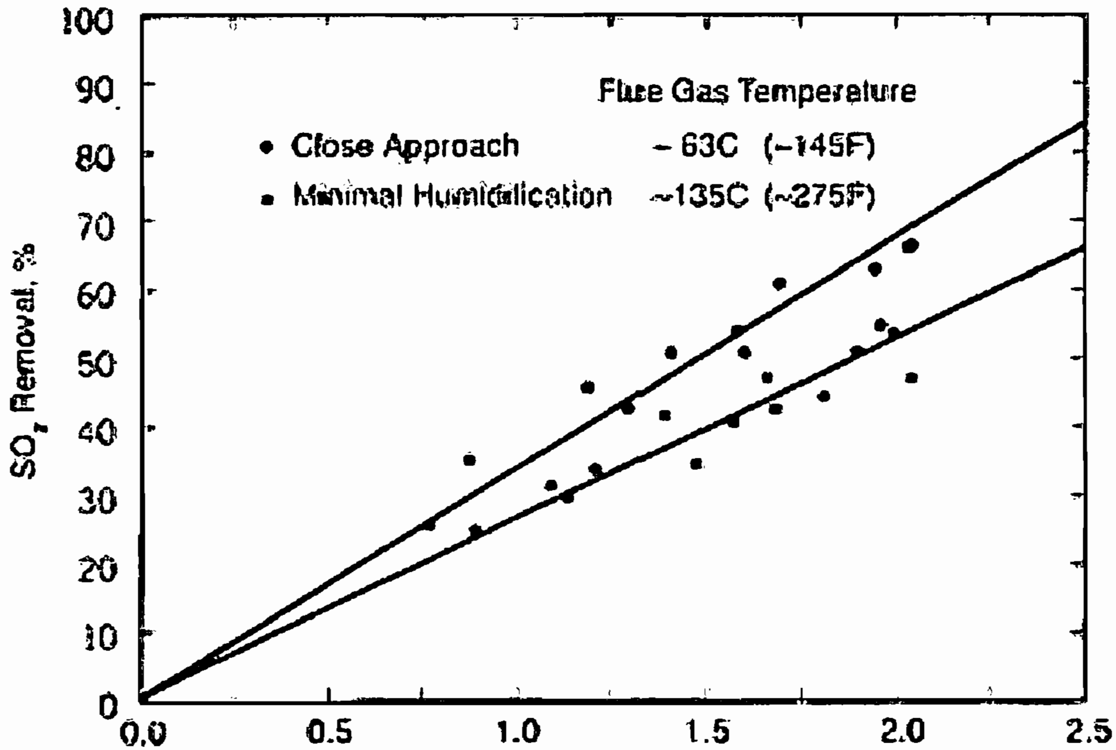
Additional Benefits

- Can make existing FGD more effective
- SO_3 removal eases oxidized Hg capture
- Existing $CaCO_3$ supply can be used
- Improves economics of flue gas H_2O recovery – nearly ton/ton coal – more on scrubbed units

Costs Can Be Reduced Further

- By capitalizing on SO_3 capture to lower flue gas temp – (investment required)
  - Improve unit heat rate – reduce CO_2 emission
  - Recover water from flue gas
- By enhancing reagent capture efficiency via
  - Lowering flue gas temperature - proven
  - Improving injector performance - projected
  - Utilizing byproduct or waste reagent – projected

EFFECT OF FLUE GAS COOLING ON SO2 CAPTURE

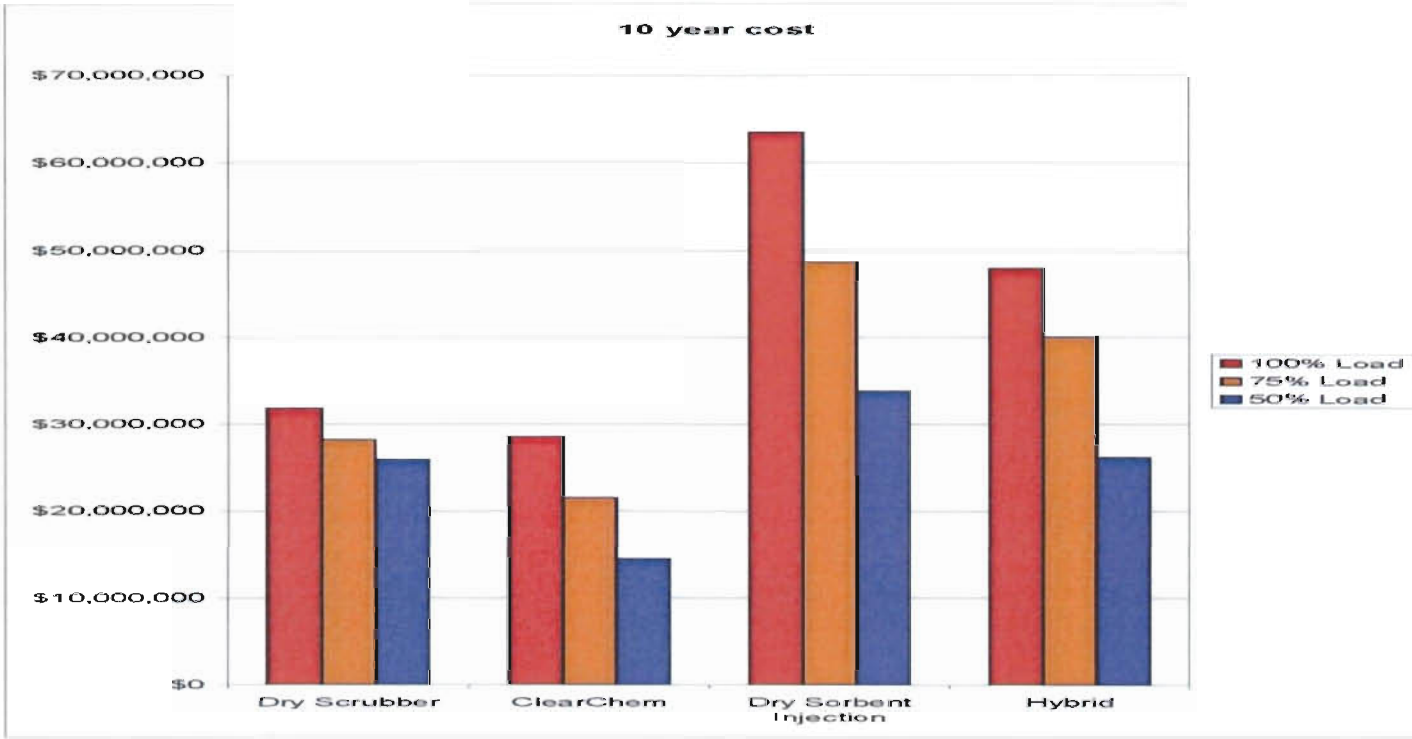


DOE Boiler Trials Using 325 Mesh Limestone Powder

Best Fit Solution

- ClearChem is the optimal solution for plants seeking to control costs associated with emissions control
  - Lower exit temps to enhance pollutant capture
  - Use less costly construction materials
  - Facilitate smaller less costly hardware
  - Makes DSI more cost effective
  - Maintains ash marketability – avoid pond leach

Comparative Cost Over Time



ClearChem vs. DSI

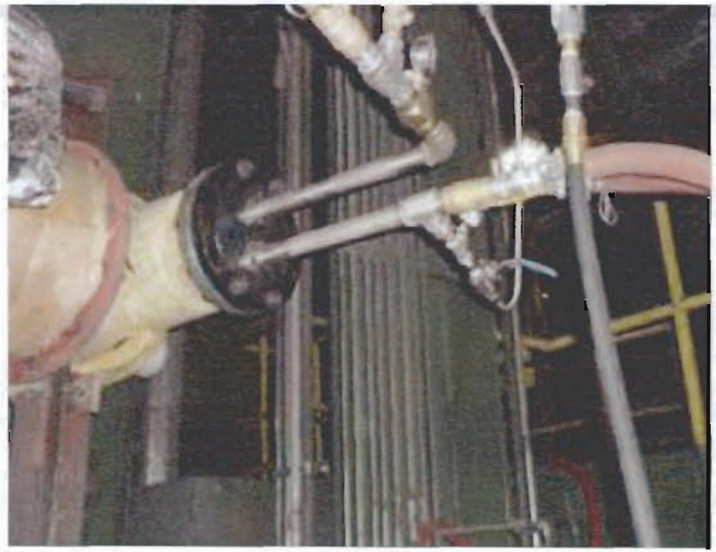
	ClearChem	DSI
SO_2 Capture	70-84%	30-80%
Stoichiometric Ratio	Under 2	Over 2
Lbs/lbs SO_2	3.13	4.82
Application	dispersions	powder
Application Point	burner/nose	econ/ESP
Install Time	3-6 months	6-9 months
Costs, Capital	$400,000	$4,000,000
Reagent	$435-$802/ton less SO_2	$1020-$1632/ton less SO_2

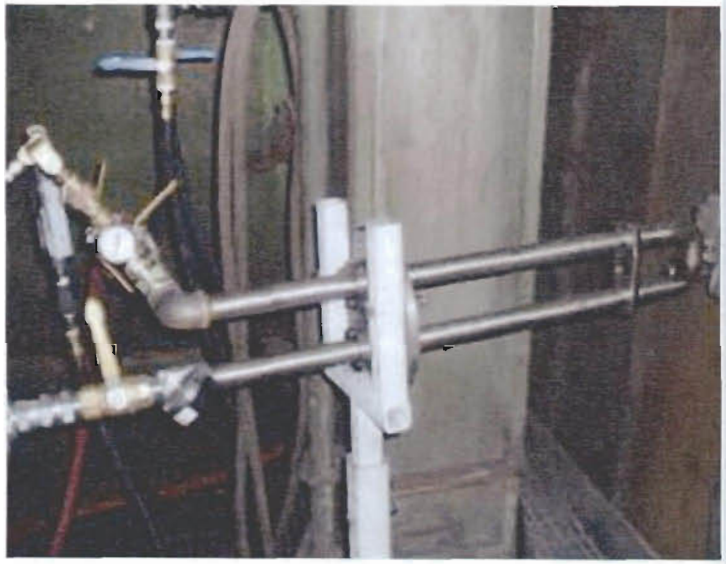
ClearChem vs. DSI

	ClearChem	DSI
Ash marketable	Yes	Yes/No
ESP impact	No (3 demos)	Yes/No
Reagent supply	Mostly local	More remote
Reagent handling	Easy	More labor
Safety & corrosion	No	Yes
Landfill leaching	No	Yes/No
Furnace deposits	Minor	None

Company Status

- US Patents received and pending
- Three short (1 to 2 weeks) boiler trials completed
- First licensing agreements complete for reagent and applicator partners
- Preparing for large scale demonstration under utility operating conditions (1^{st} half 2013)
- International patents pending
- Extending licensing partnerships to additional geographies
- Preparing an equity raise of $3-5 million





CFD modeling indicates best injection sites (2 nozzles at each of the OFA and Side Door ports). Above shows the pump skids and day tank.

Conclusions

- ClearChem has the potential to lower emission control costs across the board
  - Costs low enough to compete with retirement
  - Less expensive way to upgrade FGD systems
  - Reduce DSI operating costs
  - Practical way to control SO_3 & reap benefits
    - Reduce fuel consumption and CO_2 emissions
    - Recover H_2O from flue gas
    - Eliminate "blue plume"

IMPACTS OF HYDRATED LIME INJECTION
ON ELECTROSTATIC PRECIPITATOR PERFORMANCE

ASTM Symposium on Lime Utilization

June 28, 2012

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ABSTRACT

Electrostatic precipitators (ESPs), which are particulate collectors, are now used as part of the flue gas scrubbing strategy. In these combined systems, hydrated lime is injected into the flue gas ahead of the ESP, to either neutralize or adsorb a gaseous pollutant. Then the ESP must remove the combined fly ash from fuel combustion, plus the unreacted reagent and reaction products.

The primary parameter in ESP performance is the particulate resistivity. Particulate resistivity is a measure of how well the particulate, when deposited on the ESP collecting electrodes, conducts electricity to ground. Variations in resistivity from optimum to extremely high can change ESP particulate emissions by significant amounts. When injecting hydrated lime into the flue gas, we must be very concerned with the impacts of injected lime and reaction products on combined particulate resistivity in the ESP. Resistivity will have a greater impact on ESP performance than all other parameters combined.

This paper is a study of the impacts on resistivity from injecting hydrated lime to treat flue gas. Lime and some of its reaction products are known to be somewhat high in resistivity, and its addition to the fly ash could be a concern in performance modeling. The impact of typical lime injection rates will be analyzed for impacts on fly ash resistivity. In addition, the paper will also discuss the impacts of these resistivity changes on ESP particulate emissions.

RESISTIVITY INTERPRETATION

Laboratory resistivity (OHM-CM) of a dust is the ratio of the applied electric potential across the dust layer to the induced current density. The value of the resistivity for a dust sample depends upon a number of variables, including dust chemistry, dust porosity, dust temperature, composition of gaseous environment (i.e. gas moisture), magnitude of applied electric field strength, and test procedure.

In working with electrostatic precipitators (ESP), resistivities are encountered in the range from about 1E4 to 1E14 OHM-CM. The optimum value for resistivity is generally considered to be in the range of 1E8 to 1E11 OHM-CM. In this range the dust is conductive enough that charge does not build-up in the collected dust layer and insulate the collecting plates. Additionally the dust does not hold too much charge and is adequately cleaned from the collecting plates by normal rapping. If resistivity is in the range 1E12 to 1E14 OHM-CM, it is considered to be high resistivity dust. This dust is tightly held to the collecting plates, because the dust particles do not easily conduct their charge to ground. This insulates the collecting plates and high ESP sparking levels result (also poor ESP collection efficiencies). Conversely if the dust is low resistivity, 1E4 to 1E7 OHM-CM, the dust easily conducts its charge to the grounded collecting plates. Then there is not residual charge on the low resistivity dust particles to hold them on the plates. Thus these particles are easily dislodged and re-entrain back into the gas stream. ESP gas velocities are generally designed in the 2.5-3.5 FT/S range, if high carbon particles are to be collected. There are a number of publications that provide a depth of discussion on the resistivity impacts on the operation of ESPs [1,2,3,4].

In looking at resistivity data, the resistivity of particulates is temperature dependent and "curves" generally peak out in the range of 280-360 F. On the high side of the peak, thermal conduction effects cause the resistivity to decrease as temperature increases. On the cold side of the resistivity peak, condensation of moisture on the surface of the particulate causes the resistivity to decrease as well.

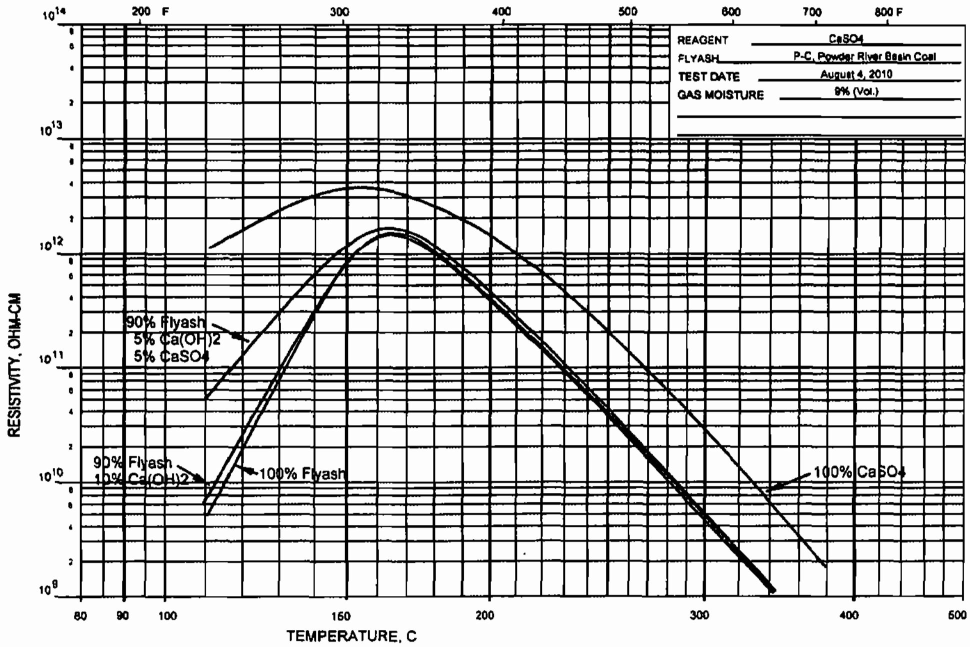
The laboratory resistivity testing in this paper was done strictly with humidity for surface conditioning. So these laboratory measurements in this report are for fly ash, hydrated lime, and potential reaction products only. In the actual flue gas (especially with high sulfur content fuels) there will be surface conditioning from sulfuric acid, which could reduce the particulate resistivity down to even lower values than shown in this report. However, in most cases the fly ash from high sulfur coal contains relatively low levels of dielectric (i.e. silica+alumina+CaO). So there is never a situation where we have anything but a good resistivity predicted for any of the high sulfur fuel cases. Therefore no matter what sorbent we inject with high sulfur coal, we have good resistivity before and good resistivity after injection.

CALCIUM HYDROXIDE INJECTION

The chemical formula of calcium hydroxide is Ca(OH)2. Of primary importance to resistivity measurements, is that this material contains calcium. In the ESP industry, calcium compounds (CaO, $CaSO_4$, $CaCO_3$) have been observed for many years to be highly resistive. In these ESP uses involving high amounts of calcium compounds, such as cement plants, the resistivity of the calcium compounds has been controlled by injecting moisture and operating on the cold side of the resistivity peak.

In recent years, the $Ca(OH)_2$ is being injected as a reagent for gaseous scrubbing purposes. But at the same time this hydrated lime and its reaction products must be collected by the ESP. Note that at the ESP, some of the calcium may exist as reagent, $Ca(OH)_2$, and some as a reactant, such as $CaSO_4$. To better understand the impacts of this injection, resistivity studies were undertaken with both Powder River Basin sub-bituminous fly ash and Eastern high sulfur bituminous fly ash. The results of resistivity tests for PRB coal are shown on Figures 1;

Figure 1

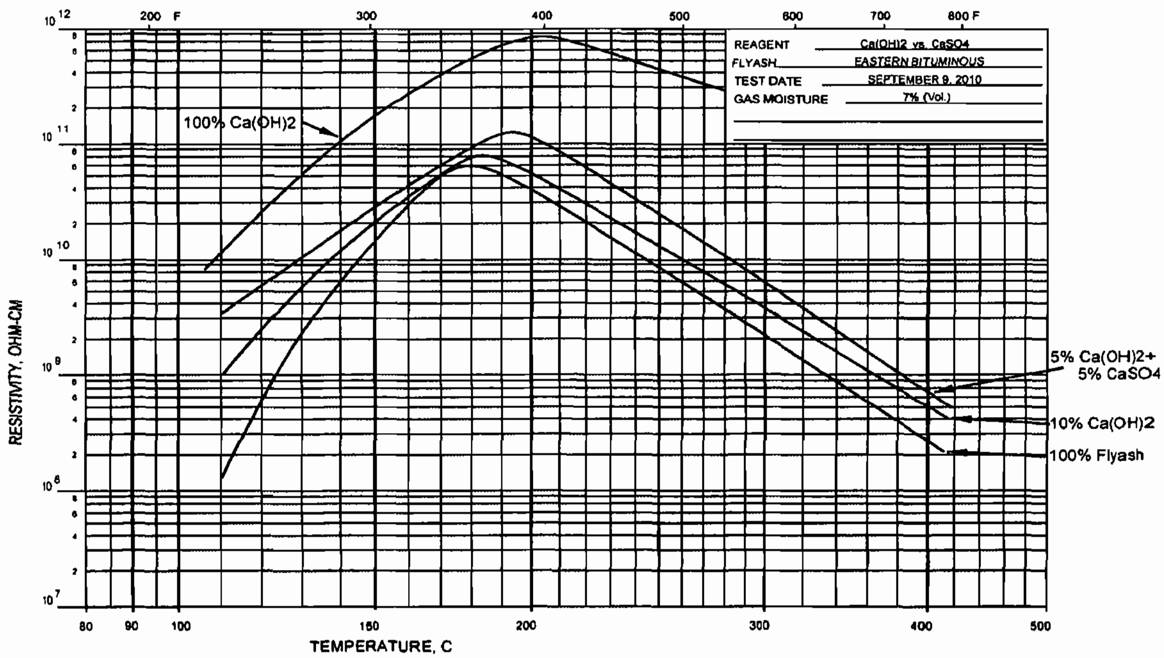


There are several things to note on Figure 1. First the resistivity of the 100% PRB fly ash was in the high range (i.e. >1E12 OHM-CM), which on its own would cause difficulty for ESP performance. Then tests of 100% $CaSO_4$ showed the resistivity to "peak out" even higher at 4E12 OHM-CM. This is a high/bad value for electrostatic precipitation. So as expected, the pure calcium reaction products can be very high in resistivity. With any cases of very high injection rates vs. fly ash rate, there could be a negative impact on resistivity/ESP performance.

However, the typical injection rate for $Ca(OH)_2$ injection is in the 10% reagent to 90% fly ash range. In this more dilute case, the combined flyash/reagent resistivity is hardly impacted by the injection. This means that really the only impact on the ESP would be from a 10% higher inlet dust loading coming to the ESP. Inlet loading is a much less powerful impactor on ESP performance than resistivity. This is especially true in this case, where the particle size of the injected reagent is created from milling. It is typical for the particle size from pulverized-coal firing to be much finer. This is because the particle size of fly ash is created by milling and then burning off of the carbon in the coal. Therefore the $Ca(OH)_2$ impact in this case would depend on ESP design and sizing. If the ESP is conservative (i.e. properly designed for high resistivity), the prediction would be very little increase in particulate emissions in this case.

Fly ash from high sulfur Eastern bituminous coal is quite different in resistivity from PRB fly ash. Figure 2 shows tests for the Eastern coal fly ash;

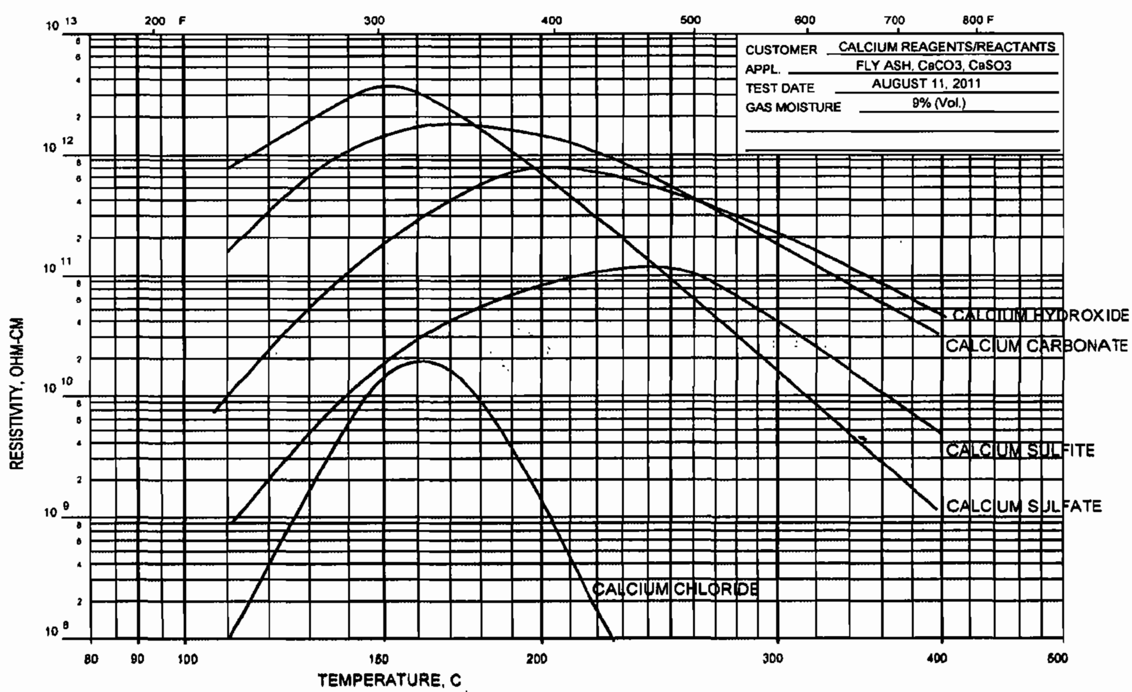
Figure 2



On Figure 2, we can note that the bulk resistivity of 100% high sulfur Eastern coal fly ash has a good resistivity on its own. The addition of the typical injection quantity of 10% $Ca(OH)_2$ does increase resistivity, by up to ½ order of magnitude. This does not increase resistivity to a severe condition, but it is a small move in the poorer direction. At the same time the 10% increase in inlet dust loading is also a small move in a poorer direction. So there is some possibility of an increase in particulate emission. In this case, the ESP must be studied specifically to see if the increase in inlet dust loading would cause a "bogging down" of the inlet fields of the ESP. This will be dependent on ESP size, inlet field electrode geometry, and ESP rapping density. There is potential that injection could cause higher particulate emissions, if the ESP is marginal in size or design.

In addition to unreacted $Ca(OH)_2$, there will be products of the reaction mixed with the fly ash. Other species might be $CaSO_4$, $CaCL_2$, $CaCO_3$, and $Ca(SO_3)$. Resistivity tests on all these species are shown on Figure 3;

Figure 3

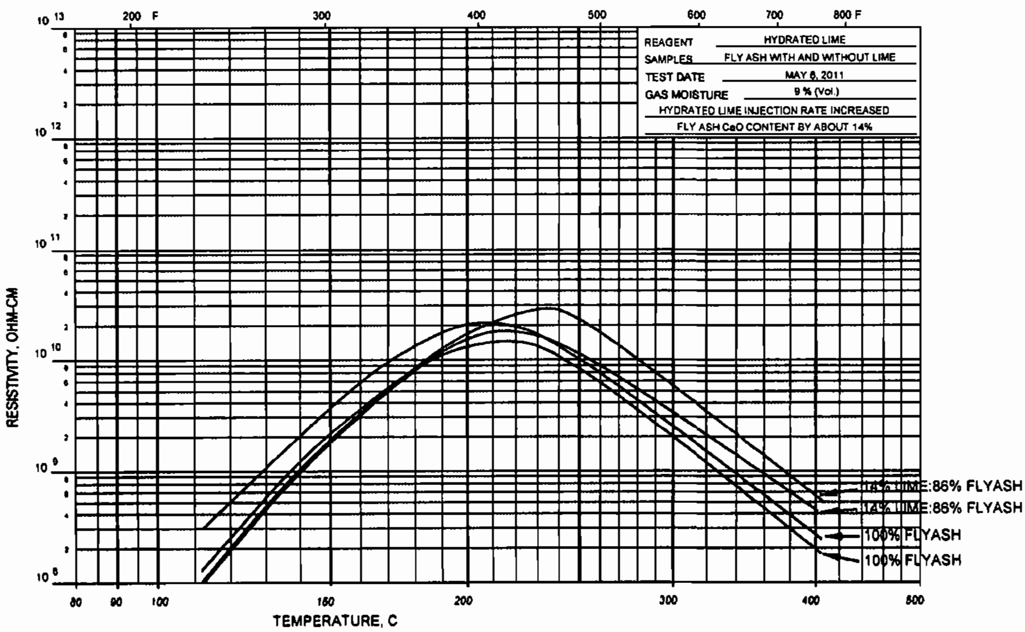


As can be seen from this data, calcium carbonate (limestone or $CaCO_3$) does indeed have a high resistivity. Calcium carbonate is probably the source of most of the concern in cement plants with ESPs. Cement plants are a well known difficult application for ESPs. However, this is with a particulate chemistry that has a high level of calcium species, while in contrast utility plants the injection rates will typically only result in low levels (i.e. 5-15%) of lime in the fly ash.

Of the reaction products, calcium sulfate had the highest resistivity. The calcium sulfite and calcium chloride actually have low/good resistivities in the temperature range of typical utility flue gas (i.e. 250-330 F). These species would actually serve to reduce resistivity if admixed with fly ash.

In the Figure 1 and Figure 2 studies, the hydrated lime was added in varying concentrations in the laboratory. However, resistivity studies were also conducted on actual flyash samples, with and without hydrated lime injection in the ductwork of a utility coal fired boiler. These results are shown in figure 4;

<u>Figure 4</u>



Within the experimental accuracy of the resistivity equipment, these results show almost no change in resistivity between;

100% fly ash (i.e. 20.1% CaO, 4.3% MgO, and 39.4% SiO_2)

86% flyash:14% injected CaO (i.e. 34.2% CaO, 3.3% MgO, 27.3% SiO_2)

At high temperatures, the flyash with injected lime was very slightly higher in resistivity. But at typical utility cold-side operating temperatures, approximately 300 F, the 100% fly ash was actually slightly higher in resistivity than the flyash with injected lime. The measurements were so close that they even crossed over each other, depending on temperature. Thus the low injection rates of hydrated lime were judged to have no significant effect on the fly ash resistivity for this application.

SUMMARY

Sufficient data now exists on the subject of resistivity impacts of hydrated lime injection to draw educated conclusions about the performance of electrostatic precipitators. In general, the utility boiler impacts were not as dire as once expected based upon cement plant experience. For low sulfur coals, low injection rates appear to have very little impact on fly ash resistivity. For high sulfur coal, low fly ash bulk resistivity and high levels of sulfuric acid surface conditioning result in good resistivities. In both cases, ESP performance can be predicted using ESP sizing models and resistivity predictions based upon laboratory measurements. In operation, resistivity can be modified by changing temperature and flue gas moisture content. So there are process options available if the products of sorbent injection do cause a detrimental impact on resistivity.

Acknowledgement to Michael Tate and Graymont Corporation for providing samples and chemical analyses for many of the samples tested for this paper

References;

1. Industrial Electrostatic Precipitation, H. J. White, Copywrite 1963.
2. Criteria and Guidelines for the Laboratory Measurement and Reporting of Fly Ash Resistivity, IEEE Std 548-1984.
3. The Art of Electrostatic Precipitation, Jacob Katz, 1980.
4. Applied Electrostatic Precipitation, K. R. Parker, 1997.

Attachment D

July 2, 2012

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Re: Comments on Gulf Power's Ten-Year Plan Submittal

Dear Mr. Ellis and Ms Matthews:

Thank you for accepting these comments on behalf of the Sierra Club and its more than 27,000 Florida members, and on behalf of Earthjustice. We look forward to participating in the Public Service Commission (PSC)'s Ten-Year Plan review process. We are writing to help inform the Commission of serious regulatory risks which should be addressed in this Ten-Year Plan.

As you know, Ten-Year Plans are designed to provide a broad overview of a utility's "power-generating needs and the general location of its proposed power plant sites;" accordingly, plans must be "suitable" for planning purposes. F.S. § 186.801; *see also* F.A.C. §§ 25-22.070 & 25-22.071. These plans are among the many tools used by the Commission as it fulfills its statutory responsibilities to maintain "sufficient, adequate, and efficient service" and "fair and reasonable rates" for all Floridians. *See, e.g.*, F.S. § 366.03.

To do so, the Commission will have to address the implications of substantial new environmental compliance obligations at several aging coal-fired units. A recent report for state utility commissioners, primarily authored by former Colorado PSC Chair Ron Binz, puts the problem succinctly, reminding regulators that "[t]he U.S. electric utility industry, which has remained largely stable and predictable during its first century of existence now faces tremendous challenges," including the prospect of substantial retirements of aging coal-fired power plants. *See* Ron Binz & CERES, *Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know* (2012) at 5.[1] These "retrofit or retire" decisions will lead to significant changes in the Florida coal fleet, and the PSC will be charged with managing these shifts. As Commissioner Binz writes:

> The question for regulators is whether to approve coal plant closures in the face of new and future EPA regulations, or to approve utility investments in costly pollution controls to keep the plants running. Regulators should treat this much like an IRP proceeding: utilities

[1] Attached as Ex. 1.

> should be required to present multiple scenarios differing in their disposition of the coal plants. The cost and risk of each scenario should be tested using sensitivities for fuel costs, environmental requirements, cost of capital, and so forth. In the end, regulators should enter a decision that addresses all of the relevant risks.

Id. at 9.

These comments highlight some of these important risks. The Commission should use the Ten-Year Plan informational docket to fully investigate them. We have submitted similar comments addressing plans filed by several different utilities; this filing focuses on coal-fired power plants operated by Gulf Power.

I. Gulf Power's Plants Face Substantial Environmental Compliance Costs

Gulf Power's Lansing Smith, Crist, and Scholz plants are aging facilities lacking major pollution controls. These plants are an increasingly bad deal for ratepayers: In addition to posing a serious threat to public health, they are not economic to operate. As utilities and PSCs around the country are increasingly recognizing, rising pollution control and fuel costs make coal power an unattractive proposition, especially as energy efficiency, demand-side resources, and renewable power become ever more available and as natural gas prices continue at record lows. Multi-million dollar life-extension projects for aging coal plants are not prudent in these circumstances. Accordingly, Gulf anticipates that it is likely to retire many of its plants in the near future. Gulf Power Ten Year Plan ("Gulf Plan") at 3.

Because Gulf's plans have important implications for the "need ... for electrical power" in its service territory, and for how that need is to be met, as well on "fuel diversity within the state," on the "environmental impact" of any proposed replacement power, and on the state "comprehensive plan," *see* F.S. § 186.801, the Commission should ensure that Gulf discloses its intentions in its Ten-Year Plan as fully as possible. It is particularly important to do so because Gulf will face compliance obligations within the next few years that will lead to retirement decisions. The Commission can best protect Floridians by beginning the planning process for these likely retirements now. The Plan is not suitably detailed to allow for this planning to be successful, so, at the end of these comments, we respectfully urge the PSC to require Gulf to submit critical additional information.

Gulf Power's Lansing Smith and Scholz plants are the most likely retirement targets because both plants lack "scrubbers," the flue-gas desulfurization systems required to remove SO_2, which can cause deadly respiratory damage, and other acid gases from their emissions. Scrubber systems for these plants would cost hundreds of millions of dollars. Such an investment, and the corresponding rate increase, would not be prudent when much cheaper sources of power are available. Accordingly, the Commission should work with Gulf Power to investigate retirement options for these plants.

In the discussion below, we explain the likely sources of scrubber liability for the Lansing Smith and Scholz plants, before briefly highlighting the many other environmental compliance costs which Gulf is likely to face.

A. Likely Scrubber Liability for Gulf Power Facilities

Three separate environmental and public health protection programs are likely to drive scrubber installation requirements, and hence "retire or retrofit" decisions, at the Lansing Smith and Scholz facilities: the SO_2 National Ambient Air Quality Standards ("NAAQS"), 40 C.F.R. § 50.17, the Mercury and Air Toxics Standards ("MATS"), 40 C.F.R. Subpt. UUUUU, and the Regional Haze Rule, 40 C.F.R. § 51.308.

i. The SO_2 NAAQS

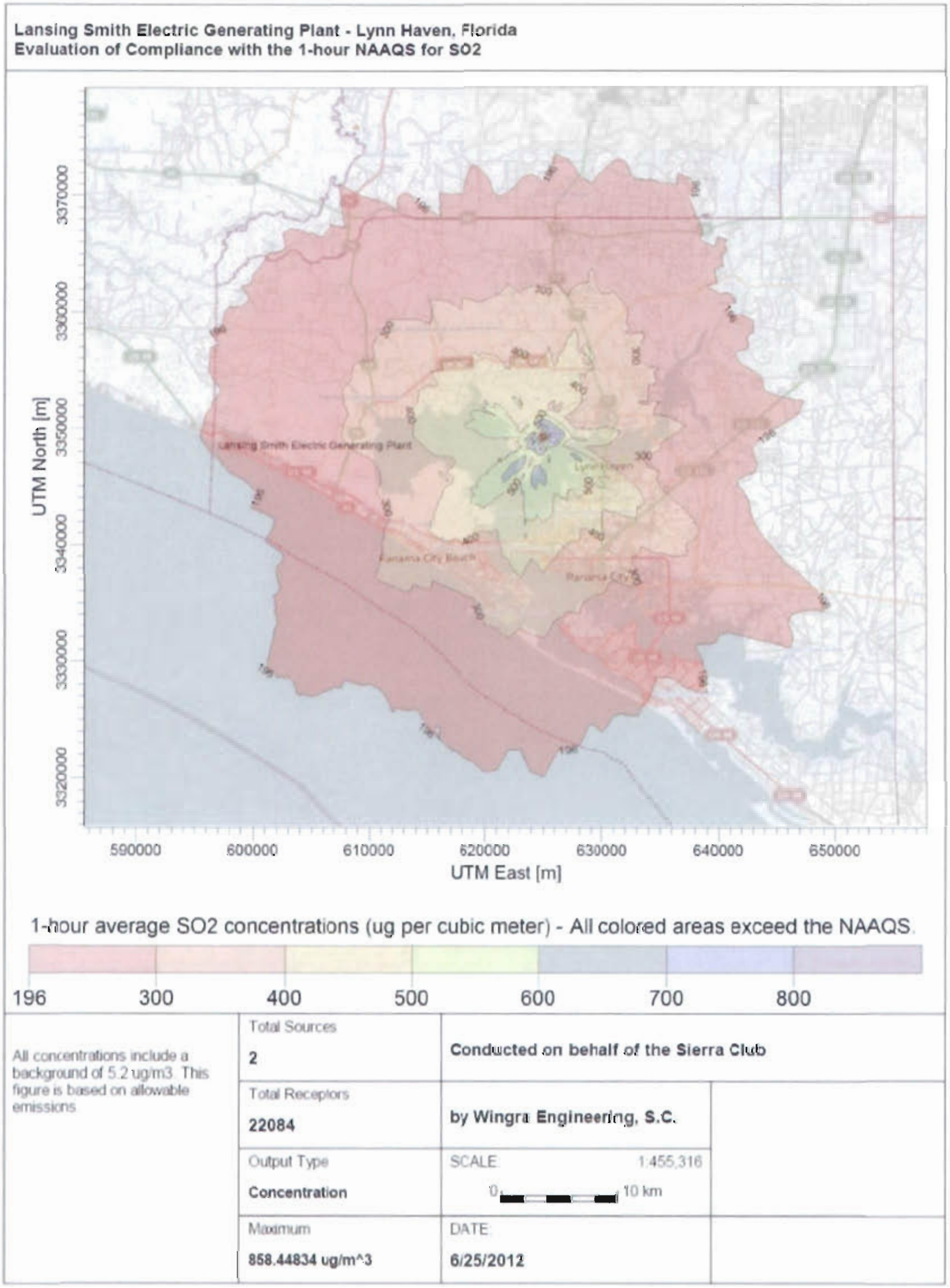
Just five minutes of exposure to SO_2 can make people sick; in fact, the causal link between this pollution and asthma attacks and other respiratory problems is the "strongest" such link which the EPA's scientific advisory board can identify. 75 Fed. Reg. 35,520, 35,525 (June 22, 2010). To protect the public from such pollutants, EPA is required to set NAAQS specifying the safe level of public exposure; states then develop state implementation plans (SIPs) to ensure that those standards are attained. *See* 42 U.S.C. §§ 7409 & 7410. EPA's decision to protect public health by lowering the NAAQS for SO_2 to a maximum allowable exposure of 75 ppb (a concentration equivalent to 196.2 $\mu g/m^3$) over an hour, *see* 75 Fed. Reg. 35,520 (June 22, 2010), thus obliges Florida to update its SIP to ensure that its citizens are protected from this dangerous air pollution.

States are generally required to submit updated SIPs "within 3 years" after EPA updates a NAAQS; because EPA finalized its NAAQS in 2010, Florida's plan is due in 2013. 42 U.S.C. § 7410(a)(1). The plan must "provide[] for implementation, maintenance, and enforcement of" the standard throughout Florida. *Id.* Although EPA's approval and review process may delay plan implementation for a year or two after submission, the Commission can reasonably expect Florida's SIP to be operating by 2015 or before.

This tight timeline is directly relevant to the Commission's review of Gulf Power's plans because the Lansing Smith plant is causing violations of the NAAQS, and so will have to install controls under any legal SIP. Sierra Club engaged an expert air modeler, Steve Klafka of Wingra Engineering, to evaluate the plant's compliance with the NAAQS, using EPA's models and methodology.[2] We modeled both the plant's allowable emissions – those authorized by its Title V Air Operation Permit, No. 0050014-018-AV – and its maximum emissions in 2011, the most recent year with complete data in EPA's Air Pollution Markets Database. Whether measured by its permit or by its most recent maximum emissions, the plant causes the pollution in the air over Panama City to reach unsafe levels, violating the NAAQS several-fold.

[2] The methodology is described in detail in the attached report, Ex. 2.

The figure below shows the SO_2 pollution plume the plant would create when operating at its permit limits. All colored areas violate the NAAQS. While the NAAQS is set at 196.2 $\mu g/m^3$, Lansing Smith's permit allows pollution levels to soar to 858.4 $\mu g/m^3$, over 400% of the safe value; even a bit further away from the plant, pollution directly over downtown Panama City reaches levels close to double the safe value.



Importantly, Lansing Smith causes NAAQS violations even when operating below its permitted maximums. Last year, Lansing Smith's highest operating hour emissions saw SO_2 concentrations reach 346.5 µg/m^3, which is nearly double the safe value. *See* Ex. 2 at Table 1.

Indeed, Lansing Smith's SO_2 emissions are so extreme that, according to the Florida Department of Environmental Protection ("FL DEP"), they even violate the far more lenient NAAQS that the new standard replaces. *See* FL DEP Permit No. 0050014-018-AV at 5. As such, FL DEP requires Gulf Power to post no trespassing signs to "protect the general public" from crossing the plant's fence line, within which the pollution is the most intense. *See id.* This is not a safe facility.

To reduce this illegal pollution, Lansing Smith would have to cut total facility emissions by 77.6% from its current permit. *Id.* at Table 3. To do so, it is highly likely to have to install a scrubber, thereby confronting hundreds of millions in control costs, which we document more fully below. Importantly, these costs will be far outweighed by public health benefits. EPA determined that the NAAQS will produce on the order of $36 billion in *net* benefits once safe levels of SO_2 have been attained. 75 Fed. Reg. at 35,588. Panama City residents will secure a substantial portion of these benefits – in the form of fewer asthma attacks, emergency room visits, and premature deaths – once Lansing Smith's pollution has been controlled.

We have not yet modeled the Scholz facility, but it is also an unscrubbed coal boiler, burning high-sulfur bituminous coal, and its permitted emissions are far higher than Lansing Smith's. While the Lansing Smith permit allows emissions of up to 4.50 lbs/MMBtu of SO_2, FL DEP Permit No. 0050014-018-AV at 8, the Scholz permit allows the facility to emit up to an astonishingly 6.17 lbs/MMBtu, FL DEP Permit No. 0630014-010-AV at 6. FL DEP candidly acknowledges that this emission rate "indicates exceedances" near the facility of even the more lenient NAAQS which EPA has since replaced, and so requires Gulf Power to take "precautions... to preclude public access." *Id.* Scholz is an even dirtier plant than Lansing Smith, and so is very likely to run afoul of the new NAAQS as well.

In short, the SO_2 NAAQS, a pollution control requirement which Gulf Power does not even acknowledge in its Ten-Year Plan, is highly likely to require the Lansing Smith and Scholz facilities to retrofit or retire. It is not the only requirement to do so, as we next discuss.

ii. MATS Requirements

In the Clean Air Act of 1990, Congress ordered EPA to investigate hazardous air pollutants emitted by power plants, and to promulgate emissions standards for these pollutants if they threatened public health. 42 U.S.C. § 7412(n)(1). Because coal power plants are dominant sources of mercury, acid gases, and other highly toxic pollutants, EPA was obligated to issue such standards, and finally did so in 2012, 22 years later. *See* 77 Fed. Reg. 9,304 (Feb. 16, 2012).

The final MATS rule issued in response to this Congressional mandate requires operators to control mercury and acid gases. A smoke stack scrubber can be required to comply with EPA's control requirements. In EPA's analysis of facility compliance options, it presumed that coal plants emitting more than 2 lbs/MMBtu of SO_2 would have to install scrubbers to comply with the standard. 77 Fed. Reg. at 9,412. As we note above, Lansing Smith emits more than twice this amount, and Scholz emits *three times* this threshold quantity. As such, scrubbers will very likely be required at these plants in order to comply with MATS.

The Clean Air Act requires that existing sources comply with MATS "as expeditiously as practicable, but in no event later than 3 years after the effective date" of the standard. 42 U.S.C. § 7412(i)(3). Because MATS was promulgated and effective on February 16, 2012, plants must comply by that date in 2015. Although limited compliance extension of up to 1-2 additional years may be available in some limited circumstances, *see id.*, these extensions are disfavored.

Accordingly, as Gulf Power recognizes, MATS "may severely restrict Gulf's coal-fired generation or completely eliminate the generation produced by Gulf's coal-fired units at Plants Smith and Scholz by as early as 2015." Gulf Plan at 3.

iii. Regional Haze Requirements

Since 1977, the Clean Air Act has required EPA and the states to make "reasonable progress" towards restoring natural visibility in Class I areas – which are essentially national parks and wildernesses. *See* 42 U.S.C. § 7491. EPA's rules to address regional haze, promulgated in 1999, are now being implemented. Florida is the process of a SIP revision intended to protect Class I areas affected by sources in the state. *See* FL DEP, *Regional Haze Plan for Florida Class I Areas* (Draft as amended May 2012).[3] Gulf Power has already determined that this rule, alone, may lead it to retire the Lansing Smith facility.

The regional haze rule requires that Florida impose controls at all sources of visibility-impairing pollutants to the extent such controls will be needed to make reasonable progress towards restoring natural visibility by 2064. *See* 40 C.F.R. § 51.308(d)(3). The Act and the Rule also require sources which were in existence by August 7, 1977, but which had not been in operation before August 7, 1962, to install "the best available retrofit technology" (BART) to control visibility-impairing pollutants. 42 U.S.C. § 7491(b)(2)(A) & 40 C.F.R. § 51.308(e). FL DEP has determined that the Crist facility is subject to reasonable progress analysis and that Lansing Smith is subject to BART. *See* FL Draft Regional Haze Plan at 98 & 102.

FL DEP had planned to rely upon a separate EPA SO_2 trading program, the Clean Air Interstate Rule ("CAIR") to address these requirements, but CAIR has been replaced with a new program which does not control SO_2 in Florida. *See* 77 Fed. Reg. 31,240, 31,248 (May 25, 2012). As such, FL DEP is reanalyzing control options and will have to consider source-specific control

[3] Available at http://www.dep.state.fl.us/air/rules/regulatory/regional_haze_imp.htm.

requirements for Crist and Lansing Smith. Scholz should also be implicated in this re-analysis because FL DEP had previously excluded relatively small facilities largely because it assumed CAIR would address most SO_2 emissions. Now that CAIR is no longer available, Scholz will have to be analyzed as well. Thus, as a result of these analyses, FL DEP will have to address SO_2 emissions, in some fashion, from all of Gulf Power's coal plants.

These controls are likely to drive scrubber requirements (and other controls or operating restrictions at scrubbed plants like Crist) because, according to FL DEP, SO_2 is the dominant source of visibility-impairing pollution in Florida. *See, e.g.*, FL Draft Regional Haze Plan at 91-92. Thus, these rules, too, are highly likely to drive scrubber requirements at the Lansing Smith facility.

Gulf Power has admitted as much to FL DEP. In a "BART Implementation Plan" submitted to DEP on May 21, 2012[4], it indicated that it will complete a BART analysis for Lansing Smith, and that it will decide, by January 1, 2015, whether to install a scrubber on the plant by 2018 (or later), "commit to retire the operation of Smith Unit 1 by January 1, 2022 and Smith Unit 2 before January 1, 2021," or to seek permit levels by 2015 reducing plant operations below BART emissions limits. Gulf BART Plan at 2. Because BART determinations will be approved within the next year, it is not at all clear how Gulf Power expects to run its plants until the early 2020s. Retirement within the next few years is the more likely option.

iv. Scrubber Costs

We have calculated the approximate cost of installing and running scrubbers (at 90% efficiency, a level which would likely be required, at a minimum, to meet the requirements of all three relevant rules) at Lansing Smith and Scholz, based upon the EPA's Integrated Planning Model and a scrubber-focused appendix developed by Sargent & Lundy.[5] This model predicts that the capital costs for fitting Lansing Smith Units 1 and 2 with scrubbers at $234 million. The incremental costs (including running costs) of these upgrades would be $43.1/MWh annually. Gulf Power would no doubt seek to pass these costs on to rate-payers if it opted to continue to run the plant, rather than to retire it.

Scrubber costs for Scholz are also very high. Using the same government modeling, we calculated that scrubbers for Scholz units 1 & 2 would cost $106 million to install, yielding a $243.5/MWh spike in incremental costs.

These figures do not include the incremental costs of effluent controls for scrubber waste. Any such additional upgrades would, of course, add to these costs, as would any additional measures required at Crist to bring that facility into compliance. The expenditures are extraordinarily high simply in order to extend the lives of these decades-old, expensive, coal-fired power plants. Gulf Power is unlikely to make them and, we submit, it would not be

[4] Attached as Ex. 3.

[5] All modeling parameters can be found at http://www.epa.gov/airmarkt/progsregs/epa-ipm/BaseCasev410.html.

appropriate for the Commission to authorize such costs where less expensive options are available.

B. Other Environmental Liabilities

As Gulf Power acknowledges, Gulf Plan at 3, scrubber costs are not the only liabilities it faces. There are also pending rules requiring upgrades to coal plant cooling water systems, *see* 76 Fed. Reg. 22,174 (Apr. 20, 2011), better handling and disposal practices for coal combustion waste, *see* 75 Fed. Reg. 35,128 (June 21, 2010), and new treatment systems for liquid effluent discharges,[6] all of which are likely to be finalized in the next two years. EPA is also updating the NAAQS for particulate matter and for ozone. Moreover, EPA has recently proposed carbon controls for new electricity generating units. *See* 77 Fed. Reg. 22,39 (Apr. 13, 2012). Once finalized, these rules will obligate EPA to extend carbon controls to existing facilities, including Gulf Power's fleet. *See* 42 U.S.C. § 7411(d). The cumulative impact of these liabilities on Gulf Power will be large. Indeed, according to Gulf, "the additional costs to comply with the final versions of EPA's proposed water quality and coal combustion by-product rules" alone "may result in total combined compliance costs that render controlled coal-fired operations uneconomical in the long term." Gulf Plan at 3.

Coal ash costs will be particularly pressing for Gulf Power. According to the Toxic Release Inventory, its Lansing Smith facility discharged 520,281 pounds of ash to its impoundment in 2006, a typical year, making Lansing Smith the 57th largest source of ash in the country and the second largest sources in Florida.[7] Highly troublingly, carcinogenic hexavalent chromium, which leaches from coal ash, has been found in groundwater wells near Lansing Smith at over 5,000 times safe levels (as determined by California for its drinking water goals), and above federal standards.[8] Clean-up costs for this contamination, including halting wet storage of ash, will be yet another substantial expense for the plants.

C. Likely Retirements

The cumulative compliance costs from all the rules which apply to Gulf Power's fleet are very large. Upon reviewing them, and considering the wide availability of more inexpensive power sources, Gulf Power is highly likely to follow industry trends towards coal retirement.

Coal use is falling quickly, in response both to the cost of pollution controls and to national economic trends, including the growth of inexpensive wind power and the boom in shale gas production. As EPA has recently documented, "all indications suggest that very few new coal-fired power plants will be constructed in the foreseeable future." 77 Fed. Reg. at 22,413, and the Energy Information Administration (EIA) is documenting increasing retirements of existing plants. In particular, the EIA's Annual Energy Outlook for 2012 forecasts no new unplanned

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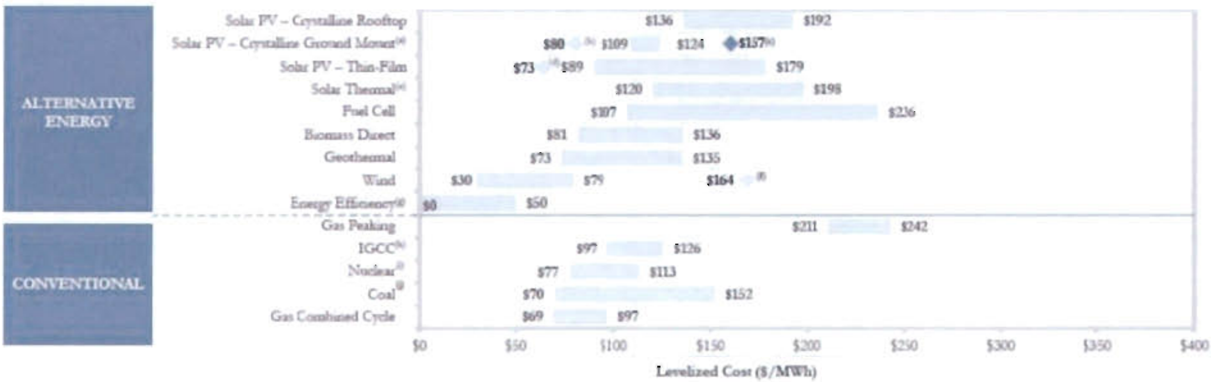
[6] *See* EPA's plans for this rule at http://water.epa.gov/scitech/wastetech/guide/steam_index.cfm
[7] *See* Ex. 4, attached.
[8] Lisa Evans, *EPA's Blind Spot: Hexavalent Chromium in Coal Ash* (2011) at 6, attached as Ex. 5.

coal capacity through 2020. RIA at 5-5. EIA's most recent Electric Power Monthly report confirms that this trend continues. Thus far this year, *none* of the 5,627 MW of new units to come online are coal-fired; instead, new capacity additions are largely in renewable power or natural gas. EIA, *Electric Power Monthly June 2012* at Table ES3.[9] Conversely, retirements to date have been predominantly coal-fired units. *See id.* at Table ES4. Utilities across the country have announced thousands of megawatts worth of coal retirements over the last few years.[10]

Industry-wide levelized cost figures compiled by independent analysts demonstrate why these retirements are occurring. The most recent (2011) edition of Lazard's Levelized Cost of Energy Analysis,[11] a widely-used reference, shows that energy efficiency, wind, and natural gas combined cycle levelized costs are already below those of coal, as the figure below demonstrates.



Under these circumstances, prudent operators are increasingly deciding not to impose additional costs on their ratepayers by running coal-fired units with costly new pollution technology. Instead, they are opting to retire older units and pursue cleaner, cheaper, energy options. Gulf Power could, and should, decide to follow the same course.

D. Recommended Commission Action

Although Gulf Power has acknowledged that some retirements may occur, it nonetheless "assume[s]" that Lansing Smith and Scholz "will be available to operate on coal throughout the 2012-2021 planning cycle." Gulf Plan at 3. As we have demonstrated above, this assumption is

[9] Available at: http://205.254.135.7/electricity/monthly/pdf/epm.pdf.
[10] *See, e.g.*, Progress Energy Press Release, "Progress Energy Carolinas to retire coal power plant ahead of schedule" (Apr. 1, 2011) (recording the retirement of four North Carolina coal plants), available at https://www.progress-energy.com/company/media-room/news-archive/press-release.page?title=Progress+Energy+Carolinas+to+retire+coal+power+plant+ahead+of+schedule&pubdate=04-01-2011; FirstEnergy Press Release, "FirstEnergy, Citing Impact of Environmental Regulations, Will Retire Six Coal-Fired Power Plants" (Jan. 29, 2012) (announcing the retirement of six coal plants in Ohio), available at https://www.firstenergycorp.com/content/fecorp/newsroom/news_releases/firstenergy_citingimpactofenvironmentalregulationswillretiresixc.html; Environment News Service, "Dominion Virginia to Replace Coal Plants with Gas, Nuclear" (Sept. 7, 2011) (documenting retirement of two Virginia coal plants), available at http://www.ens-newswire.com/ens/sep2011/2011-09-07-091.html.
[11] Attached as Ex. 6.

arbitrary and unsupportable: The compliance periods for the scrubber-forcing rules will run within the next two years and retirements will very likely occur within that period, and certainly will occur within the next decade. This error, and Gulf Power's failure fully to address the impacts of retirements upon its system and upon ratepayers, renders the draft plan "unsuitable" as a planning document. *See* F.S. §186.801. The Commission, "may suggest alternatives to the plan," *id.*, however, and may classify a plan as suitable upon the submission of "additional data," *see* F.A.C. § 25-22.071(5). We respectfully request that the PSC exercise its authority to ensure that Gulf Power's plan provides adequate data to allow the PSC and the public to address these plant retirements.

Specifically, we submit that the Commission should seek the following information from Gulf Power and require resubmission of a complete plan addressing these submissions:

1. The utility should provide an analysis of all environmental compliance obligations which it will experience at all of its coal-fired facilities. For each requirement, the utility should cite the relevant rule, explain how it is likely to apply to the plant, the likely costs of compliance to the utility and to ratepayers, and the timeline on which compliance will be required. The utility should also document any steps it has taken to address these compliance obligations, and alternative steps it might take. For instance, if the utility anticipates that it will have to install a scrubber to comply with MATS, it should report to the Commission on scrubber installation and operation costs, whether it has contracted to purchase a scrubber and on what timeline, and what other options it has considered. *See* F.S. § 186.801 (requiring utilities to document "[p]ossible alternatives to the proposed plan").

2. The utility should provide a comparative analysis of compliance costs and the cost costs of replacing the plant's power through energy efficiency, demand response, power purchase agreements, new generation facilities, or other means. *See* F.S. §186.801 (requiring utilities to explain the impact of their plans on fuel diversity and on the need for electric power in their regions). In light of this analysis, the utility should indicate whether it intends to retire any facility, and on what timeline, and the relative costs of retirement versus those of other options. If retirement has not been selected but is being considered, the utility should indicate when the decision will be made.

3. For any facility where retirement is possible, the utility should discuss how it intends to address any reliability issues which may be caused by the retirement. The Commission should play an active role in this regard, as it must maintain reliability of the electric grid. *See* F.S. § 366.05(7)-(8) (authorizing the Commission to "require reports from all electric utilities to assure the development of adequate and reliable energy grids" and to order "installation and repair of necessary facilities" to address reliability issues"). The Commission has determined that "[r]eserve margins in Florida typically remain well above" relevant minimums through 2020, so system-wide resource adequacy problems are unlikely, but the Commission may still need to

address localized reliability issues. If such problems appear to be present, the Commission should work proactively and transparently with the Florida Reliability Coordinating Council to address them well in advance of any planned retirement.

We appreciate this careful consideration of Gulf Power's environmental compliance options, and any resulting plant retirements, and remind the Commission that such thorough analysis is required to ensure that the Ten-Year Plan complies with legal requirements. We request that the Commission share the results of its inquiry with us and with the public, and request formal notice of the Commission's next steps.

Please contact the undersigned with any concerns or questions.

Sincerely,

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