TEST RESULTS OF MULTI-POLLUTANT EMISSIONS REDUCTION SYSTEMS

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ABSTRACT

The EPA’s Mercury and Air Toxics Standards (MATS) rules released at the end of 2011 requires power plants to reduce emissions of heavy metals and acid gases. MATS is one of the first new emissions regulations that will add cost and uncertainty to fossil fuel power generation. As a result, utilities face the choice of retiring assets early, switching to different fuel sources, or installing traditional emissions reduction technologies. This paper discusses a different, more economical multi-pollutant control technology option, developed and patented by Eco Power Solutions (EPS). This technology will help power generators meet these fast approaching EPA deadlines while offering the flexibility to meet future, more stringent, requirements cost effectively without the need for an extended plant outage. This argument is supported by presenting performance data from state-of-the-art, multi-pollutant emission control systems in Louisville, Kentucky that have been operating since June 2010. The data collected for critical pollutants -- NOx, SO2, CO2, HCl, etc. – are presented in tables and graphs with their percentage removal rates to show the effectiveness of the system in removing these emissions simultaneously. In addition, test results showing the Hg reduction capabilities of the system are discussed. This patented system utilizes two reagents as an integral part of the process; ozone and hydrogen peroxide are introduced to facilitate removal of NOx and SO2. The impact of these reagents on the process as well as the overall emission profile of the plant is also discussed.

INTRODUCTION

Emission control technologies have been helping the power generation industry reduce its pollution output since the Clean Air Act of 1990. The myriad of methods and technologies applied to date have significantly reduced plant emissions, with significant decreases in NOx, SOx and particulate matter emissions. However, MATS puts power plants on a strict three-year timeline to reduce emissions of heavy metals (including mercury, arsenic, chromium, and nickel) and acid gases; and EPA updates to the Maximum Achievable Control Technology (MACT) rules require power plants to periodically revisit their control strategies. In addition, the EPA has proposed new greenhouse gas emission regulations for new coal fired power plants. This regulation would require generators to reduce their CO2 emissions to less than 1000 lbs. of CO2/MWh.

Throughout the power generation industry, companies are weighing the costs and benefits of several different solutions for meeting the emission reduction standards. This will be a daunting task because emissions control on this scale has never been done before. Due diligence requires close examination of new and existing emissions control technologies to ensure that they comply with regulations while meeting power generation needs. Traditional technologies have historically required a separate and distinct system for each controlled pollutant. This has led many generators to install numerous systems that have come at a high cost and with significant disruptions of plant availability.

Multi-pollutant control systems are a more recent option to enter the market and hold promise to overcome several of the drawbacks of traditional emissions control systems. This option, now being offered by several companies, uses a single system that removes multiple targeted pollutants from flue gas before they are released into the atmosphere. Through extensive testing, this form of emissions control system has shown that it can capture Hg, PM, CO2, NOx, SOx, acid gases and heavy metals.
Multi-pollutant control systems offer extensive benefits to electric utilities searching for an option to meet rapidly approaching deadlines at a less disruptive cost. These systems regularly require a lower capital investment than a series of its traditional technologies that would be needed to eliminate the same number of pollutants. This all-in-one approach allows utilities to meet current regulations while serving as a hedge against future regulations. It also allows systems to be installed more quickly and with a smaller footprint. Additionally, some of these systems use a modular design that ensures scalability for larger boilers and offers the potential for removal of CO₂, providing a second hedge against a potential cap-and-trade scheme or carbon tax.

This paper discusses Eco Power Solutions’ (EPS) multi-pollutant emission control technology that has been successfully operating for more than two years. The technology has proven it can consistently reduce mercury emissions by more than 95 percent, with the ability to address mercury re-emissions. Additionally, it has demonstrated the ability to reduce NOx and SOx emissions by more than 98 percent, as well as arsenic, chromium and nickel by more than 95 percent, and CO₂ by 30 to 50 percent.

Finally, this technology does not require modifications to the boiler, air heater or particulate collector contrary to systems such as SCRs. In addition, the EPS technology does not require injection of compounds in powdered form which can increase the ash load on the particulate system and potentially alter the make-up of the ash. It is a low-temperature, back-end system that can be readily retrofitted to an existing plant. It is a relatively simple system, from an operation and maintenance aspect, and offers the flexibility of generating revenues from the sale of byproducts.

EMISSION REDUCTION PROCESS

For this paper, primary pollutants are defined as NOx, SOx, HCl, HF, heavy metals including mercury and particulate. The basic premise of the EPS system is to convert the pollutants into water soluble components and then condense those compounds out as a mixed wastewater effluent stream. As is well understood, NOx mainly consists of NO and NO₂. For fossil fired plants, typically NOx consists of 95% NO and 5% NO₂. NO₂ is water soluble and NO is not, at least not practically. As a first step in this technology’s process, NO is converted to NO₂ by injecting ozone in the flue gas stream. The reaction is straight forward:

\[ \text{NO} + \text{O}_3 \rightarrow \text{NO}_2 + \text{O}_2 + \text{light} \]  

This Ozone injection occurs upstream of the unit in the ductwork, and it is the only process to take place outside the unit (Fig. 1). The injection point is selected to allow sufficient residence time for the reaction to take place so all NO has been converted to NO₂ by the time flue gases reach the unit.

High pressure water is introduced early in the process with the purpose of quenching the gas to a temperature below the dew point of the newly formed water soluble compounds thus condensing out the pollutants into the wastewater effluent stream.

SOx in the form of SO₂ and SO₃ is also addressed. The sulfur compounds are removed with the addition of diluted peroxide injection through the first fogging stage causing the following reactions:

\[ \text{SO}_2 + \text{H}_2\text{O} \rightarrow \text{H}_2\text{SO}_3 \]
\[ \text{H}_2\text{SO}_3 + \text{H}_2\text{O}_2 \rightarrow \text{H}_2\text{SO}_4 \]
\[ \text{SO}_3 + \text{H}_2\text{O} \rightarrow \text{H}_2\text{SO}_4 \]  

With this process, the SO₂ to SO₃ conversion is not a factor as there is no catalytic reaction used in the EPS process.

The injection of water in the first fogging stage converts water soluble NO₂ to nitric acid as shown below:

\[ 4\text{NO}_2 + \text{O}_2 + 2\text{H}_2\text{O} \rightarrow 4\text{HNO}_3 \]  

The function of the second stage foggers is to provide additional water to complete any unfinished reactions and to help with the condensation process. Only water is injected through the second stage. The system is
designed in such a way that the amount of water sprayed and its distribution pattern provides adiabatic cooling of flue gases while initiating the condensation process for various acids. This condensation process is completed in the packing and mist eliminator sections. Downstream of the mist eliminator is a specially designed activated carbon adsorber that acts as a polishing agent to remove the last traces of targeted emissions.

The majority of halogens -- chlorine, fluorine and bromine -- have high affinity for water. As such they are readily converted to HCl, HF and HBr. These acids then condense out of the flue gas through the condensation process.

**MERCURY CONTROL**

Mercury present in the fuel, especially coal, is released during the combustion process as elemental mercury (Hg⁰), oxides of mercury (Hg₂) and particulate bound mercury (Hgₚ). The presence of chlorine vapor in the flue gases helps oxidation of mercury, which is water soluble and easily removed during the condensation process. The injection of ozone and hydrogen peroxide also helps the oxidation process. However, this reaction, which requires a certain temperature window for completion, does not convert all the elemental mercury. The activated carbon adsorber at the backend of the unit captures the majority of any remaining mercury thereby eliminating the problem of mercury re-emission at the stack.

The particulate bound mercury is removed by a baghouse or an ESP upstream of the unit.

**CO₂ CAPTURE CAPABILITY**

As an inherent part of the process, CO₂ is captured in the wastewater stream in two forms. The first is carbonic acid through the reaction below and the second is CO₂ dissolved in water. The effectiveness of CO₂ capture depends upon flue gas velocity, flue gas temperature and water injection flow and temperature.

\[
\text{CO}_2 + \text{H}_2\text{O} \rightarrow \text{H}_2\text{CO}_3
\]  

The selection of material within the unit and the design of various components to withstand the corrosive atmosphere as well as allow the emission reduction process to take place are proprietary information gained through years of research and development and running the units at several operating scenarios.

Even though the process of condensation can remove particulate, it is necessary to employ a particulate control device upstream of the unit to remove any heavy particulate loading which may plug the mist eliminators and/or drains.

**WASTEWATER TREATMENT**

The byproduct of this technology is a wastewater stream that contains various acids (nitric, sulfuric, hydrochloric, hydrofluoric, hydrobromic, phosphoric, carbonic, etc.), heavy metals (mercury, lead, cadmium, chromium, arsenic, nickel, silver, etc.) as well as any remaining particulate matter. This wastewater has low pH that needs to be neutralized by a variety of existing technologies. Typically limestone is the most cost effective solution, however, high density lime or caustic can be considered as well. Neutralization produces salts – sulfates, chlorides, nitrates, fluorides, etc. An important difference with conventional FGD system is that sulfates are produced in the EPS process instead of sulfites making the wastewater treatment system byproducts easier to handle. Other treatment options ranges from zero liquid discharge and gypsum production to the discharge of water with low salt content depending upon local discharge requirements. Arrangements can also be made with acid producers to take the discharge for acid production since the pH values are typically less than 2.0.

For natural gas-fired units, the wastewater consists primarily of low concentrations of nitric acid that can be neutralized and discharged. The typical expected range of pH is between 3.3 and 4.0.

The main challenge in dealing with the CO₂ concentrations is the wastewater is the development of an effective process to prevent the captured CO₂ from re-remitting into the atmosphere during the wastewater treatment process. EPS has been awarded a patent for the conversion of CO₂ to a marketable primary alcohol. Bench-scale testing is currently being conducted.

**SITE DESCRIPTION**

Eco Power Solutions’ Technology Center is located in Louisville, KY. It was designed and built to test as well as demonstrate the performance of its patented, multi-pollutant, emissions control technology. The site has one natural gas burner with a capacity of 24
MMBtu/hr of heat input and two coal burners, each capable of burning 70 lb/hr of coal.

Because their internal configurations are different, the gas and the coal burners have separate units (see Fig. 2). The gas unit has two stages of fogging arrays followed by a stationary activated carbon adsorber that acts as a polishing agent in removing any remaining traces of emissions. The coal unit has two stages of fogggers followed by a packing section, mist eliminator and carbon adsorber.

A single ID fan in the common exhaust duct handles both units.

In a retrofit application a booster fan will likely be required to account for the additional draft loss through the system. This booster fan can be placed either upstream or downstream of the unit. Placement downstream of the unit will require the fan to be specially coated to protect against any residual mist carryover. Placing the fan upstream of the unit eliminates any concerns over corrosion, but this will result in a higher auxiliary load. In the end, fan placement will depend upon site-specific conditions, user preference and economic evaluation.

At the Louisville facility reverse osmosis (RO) water is used for the condensate as well as for the foggers. City water with additional filtration can be used for the fogging spray as long as the conductivity is within the recommended range.

At the Louisville facility, wastewater is discharged after neutralization with caustic (see Figure 3). Use of caustic was justified in this case because the quantity of wastewater was relatively small and there were space limitations and ease of operation to consider.

The local discharge permit requires pH and temperature control. The local MSD does routine periodic checks by taking samples of the discharged stream and having it analyzed by a third-party independent laboratory.

ANALYZERS

The inlet and outlet emissions, NOx, SO2 and CO2, are monitored by CEMS equipment supplied by Teledyne. NO and NO2 are measured by chemiluminescent based analyzers. Ozone is measured only at the outlet to monitor the slip. The inlet measurement location is upstream of ozone injection to take readings of untreated flue gases. The sampling port for the outlet emissions is in the common ductwork downstream of the unit. A local historian allows retrieval of all data by these analyzers. These analyzers are calibrated prior to each test or client demonstration to maintain the authenticity and integrity of results.
In addition, there is a Gasmet supplied Fourier Transform Infrared Spectroscopy (FTIR) analyzer located downstream to measure HCl, SO₃, CO, acid gases, formaldehyde, etc. The FTIR also measures NOₓ, SO₂, CO₂ and is used to verify data by CEMS analyzers. The portable analyzer can also be used to take upstream readings for verification purposes, if required.

The opacity is measured by a Teledyne LightHawk Model 560 opacity/dust monitor. The meter is installed indoors in the outlet duct prior to duct penetration through the wall to the stack (see Fig. 4).

The test was run for one hour with readings taken every second and then averaged. Fig. 5 shows the plot of NOₓ removal rates. The average NOₓ reduction during the one-hour test was 95.1%. Note that with an outlet value of 0.35 ppm, the readings are within the range of the instrument accuracy. Higher reductions are expected with a higher inlet NOₓ value, as demonstrated for the coal unit. Fig. 6 shows the plot of CO₂ removal rates. The average CO₂ reduction was 11.1%. Again, the CO₂ removal rates can be improved by increasing water spray rate and the addition of packing, similar to the coal unit.

Table 1: Average operating conditions for gas unit during the one hour test run.

<table>
<thead>
<tr>
<th>Operating Conditions (3/28/2012)</th>
<th>Inlet</th>
<th>Outlet</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas Temp</td>
<td>400°F (204°C)</td>
<td>90°F (32°C)</td>
</tr>
<tr>
<td>NOₓ</td>
<td>6.95 ppm</td>
<td>0.35 ppm</td>
</tr>
<tr>
<td>CO₂</td>
<td>10,035 ppm</td>
<td>8,915 ppm</td>
</tr>
</tbody>
</table>
COAL UNIT TEST RESULTS

The ultimate analysis of the stoker coal used is shown in Table 2. The coal is bituminous from Gauley mine in Pennsylvania. The full capabilities of the system were tested, therefore hydrogen peroxide was injected in the first fogging stage in addition to ozone injection in the inlet duct to the unit. The packing material provides excellent protection against corrosive acids and contact surface between water and gases. The material used holds up well against corrosion and may never need replacement unless it is subjected to high temperatures due to an upset condition. However, there are features provided in the system to prevent this from occurring.

The data was taken during the Coal-Gen tour of the facility on Aug. 14. The average operating conditions during the test are shown in Table 3. Figures 8 through 10 show inlet and outlet concentrations of NOx, SO2 and CO2 as well as their respective percent reductions. The high reductions demonstrate that the system is well suited to meet more stringent emissions control requirements in the future.

Table 3: Operating conditions for the coal unit during the test run.

<table>
<thead>
<tr>
<th>Operating Conditions (8/14/2012)</th>
<th>Inlet</th>
<th>Outlet</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas Temp</td>
<td>257°F (125°C)</td>
<td>89°F (32°C)</td>
</tr>
<tr>
<td>NOx</td>
<td>43.36 ppm</td>
<td>0.44 ppm</td>
</tr>
<tr>
<td>SO2</td>
<td>216.58 ppm</td>
<td>0.00 ppm</td>
</tr>
<tr>
<td>CO2</td>
<td>13,865 ppm</td>
<td>3,352 ppm</td>
</tr>
</tbody>
</table>

The emission removal rates can be improved by introducing more ozone and hydrogen peroxide in the flue gas stream. The neutralizing reagent consumption remain the same. The only exception is in the capture of CO2, which requires higher water injection rates for greater efficiencies.

For this reason, it is important to note that the high CO2 capture rates were possible by increasing spray water. Adding more water beyond a certain rate does not improve other emission such as NOx, SOx and mercury, however. The CO2 dissolved in water eventually comes out over a period of time. As

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Eastern Bituminous Ultimate Analysis

<table>
<thead>
<tr>
<th></th>
<th>Carbon</th>
<th>Hydrogen</th>
<th>Oxygen</th>
<th>Nitrogen</th>
<th>Sulfur</th>
<th>Ash</th>
<th>Heating Value</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>69.9%</td>
<td>4.7%</td>
<td>6.4%</td>
<td>1.2%</td>
<td>2.2%</td>
<td>13.2%</td>
<td>12,644 Btu/lb</td>
</tr>
</tbody>
</table>

Table 2: Ultimate analysis of coal used at the facility.

Figure 8: NOx removal plot for coal testing.
In addition to NOx, SO2 and CO2 readings measured by CEMS equipment and as reported herein, there is an FTIR installed to measure several other emissions like SO3, HCl, HF, formaldehyde, etc. Since there is only one FTIR, it was placed downstream to measure

Figure 9: SO2 removal plot for coal testing.

Figure 10: CO2 removal plot for the coal testing.
outlet emission after treatment. The results are shown in the Table 4.

With only FTIR, the percent removal rates of some of these parameters cannot be precisely determined. However, one can conclude from the outlet emission levels that some of the criteria pollutants especially HCl, SO₃, HF, etc. are adequately addressed given the non-existent levels in the outlet flue gas stream.

The coal burners used to simulate the flue gases cannot be precisely controlled, resulting in an inefficient combustion process. In addition, there is no filtration upstream the system in our Louisville test center to reduce the flyash and soot carryover. Even with these limitations, the average opacity during the test run was 4.1%. No visible plume existed (see Fig. 11). As stated earlier, it is necessary to have either a well-functioning particulate collection device upstream of the system to prevent excessive flyash carryover.

<table>
<thead>
<tr>
<th>Outlet Emissions in ppm, FTIR</th>
</tr>
</thead>
<tbody>
<tr>
<td>HCl</td>
</tr>
<tr>
<td>SO₃</td>
</tr>
<tr>
<td>Formaldehyde</td>
</tr>
<tr>
<td>Methane</td>
</tr>
<tr>
<td>Propane</td>
</tr>
<tr>
<td>Hexane</td>
</tr>
</tbody>
</table>

Table 4: FTIR data at system outlet

Mercury Test

The mercury test was conducted on June 5 for the coal unit by placing sorbent traps in the inlet and outlet ductwork. Each trap has two sections of carbon filter. The test was run for 4 hours and a constant flow of 0.4 l/min was maintained through the traps for the duration of the test. After the test, the traps were sent to an independent lab to measure mercury deposited in both the sections of each trap. The mercury deposition for the inlet trap was reported to be 95.38 and 0.08 ng and that for the outlet trap was 9.87 and 0.77 ng. This amounts to a removal efficiency of 89%. Note that the measurements included elemental mercury also. Since this test was run the mist eliminators have been modified to reduce moisture carryover and efforts are underway to add a wire mesh filter upstream of the unit. Both of these modifications are expected to improve the mercury removal efficiencies to over 95%. The results of this test will be reported in the presentation.

CONCLUSIONS

The tests conducted on the natural gas and coal-fired units at Eco Power Solutions’ Louisville Technology Center, demonstrated the effectiveness of the units in controlling multiple pollutants simultaneously. The tests prove the patented, cold-end, one-in-all technology allows power generators to meet the current regulation air quality standards. The tests also provide the same power generator the assurance of future compliance without significant future capital investments in new systems.

ACKNOWLEDGEMENTS

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REFERENCES

