

CIBO INDUSTRIAL EMISSIONS CONTROL TECHNOLOGY VII CONFERENCE
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I. Compliance Workshop - Christi Wilson, Trinity Consultants, Inc.

An update was presented on recent regulations and rules including Industrial Boiler MACT, CISWI Solid Waste Definition, GHG legislation, CAIR, NSR, Proposed NO₂ NAAQS, and SSM. The rules for Industrial Boiler MACT comes under 40CFR Part 63, subpart DDDDD. A revised rule is now due on Sept. 15, 2009. Test data from the Section 114 requests are due Oct. 15, 2009, which leads one to question how the rule will take the data into account. The final rule is due July 15, 2010.

The definition of solid waste was challenged under the proposed rule, causing a vacatur of the rule. In January, EPA published an Advance Notice of Proposed Rulemaking for the definition of solid waste. Should a unit be found to be burning solid waste rather than fuel, the unit would be considered a waste incinerator and subject to more stringent rules. Under the MACT rules, the MACT floor is supposed to be set by taking the average of the best 12% of unit emissions for a given HAP or HAP surrogate. EPA requested data under Section 114, which is due Oct. 15th. Since a proposed rule is due on Sept. 15th, the MACT floor level will come under question. The testing is to be conducted at "typical maximum" load conditions with "typical" air pollution control device conditions.

For multi-fuel units, only the primary fuel needs to be tested. Sources have been requested to test for some combination of pollutants, including CO, NO_x, SO₂, THC, PM, PM_{2.5}, HCl, HF, Hg, dioxins/furans, methane, formaldehyde, and heavy metals. A written test protocol is not required, but is a good idea. For a few units, fuel sampling may be used in lieu of stack testing. Previously collected data may be used if it satisfies all of the requirements of the ICR. The scope of testing is extensive and the timeline is aggressive. Some small units may have difficulty in accomplishing these tests. There will be little or no time for repeat testing. Qualified source testing resources may be in limited supply. While some units only have a few compounds listed, most of the pulp and paper units have the complete list.

In the meantime, the debate on the "MACT Hammer" continues. This rule comes under Section 112 of the law. It was intended to force MACT controls on sources if EPA failed to promulgate MACT standards on a timely basis. It was not intended to apply to MACT standards that were finalized and then vacated. There was no CAA requirement designed to handle that specific circumstance. A few states have taken the position that the MACT Hammer has fallen and have instituted (case by case) MACT for new permits. Once a revised rule is published, "presumptive MACT" is supposed to apply. In this case, the proposed new rule would become the "de facto" MACT rule for permits under way. Of course, if the rule goes through several modifications as the data comes in, it is unclear which version of the rule would be "presumed". EPA has not released guidance for states to follow when developing standards for affected sources. There are many potential risks for affected sources including (unknown) standards and inconsistent application of standards, as well as the solid waste definition. There are wide differences amongst the vacated rule, the data collected by NACAA, the NACAA proposal, and some of the newly collected data. If a unit gets its Part 2 filing approved by a state under Section 112, that unit has some shield of approximately 8 years if a more stringent rule comes out after the approval.

In the GHG arena, EPA has issued a proposed Mandatory GHG Reporting Rule. This rule covers the monitoring, reporting, and record keeping requirements pertaining to combustion sources for GHGs. Proposed legislation has centered around the House bill known as Waxman /Markey, or ACES. There is also the proposed EPA Endangerment Finding. The GHGs included in the proposed rule include CO₂, CH₄, N₂O, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. The term "carbon dioxide equivalent" means the relative forcing of the gas in

question relative to CO₂. For example, methane (CH₄) is 21 times stronger than CO₂ in terms of greenhouse forcing. N₂O is 310 times stronger. That means that 1 ppm of N₂O causes as much greenhouse forcing as 310 ppm of CO₂. The sulfur hexafluoride is 23,900 times stronger. The rules are now being proposed in terms of CO₂ equivalent. Requirements are being given in metric tons. The lower limit for reporting is 25,000 metric tons of CO₂. This equivalent to a 53.5 MMBTU/hr natural gas combustor or 131 rail cars worth of coal.

There are four potential reporters for GHGs, including combustion sources, chemical producers, fuel suppliers and producers of industrial GHGs, and facilities not included in sources 1 and 2 that aggregate 30 MMBTU/hr or more and emit 25,000 tonne/yr of CO₂ equivalent. EPA has proposed a "once in, always in" approach. This would mean that a source that was required to report in 2010 would always have to report even if it subsequently reduced its GHG emissions below the 25,000 tonne/yr level. The subpart C source category includes devices that combust solid, liquid, or gaseous fuel generally for the purposes of producing electricity, generating steam, providing useful heat, or reducing the volume of waste. It includes (but is not limited to) boilers, combustion turbines, engines, incinerators, and process heaters. It does not include portable equipment or emergency generators.

The calculation includes a 4 tiered approach. The first tier is an emissions factor and a default heating value for the fuel. Tier 2 uses an emissions factor and the measured heating value of the fuel. Tier 3 uses a calculation based on the measured carbon content of the fuel. Tier 4 is a CEMS for CO₂. Tier 4 would apply to most units greater than 250 MMBTU/hr. CH₄ and N₂O will be based upon emissions factors. CO₂ from sorbents (limestone, trona, etc.) will be counted. Biogenic CO₂ will be reported but not used for applicability. Units with CEMS do not have to calculate the CO₂ from sorbents. Accuracy allowance values are being proposed at a minimum level of \$10/tonne in Waxman/Markey. Detailed records explaining how company records are used to estimate the various GHGs will be required. Methodology for sampling fuels and making measurements will need to be certified. Flow meters will need to be calibrated at least annually. Sampling frequency will be at least monthly and in some cases daily.

For Tier 4, all CO₂ and flow rate monitors will have to be certified prior to Jan. 1, 2010. Procedures specified in 40 CFR Part 75 will be applicable. Reporting will be done on an annual basis on March 31st for the prior calendar year. The annual report content will be facility name, address, and Federal Registry System identification number; year; date of submittal; annual emissions of GHGs; total electricity generated on site; total CO₂ captured; and a signed and dated certification statement. Self certification with EPA verification is proposed. Operators will be required to retain records for at least 5 years and must be made available to EPA upon request. Record keeping will include a list of all applicable facilities, all data used to calculate GHGs, results of all fuel analyses, documentation of all data collection processes, all emissions factors used, all facility operating data or process information used to calculate GHGs, names and documentation of key facility personnel involved in calculating and reporting GHGs, the annual GHG reports, a log book document any procedural changes, and any missing data calculations. A written quality assurance performance plan will be required.

There are already 2400 comments in the comment docket for this rule. Comment areas include electricity reporting, threshold limits, reporting deadlines, reporting frequency, regulatory authority, calculation methodologies, "once in - always in", double counting, and preemption issues associated with state and regional reporting requirements. A final rule is anticipated for November of this year with a reporting structure to be in place on Jan. 1, 2010.

The Waxman/Markey bill was passed in the US House of Representatives on June 26, 2009. While the main thrust is the cap and trade program, there is also a renewable energy standard and an energy efficiency standard. The Senate is expected to vote by the end of the year. The US president would like a bill signed before the Copenhagen COP meeting. Covered entities include any electricity source, any stationary source the produces petroleum or coal based fuels which would emit 25,000 tonne/yr CO₂, any source designated by the administrator that produces

25,000 tonne/yr CO₂ equivalent, and stationary source that has emitted 25,000 tons/yr, and any geologic sequestration site. The base period will be 2007-2010, with 2007 emissions to be reported by Mar. 31, 2011.

Starting in 2014, Industrial Stationary Sources would submit one allowance per ton of CO₂ emitted. Covered entities taking delivery from natural gas from distribution companies must notify them in writing each year by Sept. 1 (to avoid double counting). Utilities start in 2013. Electricity consumers will get 43.75% of the allowances in 2012, declining to 7% by 2029. Natural gas companies will get 9% beginning in 2016, declining to 1.8% in 2029. Heating oil and propane consumers will get 1.875%, declining to 0.3% in 2029. CCS bonus allowances will be issued at 2% during 2014 - 2017 and 5% from 2018 - 2050. International Forest Carbon will get 5% through 2025, 3% through 2030, and 2% through 2050. Energy efficiency will get 9.5% from 2012 - 2015, declining to 4.5% through 2050. Clean vehicle technology has 3% from 2012 - 2017, declining to 1% from 2018 - 2025. Domestic refiners get 2% from 2014 - 2026. International adaptation will get 1% from 2012- 2021, rising to 4% through 2050. International clean technology deployment will be similar. Output based rebates would get 15% through 2025, declining 10%/yr thereafter. These allowances have been modeled.

Additional allowances have been set aside for low income consumers (15%), trade vulnerable businesses (15% after 2014 and declining), clean energy innovation centers (1%), investment in workers (0.5 - 1%), domestic adaptation (0.9% and rising to 3.9% after 2021), climate health protection fund (0.1%), and wildlife and natural resource adaptation (1% and rising to 4% after 2027). Approximately 2.5 billion allowances are designated for a strategic reserve. International Emissions Allowances can "qualify" by meeting certain criteria. The program includes offsets, penalties, trading, and banking/borrowing. The EPA Endangerment Finding have been issued and is final. The Finding does not propose any specific regulation, but will lead to GHG vehicle/fuel standards and will impact stationary sources. Passage of Waxman/Markey will impose a moratorium on state cap and trade programs from 2012 to 2017.

For New Source Review (NSR), the project aggregation (final action) was issued in the final days of the Bush Administration. In February, EPA stayed the effective date to May 2009. In May, EPA delayed the rule to May 2010. During this delay, EPA will reconsider the rule. The rule covers facilities that combine activities that are "substantially economically or technically related". Aggregated changes must have more in common than supporting an overall basic function. Timing by itself is not a basis for aggregation. Projects occurring more than 3 years apart are assumed not to be substantially related. In addition to aggregation, EPA agreed to reconsider NSR provisions on record keeping, inclusion of fugitive emissions, and PM_{2.5} permitting.

EPA issued a rule in 2007 that required a source to keep certain records for changes that did not trigger NSR but projected an emissions increase to be more than 50% of the NSR significance level. For fugitive emissions, EPA promulgated revisions in December 2008. In the new policy, fugitive emissions are to be included in determining NSR applicability only if the facility is one of the 28 listed source categories, or is subject to an NSPS or NESHAP. A stay has been granted for more public comment.

On PM_{2.5}, EPA is reconsidering four parts of the final PM_{2.5} rule of May 2008. A new transition schedule for state approved PSD programs is effective with states having 3 years for SIP revisions incorporating PM_{2.5}. "Grandfathering" of permit applications before July 15, 2008 has been placed under administrative stay. Exclusion of condensable particulates is allowed until Jan. 1, 2011. In March, EPA proposed new test methods for filterable PM₁₀ and PM_{2.5}, as well as condensable PM. These are Proposed Method 201A (Cascade Impactor Method) and Proposed Method 202 (Dry Impinger Method). There is a major concern with EPA's proposal to shorten the transition period.

CAIR is still in effect, but EPA must develop a replacement rule. The NO₂ NAAQS revisions were published in the Federal Register on July 15th. The current annual average standard is 53 ppb.

The proposed new 1 hour standard is 80 - 100 ppb, with EPA requesting comments on levels from 65 ppb up to 150 ppb. The average annual and secondary standards would remain unchanged. Attainment for the new 1 hour standard would be January 2022.

The MACT SSM Exemption is based on a source's "general duty" to minimize emissions during startup, shutdown, and malfunction events. In December, 2008, the DC Court vacated the exemption. However, the vacatur is not yet in effect pending the procedural issuance of a mandate by the court. EPA has issued guidance on July 22, 2009. Vacatur affects only MACT standards that incorporate the SSM exemption by reference and contain no other language that provides SSM protections.

II. Stoker Workshop - Bob Bessette, CIBO

Stokers, like all boilers, each have their own personalities. No two units are exactly alike. Differences in supplier philosophy, fuels, operations, design considerations, and regulatory requirements make for different units. A brief, around the room, survey of topics produced the following list:

- technology developments
 - alternate fuels (5 responses)
 - meeting new environmental standards with existing boilers (5 responses)
 - control devices (3 responses)
 - sorbent injection
 - mercury control
 - manpower (operators) (4 responses)
 - sludge burning
 - efficiency improvements
 - ash (quantity and carbon content) (2 responses)

With each boiler having its own idiosyncrasies, it takes a new operator 2 - 3 years to learn how to operate the boiler consistently under all load conditions, start up, shut down, and emergency situations. Many older units did not have economizers or air heaters. The furnace outlet temperatures from such units is necessarily higher than units equipped with this equipment. That means that typical back end equipment designed for 300 F gas temperature will have problems with 450 F gas.

Fuel handling, fuel sizing, moisture content, and fuel feeding have a significant impact on stoker grate performance. Fuel mixing, co-firing, and supplemental firing all produce differing combustion and heat transfer performance. Part of the learning process is to find out what others are doing with similar type stokers. CIBO will send out a survey to members to identify types of stokers so the members can share experiences. European experience with a wide variety of fuels and additives have led to design changes in new units.

III. Owner & Operator Forum – Ann McIver, Citizens Thermal, Facilitator Equipment Suppliers Forum - Vince Albanese, Fuel Tech Inc., Facilitator

See Review of Concurrent Sessions to Follow

IV. Review of Concurrent Sessions - Fred Fendt, The Dow Chemical Company, Moderator

Peter Finnis of Solvay Chemicals Inc. reported for the suppliers meeting. The economy is difficult right now. The suppliers have been doing studies, but there are very few projects. The level of uncertainty in fuel costs, regulatory requirements, and financing makes it very difficult to plan for a project. CO₂ is driving interest in biomass and efficiency improvements. A very few companies are coming up with CO₂ capture processes. The infrastructure for CO₂ sequestration is not in place to drive widespread application. There was considerable discussion about PM_{2.5} and

condensable particulates. The new methods pick up both organic and inorganic condensables. Preliminary data has indicated a roughly 50/50 split. Regulatory certainty would be a nice goal.

Melinda Deluca of Miller/Coors reported for the owners. The first comment is that "we don't know what we don't know". Many owners are in the situation that they are not familiar with what they need to do. This is especially true for the smaller natural gas fired units which have not traditionally been regulated. The industry is losing experienced and trained people. This is making it more difficult. We need to work through CIBO to gain some regulatory certainty and reasonableness. It was also suggested that sharing of data amongst the members may be one way help work through this situation.

Communications tools and vehicles would be helpful to all CIBO members. The breadth of the problem is the number of rules and regulations that appear to be coming and the uncertainty of when these rules really do come final. Many companies prepared for the first issuance of the Industrial Boiler MACT and installed controls in plenty of time to be in compliance, only to have the rule vacated by the court. The CAIR rule, the CAMR rule, several NSR rules, and the SSM rules all have been vacated by court rulings.

V. Environmental Rules, Regulations and Implementation in the Industrial Sector - Panel

The panel consisted of **Jim Eddinger**, US EPA; **Andy Bodnarik**, NH Dept. of Environmental Services; **Marc Cone**, State of Maine; **Bob Fraser**, AECOM; **Cindy Khalaf**, **Johnson Matthey**; and **Bob Ellerhorst**, Michigan State University.

Jim Eddinger of US EPA, reported on the status of the Industrial Boiler MACT rule. The intention had been to report on the rule, but the July 15th deadline was extended to Sept. The Boiler rule will apply to "large" boilers. The Area Source rule will apply to small boilers. The EPA is still negotiating with the litigants in order to take into account the additional data that is due Oct. 15th. Further, the definition of what constitutes a solid waste has to be finalized so that units can be categorized properly. This is critical since the vacatur was based on the problem associated with the CISWI rule covering incinerators. A unit that burns any waste is defined as an incinerator. In order to get a better handle on the data, EPA sent out ICR requests to some 3500 facilities for survey information. This was followed by a second phase focusing on data gaps for an additional 300 units. The survey data indicated that many industrial units no longer burn oil. If the 300, 64 had to be changed due to shut downs or fuel changes that made the unit no longer applicable for the data. Replacements were found for these units with the need for an extension of submittal dates. The purpose of collecting the data was to better categorize the units by type of fuel and type of boiler. Proper choice of surrogates will depend on the data. Standards for all HAP on all types of units is a question for the lawyers. The HBCA issue is still open.

Andy Bodnarik, speaking for the Ozone Transport Commission (OTC) and the North East States Coordinated Air Use Management (NESCAUM), reported on the study for Control Cost Estimates for ICI Boilers for NO_x and SO₂. The states had been trying to use CUECOST (developed by EPA using utility data) for cost estimates for control systems on industrial. For NO_x controls, a wide gamut of control technologies from low NO_x burners up to full SCRs. For SO₂ control, a variety of wet and dry FGD systems were evaluated. Key variables include boiler type, fuel type, firing system, current emissions, target emissions, capital cost, financial costs, interest rates, utility rates (water, electricity, etc.), and time horizon. Assumptions for instrumentation, sales taxes, freight, direct installation costs, indirect capital costs, direct operating costs, and indirect operating costs were made based on recent reported data.

The resulting data illustrated the trends with unit size, type of fuel, and degree of reduction. The system is set up on spread sheets using EXCEL. Typically, the same control technology shows a higher cost per ton removed on smaller units burning cleaner fuels as the starting emissions levels are lower and fewer tons are removed. Larger units with solid fuels benefit from economies of scale and higher levels of reduction giving a lower cost per ton removed.

The OTC has been looking at controls on ICI boilers because the states are still having trouble meeting attainment for ozone and fine particulates. Having installed controls on EGUs, the next large class of units becomes the ICI boiler community. NO_x emissions from area sources in New England are now the largest source. In a number of areas, the SO₂ emissions and point sources are roughly equal in emissions inventory. Area sources are typically less than 50 MMBTU/hr. In the LADCO states, coal fired boilers and large boilers dominate the emissions. In the OTC states, there is a lot more oil and gas firing (72% of NO_x) and a lot more small boilers. Most of the large units (>250 MMBTU/hr) have already installed controls. These units are no longer the major contributors.

Since the states still have attainment issues, additional control strategies are needed. The OTC is looking at requirements for units greater than 25 MMBTU/hr in size. Some states may be looking at smaller units (possibly as low as 10 MMBTU/hr). On the SO₂ side, low sulfur fuel will likely be the strategy for small units. In looking at strategies for these units, the cost estimates from the spread sheets were used to try to determine a cost effectiveness for a given strategy. Costs and emissions were reported by area. Air quality impacts were modeled for the Great Lakes region. Modeling of other regions is planned. The 14th draft of the Technical Support Document is under review. A recommendation will be transmitted to EPA. The OTC will meet with the stakeholders to review the data.

Marc Cone, from the State of Maine, reported on some of the issues that are “up in the air” in the State of Maine. In 2010, the state expects a new ozone standard. A 3 year period follows for SIP plans. Additional modeling will be required. A new NO_x budget will result. There will also be a particulate RACT requirement. The CAIR rule will be revised. It is likely that large industrial units will be included. For Regional Haze, the BART rules will apply. Additional modeling will likely be required. Lower sulfur in fuel oils will be required for #2, #6, and home heating oils. Residential heating using wood or pellet burning stoves has increased. These contribute to the haze issue. The Boiler MACT and CISWI issues are still in the fore.

The NACAA proposal for very low CO limits will be nearly impossible on some of the smaller units and the wood fired units. The state has requested more information from existing units to get a better feel for the data. The relationships between CO and NO_x are of concern. The state has made a concerted effort to reduce NO_x and is concerned that a drive to much lower CO levels will impact the NO_x performance. There is considerable variability in CO data with biomass firing. This can be stabilized somewhat in co-firing with fossil fuels. Biomass has variable moisture content, which can lead to changes in gas flow rate and then impact performance. Generally, NO_x shows an inverse relationship with CO. VOC data has similar issues. One wood fired unit showed CO variability on the order of 1000 ppm.

There are also new NSPS for engines. There is some confusion about these rules, particularly for gasoline powered engines. Diesel engines are more understandable. For the 10 Northeastern states, the RGGI requirements for CO₂ will impact many units unless the Waxman Markey bill passes the Senate and the state initiatives are suspended.

Bob Fraser of AECOM, reported on some of the aspects of future industrial boiler plants. Taking a hypothetical industrial plant with 2 stoker boilers burning coal and 2 gas fired boilers. During the economic downturn, the gas price is down and only one stoker is being operated at part load. Cost cutting initiatives have resulted in 2 of the stoker operators taking an early retirement package. Management has suggested that the stokers be shut down, but the power house is concerned that the price of gas will go back up to high levels as it did just one year ago. Once the coal units are gone, they will be very difficult to get back. Management is looking for a 10 or 20 year plan for the industrial boiler capacity at the plant. Questions such as the ones below will all need to be addressed in some way.

Can we still burn coal?

Will we have a MACT rule this year?

Can we meet all of the HAP rules simultaneously?
Will we need mercury control?
Will we need HCl control?
How much will we have to pay for CO2 allowances?
Should we add biomass firing?
Should we convert to natural gas?
Should we budget for more capital and operating expenses?
While the answers may not be clear, they still need to be considered.

Cindy Khalaf of Michigan State University, reported on the ICAC (Institute of Clean Air Companies) recently issued white paper on SCRs and how the ICAC distinguishes between utility and industrial applications. There are several companies that are associate members of CIBO and members of the ICAC. SCR technology is available for both utility and industrial boiler applications. SCRs can be located in different parts of the overall clean up system. In utility applications, it typically is located where the gas temperature is about 750 F. This is a high dust environment, but is the location where the catalyst is most active. Other locations trade off catalyst activity with gas cleanliness and ease of location.

The ICAC white paper was first published in 1997 before many units of any kind had been using SCR. The first version was very basic and provided mostly information focused on utility boilers. Now that many more installations have been realized, an update was issued in May of this year. Recognizing that industrial applications have some differences, an addendum is planned for later in the year specifically addressing Industrial, Commercial and Institutional (ICI) applications. One of the issues for SCR is the formation of ammonium bisulfate at back end temperatures due to the reaction of ammonia and SO₃. Catalyst poisons include phosphorus, arsenic, potassium, and sodium. Ammonia slip on utility units is typically 2 ppm at end of catalyst device. Catalyst development is aimed at minimizing the oxidation of SO₂ to SO₃, encouraging mercury oxidation, and extending catalyst life. There is a lot of information in the white paper that is applicable to industrial units. The addendum is looking at regulations that apply to ICI units, fuel types and variability, temperature differences, differences between utility and industrial boilers, variability in operations, mixing and flow characteristics of the gas, urea vs ammonia gas, vs aqueous ammonia, and cost basis. Additional specific applications include engines, industrial boilers, MSW, and other fuels. Historically, the organization has set up around the compounds of interest (ie NO_x, SO₂, Hg, particulates, acid gas, etc.). During the past year, the organization has started to have meetings that segment by market, including industrial and utility markets.

Bob Ellerhorst of Michigan State University, provided an owner's reaction. Michigan State University is a \$1.3 billion dollar operation. A \$7 million increase in budget results in a 1% increase in tuition. The power house is the sole source of heating and cooling on the campus. The total load is 1 million pounds of steam and 100 Mw. Boiler steam pressure is 900 psig. Of the owners in the audience, there were several that had gotten ICR letters requesting tests. Of those, only Michigan State had finished their testing. The e-mail access works. The university joined the Chicago Climate Exchange for CO₂. However, some of the alternate fuels cannot be classified at this time as to whether they are potential fuels or potential wastes. With regard to low sulfur oil, the infrastructure and supply chain issues for the Northeast appear to be the main ones. Fuel blending to meet a sulfur spec tends to be primary supply. Developing lower sulfur fuel supply will add to the cost. NO_x reductions cost the university over \$4,000/ton. One of the interesting trade offs to consider for CO₂ was to turn off the NO_x controls and increase the combustion efficiency and the boiler efficiency. This reduces the CO₂ at the expense of the NO_x. The question will be the cost of CO₂ allowances vs the cost of NO_x allowances. Coordinated decision making will become increasingly difficult. Decision making under uncertainty will be required.

VI. Particulate and Multi-Emissions Control Technologies for HCl, SO₂, and Hg - Sean McMenemy, Peerless Mfg. Co., Moderator

The panel consisted of **Tim Shippy**, Peerless Mfg. Co.; **John Wallace**, FMC Corporation; **John Boyle**, Fuel Tech, Inc.; **Mike Booth**, GE; **Joseph Shulfer**, Eisenmann Corporation; **Stacey Edwards**, Cornell University; and **Bobby Chen**, Shaw Environmental, Inc.

Tim Shippy of Peerless Mfg. Co., noted that Peerless got started on SCR for NO_x control in the 1980s. The California market started with gas turbines and refinery applications. This was followed by the major ozone non-attainment areas looking to reduce NO_x. In the late 90s, a gas turbine boom drove a major increase in the SCR market. This was accompanied by a retrofit market on existing coal fired units. The dot.com bust was also accompanied by an increase in gas prices, which ended the gas turbine boom. SCRs have been put on MSW units in Europe and that experience is migrating to North America. Most SCR applications specify 70-90% reductions. Ammonia slip requirements are becoming more stringent. Most industrial applications use aqueous ammonia as the additive. A recent installation on a 125,000 lb/hr gas fired boiler in Massachusetts required 2ppm NO_x and 2 ppm NH₃ slip.

John Wallace FMC Corporation, reported on the utilization of alkalis for acid gas scrubbing. There is a major source of trona in Wyoming, which is the primary source of sodium based sorbents. With the additional attention to smaller units with SO₂ emissions, the potential market for alkali scrubbing has increased. Moderate sized utility units that are older are one market segment. Industrial boilers represent a major market. The relatively high cost of wet FGD systems for smaller industrial boilers makes the potential dry trona injection system attractive. Dry injection of trona can achieve up to 90% sulfur capture, as well as HCl and other acid gases. Typical injection points are just in front of the air heater and in front of the particulate removal system. Rapid calcination of the trona produces a material that has an exceptionally high surface area. Sodium sulfate and sodium chloride are the reaction products. The dry injection system gives a relatively low equipment cost at the expense of more operating costs. Milling the powder to finer size can reduce the amount of material that is needed. Questions about fly ash characteristics remain to be quantified.

John Boyle of Fuel Tech, Inc., reported on layering of NO_x solutions for industrial applications. The goal is to identify synergies amongst the various technologies for control. The various systems for NO_x control include combustion controls and post combustion controls. These are primarily low NO_x burners, overfire air, SNCR, and SCR. These can be combined in various ways in an effort to improve the performance of both types of systems.

Low NO_x burners are low capital and low operating costs. A limitation is the combustion efficiency of the system. Overfire air systems are also low capital and low operating costs. With optimal mixing, it may be possible to reduce the total amount of excess air. An SNCR system is a low capital cost, but high operating costs. Limitations include reduction levels, ammonia slip, and bisulfate formation. SCR is a high capital, high operating cost system. Higher reduction levels can be achieved. The catalyst can oxidize SO₂ to SO₃. There are still concerns about ammonia slip and bisulfate formation.

Combustion tuning provides the opportunity for optimizing the input parameters to obtain the best performance. Target gas temperatures for SNCR range from 1500 F to 2200 F. For SCR, the optimum temperature is 750 F. In order to optimize SNCR performance, computational fluid dynamic (CFD) modeling, chemical kinetic modeling, and injection modeling are needed. There are over 450 SNCR installations, the vast majority of which are industrial applications. Layering these technologies is a way to reduce overall risk. By lowering the baseline of NO_x going into the catalyst, the amount of reduction required is lower and, thus, the amount of catalyst required. Moderate low NO_x burner and overfire air systems, coupled with an SNCR system with some ammonia slip, will allow for a much smaller SCR system for the same outlet NO_x requirement.

For each situation, there is an optimal balance for these systems that maximizes performance and minimizes risk.

Mike Booth of GE, reported on blending technologies to address industrial boiler MACT. Compliance strategies for a given species will potentially impact the performance of other species that may be regulated. For typical industrial boilers, strategies cover particulate controls, chloride controls, mercury controls, and CO controls. Of these, the first 3 are primarily involved with some kind of back end controls. Each affected site will have its own compliance plan.

When evaluating an engineering strategy, draw the boundary lines widely, so that all of the potential issues can be identified. High alkali ash material can cause metal migration in a landfill. That means that fly ash with high concentration of alkalis may not be acceptable to a landfill. One example, was a limestone, furnace sorbent injection system. Care was taken to make sure that slagging and fouling would not be a problem with the particular coal in question. An application for the alkaline ash material was found. When the system was operated, the SO₂ reduction was in line with expectations, in the neighborhood of 60 - 65%. However, it was also noted on the mercury CEMS that the mercury level in the gas was substantially reduced. It was postulated that the calcined limestone offered some sites for mercury absorption. Use of some of the 6 Sigma tools in process evaluations helps to assure that all issues are considered. Hydrated lime was used for an HCl reduction application. Both bromated and non-bromated hydrated lime was used. Activated carbon is used for mercury. There is not a lot of data on arsenic and selenium, but activated carbon can absorb some of these compounds. Hydrated lime also will absorb these materials.

Joseph Shulfer of Eisenmann Corporation, reported on emerging technology for multi-pollutant controls. Solid fuel systems generate particulate matter, SO₂, SO₃, HCl, NO_x, Hg, and CO. A wet electrostatic precipitator system with 2 zones. A first zone quenches the gas with water sprays to reduce the temperature and saturate the gas. An upflow scrubber then removes acid gases. This is followed by the wet EPS that has two fields. A small amount of ozone is used to oxidize some of the NO and Hg so that these compounds can be better collected. Blowdown from the boiler system is combined with the blowdown from the scrubbing system to be used as make up water for the scrubber. The system has been used on a 500 HP boiler rated at 100,000 lb/hr steam flow. Wood chips and coal provide the fuel to the boilers. A prototype system is available that can be portable. Recent test results showed good performance on SO₂ and SO₃ (95 - 99%), particulates (99+ %), and NO_x (over 90%).

Stacey Edwards of Cornell University, reported on the mercury testing program at Cornell University. The combined heat and power plant cogenerates about 8 Mw with a steam load up to 400,000 lb/hr in the winter and 60,000 lb/hr in the summer. The base coal fired boiler is a 1949 vintage Riley traveling grate stoker. The mercury content of the coal was originally higher than the MACT limit at the time and mercury control was anticipated. In the last few years, the mercury content of the coal has been under the limit. Since the coal comes from the same source, there is no particular explanation for the change. Tests were done in 2005 without activated carbon and native capture on the flyash was measured at 30%. An activated carbon system was installed and testing was done on both activated carbon and brominated activated carbon. The measured capture was 30%. Other tests indicated that the SO₃ level was fairly high. The SO₃ competes with mercury for sites on the activated carbon. Since the SO₃ at 10 - 15 ppm is much higher in concentration than the mercury, little mercury capture is obtained. In 2008, Cornell University received a grant from NYSERDA to investigate potential improvements. An advisory team was formed to review the data and make recommendations. Reduction of the SO₃ concentration was recommended to help the activated carbon system. This could be done either with additives or by reducing the excess air or both. The changes to the boiler and the boiler tune up were not funded. Trona injection was selected for SO₃ control. Aqueous ammonia was also tested. The additives were both successful in reducing the SO₃. During such tests, the mercury removal went up to 90%.

During a planned extended run, the capture performance dropped off with the ammonia. The ammonia pump dropped off after about 18 hours. Then the weather warmed up in the middle of winter and the plant went to very low load. There was no variable control on the ammonia and the ammonia was overfed for 4 hours. Excess hot ash was observed. There might have been an ash fire in the baghouse. The carbon in the ash is relatively high averaging 20% and perhaps up to 40%. The gas temperature into the baghouse was not high.

Bobby Chen of Shaw Environmental, Inc., reported on post combustion control system evaluations. Shaw does A/E work for power plants. Theoretically, for every 1000 ppm of SO₂, there is 6 - 7 ppm of SO₃. Chlorides in bituminous coal, range from 1000 ppm to 4000 ppm. In sub-bituminous coals, there is less than 100 ppm. In lignite, the range is 100 - 400 ppm. For every 1000 ppm of chloride in the coal, there will be 100 ppm in the gas. Mercury in coal is vaporized. During the course of travel through the unit, some mercury is oxidized. HCl in the gas, assists in the oxidation of the mercury. Oxidized mercury tends to bind with the flyash. Elemental mercury does not bind with flyash and is not soluble in water. An SCR will oxidize mercury in the presence of HCl and HBr.

Particulate control systems are typically electrostatic precipitators (ESP) and baghouses. Baghouses provide a filter cake that assists in the capture of mercury. Wet scrubbers can absorb oxidized mercury. Forced oxidation systems can cause mercury readmission from mercury dissolved in the scrubber solution. Coal variation from the same mine can be as high as 300% for mercury in coal. It is important to understand the variation of mercury in the coal to understand what is going into the boiler.

An Enhanced Mercury Oxidation System is being developed to improve the collection of mercury in the system. Many activated carbon systems are impregnated with bromine to improve the oxidation of mercury. The enhanced oxidant can be introduced in low levels to help oxidize mercury and NO. Trona injection for acid gases can remove SO₂ and SO₃. The result of SO₂ reduction gives some mercury capture as well. The oxidized NO to NO₂ that becomes water soluble can be absorbed on the trona. However, if a wet scrubber is used, the soluble nitrites and nitrates will build up in the scrubber solution requiring some kind of blowdown or water treatment system.

VII. Short Course on Fundamentals of Burner Design, Timothy Webster, Coen Company/Todd Combustion

Tim Webster of Coen Company/Todd Combustion provided a short course on the fundamentals of Gas and Oil Burner Design. The 5 Ms of burner design are to meter the fuel and air, mix the fuel and air, maintain ignition, mold the flame and minimize emissions. The burner components that allow the manufacturer to do this are: one or more air registers, some form of a flame holder, gaseous fuel injectors, an oil atomizer, an igniter and the burner throat. Variation on the design of each of these and how they provide the fundamentals of individual burner manufacturer designs. A range of emission reduction techniques is available for the burner manufacturer including: flue gas recirculation, air staging, fuel staging, pre-mix combustion and rapid mix combustion. A combination of these may be needed as emissions limits approach 30 ppmv and most likely be needed when the limits go below 10 ppmv NO_x.

VIII. Boiler Testing Tune Up Monitoring Panel – Phil Midgett, Airgas. Moderator

The panel consisted of **Phil Midgett**, Airgas; **Mike Hartman**, Air Tech; **David Ozawa**, Platt Environmental; **Larry Fisher**, Ashtead Technology; and **Dan Todd**, Air Quality Services, LLC.

Phil Midgett of Airgas, noted that air pollution fines are not pleasant. There is a new administration and new people at EPA. In order to reduce the likelihood of getting a fine, Airgas has come up with 10 suggestions to help. The first makes everyone responsible. This means getting everyone onsite involved.

The second is review your permit.
Third is get to know your inspectors. It makes communications easier.
Fourth is take advantage of the EPA website for information.
Fifth is attend appropriate compliance seminars.
Sixth is keep up with the EPA through their on line notification system.
Seventh is quiz your suppliers on potential problems that could cause trouble.
Eighth is be proud of your compliance. Post your performance.
Ninth is choose your stack tester very carefully. Follow up with their references. Take advantage of the Source Evaluation Society.

Finally, get your customers involved. This demonstrates your commitment.

Commitment

Communications

Confidence

Compliance are the 4 C's for avoiding fines.

Mike Hartman of Air Tech, reported on the EPA 114 (ICR) testing. EPA has sent letters to gather data for the boiler MACT promulgation. The data that is generated will be used to formulate the regulations that will apply to your plant and other plants that are similar. The data requests are meant to fill in gaps in EPA's data. These are to determine emissions, to determine variability, to help identify categories, and to help qualify (or disqualify) surrogates. The emissions test request identifies the facility (with name and address), the unit ID, the design capacity, the fuel, the control devices, and the test type. Make sure the information is correct.

An example test type requests CO, hydrocarbons, formaldehyde, methane, PM, Hcl, HF, Hg, metals, dioxins, NOx, SO2, stack test, and 10 samples fuel variability. The data to be provided needs to be repeatable and reproducible (ie scientifically sound). Requirements are a good testing firm, a good laboratory, and a good test plan. The data will be reported electronically in EPA's new test form (ERT). The emissions test template is also included with the letter. All concentrations are to be reported at 7% O2. This means that oxygen measurements will also be required. Method 0028 and PM2.5 are also required. This requirement means that both total PM and PM2.5 will have to be measured. Fuel quality will be important. Fuel variability applies to high sulfur, high chlorine, high mercury, etc.

Getting repeatable and reproducible data depends on using repeatable and reproducible fuel. If sootblowing is used, at least one test must be done with sootblowing. Procedures and methods are reviewed under guidance document 51. The guidelines are available on the EPA website. For oil firing, the fuel analysis including metals in oil, chlorides in oil, sulfur in oil, etc. can be used in lieu of stack testing when there are no control devices. Good laboratories are needed. They need to have demonstrated capability in the required analysis methods for your tests.

Detection limits present a problem. Standards should not be sent to non-detect limits. These may not be repeatable or reproducible. Sampling time influences what can be detected. Most requirements are for 2 or 4 hours. The CEMS needs to be run simultaneously for the period of time required by the particular compound.

Testing firms should be using the appropriate ASTM standards and have a QA/QC program. Experience in this type of testing is appropriate. Individual test personnel should have passed the QSTI test (qualified source test individual). In addition, 1 year of experience in this area of testing and appropriate recommendations are required. Documentation is a key feature of the quality requirements. The method detection limit is higher than the instrument detection limit. The instrument detection limit merely applies to the instrument. The quantitation detection limit applies to the sampling time and the operational issues and is roughly

3 times the instrument detection limit. The method detection limit includes the variability in all of the elements associated with the method, sampling, and operation and is roughly another 50% higher than the quantitation limit.

David Ozawa of Platt Environmental, reported on Boiler MACT and Greenhouse Gas Reporting. Data gathering for these programs has widened the scope of required data. The utility boiler ICR has requested even more compounds including radio nuclides, hydrogen cyanide, and other potential HAP. Detection limit issues are driving up sampling times. Utility sampling times of up to 8 hours are being required. By doubling the sampling time, the detection limit is reduced by 50%. The implication might be that the MACT floor would be different for utility and industrial boilers for the same compound. This leaves open the question of how long this will be allowed before someone proposes to make the same lower floor for both.

Key test issues include preparation, test location, power supply, fuel quality and consistency, and operational conditions. The GHG reporting rule went out for public comment and is due to issue as a rule. Reporting would be done in 2010. This data will be used to set the baseline for any tax or cap and trade program. Any facility that is close to 30 MMBTU/hr should start doing the calculations to determine if they trigger the 25,000 ton/yr CO₂ equivalent trigger. GHG reporting is not the same as the carbon footprint. However, purchased electricity and steam are counted. Also included are most refrigerants (except ammonia) and fire suppression systems. Mobil sources are based on fuel use and mileage. Biogenic fuels do not count as GHG generators. Reporting is required quarterly on a per unit basis.

Larry Fisher of Ashtead Technology, reported on hydrocarbon sampling methodology. EPA Methods 1 - 4 cover sampling and velocity traverses including location requirements. An S-type pitot tube is specified. The gas analysis and dry molecular weight are needed to make corrections to the flow measurements. The moisture content is required to correct between wet and dry volumes. Simultaneous wet methods are to be used. EPA Method 25A covers the determination of organic compounds in gases. A flame ionization analyzer is used with appropriate calibration gases. A heated probe with a sintered filter (down to 10 microns) is used along with a pump and an analyzer. A stainless steel probe is normally used (good to 1200 F). The heated sample line must be kept above 220 F. Most are run at around 280 F. There are a number of Flame Ionization analyzers. Some units use a gas chromatograph column to separate methane from the total hydrocarbons to get the methane. These units have a longer sampling time than some of the other units (although they are the most common). The analyzer works by having an open flame that burns the hydrocarbons in the sample. A high voltage electrode ionizes the elements of the flame driving ions to the collecting electrode. The current is proportional to the hydrocarbon content. The calibration gases are typically propane in air or propane in nitrogen. If methane is measured separately, methane in air or nitrogen calibration gas will be needed.

For compliance testing, 3 one hour runs are required. Instrument scale should be on the order of 1.5 or 2 times the expected value. If the expected value is 50 ppm, the scale should be from zero to 100 ppm. High, medium, and low calibration gases will be required. During the calibration test, the high level gas is tested and set for the instrument. Then the low and medium cal gases are sent and checked against the instrument. There should be agreement to within 3%. For FID analyzers, the sample is read hot and wet. FID analyzers are sensitive and finicky. Humidity and vibration will impact the results. Sitting in the sun will cause drift. They take about 2 hours to "warm up" and stabilize. Chlorinated hydrocarbons give non linear responses. A calibration curve will be needed for such compounds. Heated sample lines have lots of bias. Sample lines need to be especially clean, particularly for values less than 30 ppm. Particulates will foul the device and impact the results. Making sure the flame is lit involves some positive actions. Disconnecting the sample line and putting a "Sharpie" marker near the inlet should cause an immediate response from the system (ie peg the meter). On the outlet, a piece of glass should fog up from the gas moisture level. Electrical requirements include 4 x 20 amp circuit. The best operators should be running the unit during the sampling. Stay away from the ash doors. Communicate any upsets or problems. The oxygen level in the flue gas should be close to oxygen level in the calibration gas.

Dan Todd of Air Quality Services, LLC, reported on proposed amendments to EPA Methods 201A and 202. These new methods are intended to get PM10, PM2.5, and condensables. Due to the added requirements, costs are likely to go up.

Method 201A determines PM10 (filterable) and total particulate (filterable). Method 202 determines the condensables. In Method 201A, a cyclone separator is used in the stack to separate the larger (>PM10) particles from the rest. The modification proposes to use a second cyclone which will take out particles larger than PM2.5. The larger test equipment will likely mean that 4 inch test ports will no longer be adequate. This train is referred to the "front half". The "back half" now concerns the condensables. Method 202 utilizes an impinger system to condense out the condensable particulates. A condenser is proposed to be added between the filter and the first impinger. A nitrogen purge is recommended after each test to remove any artifacts before the next test. Preparation is more complicated. The glassware must be cleaned and baked for 6 hours at 300 C. The purge is mandatory. The glassware has various rinse requirements. A sampling protocol has been developed to assure proper treatment. The potential artifacts come about from gases that would remain a gas when emitted to the atmosphere but would condense in the impinger train and be counted as condensable particulate. A universal outcome will be increased time for the tester and increased cost to the plant owner.

IX. ABMA Gas and Oil Fired Burner Manufacturers - Bill Testa, CoenCompany/ToddCombustion, Moderator

The panel consisted of **Tim Webster**, CoenCompany/ToddCombustion; and **Rick Fiorenza**, CB/Natcom.

Rick Fiorenza of CB/Natcom, reported on alternative fuel burners for industrial units. The types of fuels include biogas, refinery gas, landfill gas, hydrogen, flammable liquids, and waste oils. Landfill and digester gases can be utilized. Sulfur content is a concern. Some of these gases contain H₂S which presents safety, corrosion, and emissions concerns. The heating value is roughly half that of natural gas, so twice as much gas has to be processed. Another 30 - 40% of the gas is CO₂. Refinery gases consist of many hydrocarbon fuels. Variability is the key issue. Waste oils and flammable liquids range from 50,000 - 100,000 BTU/gal. The issues with these fuels are usually upstream or downstream. The combustion part is not the hard part, with the exception of variability. Knowing the fuel is very important so that the handling, safety, and corrosion issues can be addressed.

Simultaneous firing is one way to deal with variability. One fuel is base loaded and one fuel modulates to accommodate the variability. In "preferred" firing, one fuel may be preferred in the sense that as much as is available of a particular fuel may want to be consumed. A control system that adjusts the base fuel to the variation in the preferred fuel can be utilized. At one chemical plant, a low BTU tail gas (85 BTU gas) was consumed along with natural gas. At a refinery, a 150,000 lb/hr boiler making 275 psig steam utilized refinery gas with a heating value of 28,000 BTU/lb. Controlling the air flow is needed to meet NO_x requirements.

Hydrogen is a very fast burning fuel. The unit used hydrogen, fuel oil, and natural gas for fuel. A preferred fuel strategy was used to consume the hydrogen using the other fuels as the base fuel. Biofuels include vegetable oils and other liquid compounds that are either dissolved or emulsified with the oil. Some of these are now being tested. Successful projects understand the plant process and requirements and provide appropriate engineering and controls to meet the demands.

Bill Testa of Coen Company/Todd Combustion, substituted for Tim Webster who was taken ill this morning and gave some case studies on alternative fuel burners. Some solid fuel firing can be accommodated with the Coen dual air zone burner. Projects have included peanut shells, rice hulls, oat hulls, sawdust, and other woody wastes. Air staging using adjustable air ports can be

used to minimize NO_x formation. Flue gas recirculation can be used to further reduce NO_x. Resins and glues tend to be relatively high nitrogen bearing compounds.

A window manufacturer installed 2 x 40,000 lb/hr, D-type, package boilers using sawdust from a pressed board facility. A sustaining fuel of about 5% was used (natural gas). The sawdust was relatively high in nitrogen. The NO_x requirement was 0.2 lb/MMBTU. Metering bins were used to feed the fuel. A fiberboard plant in Brazil had 2 x 60 MMBTU/hr burners to handle sander dust over the grate, which handles wood waste. Good flame shaping is needed to keep the flame within the appropriate confines of the boiler. The burners had to be run independently. There was a requirement for no sustaining fuel. The burner manufacturer requested the dust be dried to 1% moisture. The unit started up successfully. Moisture levels up to 8% have been observed. Waste fuel firing in duct burners has been successfully applied. In one case, natural gas and syngas was requested for a duct burner application for an combined cycle plant at a refinery. Natural gas, diamine offgas, and hydrogen would be the fuels. A VOC waste stream was also to be utilized. The fuels were metered to a steady heating value for the mixture. This mixed fuel was fed to the duct burners. The VOC stream was introduced with the air. Utilizing refinery gases must consider the potential for coking of some of the higher hydrocarbons if the duct temperature gets too high. Hydrogen, offgas, and natural gas are mixed to provide a constant heating value gas stream to the burner system.

X. Multi Pollutant Reduction on Industrial Boilers - Jay Crilley, Nalco Mobotec

The key pollutants for industrial boilers include NO_x, SO₂, CO, mercury, HCl, particulates, and possibly CO₂. There is an array of NO_x control technologies that trade off reduction performance with capital costs. For SO₂, there are a number of technologies including furnace injection that generally get fairly high reduction levels. For mercury, native collection, mercury oxidation, and activated carbon are available. For mercury oxidation, a halogen (typically) can be injected into the furnace to increase the level of oxidation of the mercury. The mercury is then collected in the ash. Comparisons with activated carbon indicate that injection of the halogen reduces the amount of activated carbon that is needed to reach 90% mercury capture.

SO₃ interferes with mercury adsorption on activated carbon. Oxidizing the mercury ahead of the activated carbon produces the oxidized mercury that can be collected as a particulate. Improving the combustion process can reduce the amount of flyash, the amount of flue gas, and the amount of SO₃, which will help all of the control processes.

For HCl, dry sorbents or dry FGDs get good chloride removal. Wet scrubbers remove some chlorides as well. The increased interest in biomass for CO₂ reductions poses some additional issues. These typically involve handling and injecting the fuel. Biomass is typically low in sulfur and low in nitrogen. As a result, with successful biomass operation, SO₂ and NO_x emissions can also be reduced with biomass firing. At another stoker unit, the addition of ROFA (rotating overfire air) and limestone resulting in 60% NO_x reduction, 87% sulfur reduction, and 92% mercury reduction.. This unit has a baghouse which enables the bulk of the sulfur reduction. The fuel has relatively high chloride content which enables the oxidation of the mercury. The added calcium and the filter cake on the baghouse provides for additional capture.

XI. Alternate Biomass/Alternate Fuels - Tom Sarkus, NETL

Tom announced that Don Bonk of DOE is doing well and sends his regards to the CIBO members. Biomass is considered to be green. Fuel blends tend to be considered green. Co-firing can be considered green but may have some specific issues. The reasons for fuel blending include supply, economics, environmental, and regulatory. Common blends include coal and biomass, waste coal and biomass, bituminous coal and petcoke, PRB and lignite, and other blends.

Performance issues include differences in the coal as well as the biomass. The guiding principles are that fuels are unique and that blends of fuels create another unique fuel. Blending Appalachian coal with 5 - 20% wood show changes in heating value, base to acid ratio, iron to calcium ratio, and potentially ash fusion temperature. This could lead to slagging and fouling problems. Each blend is unique and needs to be considered on its own terms. Blending can be done in a number of locations including the hoppers, the feeders, and the boiler. Fibrous biomass can cause difficulties with handling systems. Transport velocities need to be kept above the flame speed of the biomass. Particle sizing is important. Fibrous biomass can be shred or chopped, but is generally resistant to pulverizing. Biomass should be kept separate from the coal.

Some blends are well known. Blends do not always behave according to the weighted average of the component fuels. Typically chemical properties change more radically than ash content or heating value. There can be capacity issues as lower heating value fuels are blended with coals. Longer flame lengths can be anticipated with biomass fired fuels. Blends can also impact efficiency, particularly for high moisture fuels. Deposition can be an issue for certain blends. Corrosion can be a concern when chlorides or alkalis are increased. Summary points include addition of biomass to coal is likely to increase the fuel flow, increase the flame length, and decrease the heating value of the fuel. Care needs to be taken to make sure the system can handle the fuel. Blending is becoming more common and will likely continue in the future. Blends will likely involve more low quality fuels. Each blend is unique. Blended fuels do not behave as the weighted average of the components.

XII. Potential Impacts of Alternate Fuels on Boiler Equipment - Carl Bozzuto, ALSTOM Power, Inc.

Carl Bozzuto of ALSTOM Power, Inc., pointed out that it all starts with the fuel. The better the fuel can be characterized, the better the chance of successfully utilizing alternative fuels with "conventional" equipment. Unit size and choice are dependent upon the fuel. These fuels are variable in nature and that variation has to be taken into account. There are a wide variety of stoker units and these can handle a wide variety of fuels. Fluid bed boilers can handle an even wider variety of fuels provided that the designer has up front knowledge of what fuels and fuel characteristics are anticipated.

The key factors for consideration are alkali content, chloride content, sulfur content, lead and zinc content, ash content, and moisture content. Alkalies tend to form low melting compounds. These compounds can cause sticky ash, slagging, and fouling. When some of these compounds are molten, corrosion is accelerated. Chlorides cause corrosion over the range of temperatures. The products of corrosion (iron chloride) are vaporous and thus not left behind. Corrosion is accelerated under deposits. Sulfur burns to form SO₂ and SO₂ is further oxidized to SO₃. Biomass is generally low in sulfur, but waste fuels and petcoke are often high in sulfur. The SO₃ can be a cause of low temperature corrosion due to the condensation of sulfuric acid. It also plays a role in the formation of ammonium bisulfate. SO₃ levels above 5 - 7 ppm tend to suppress mercury collection on activated carbon. At high temperature, the formation of pyrosulfates are very corrosive at metal temperatures in the range of 1200 - 1400 F. In the burner zone of low NO_x coal fired burners, there could be corrosion issues associated with recirculation zones bringing particles back to the wall under sub-stoichiometric conditions. Sulfidation can occur under these types of deposits. Lead and zinc can be found in certain waste fuel applications. These tend to form very low temperature melting compounds, particularly in the presence of sulfur and chloride compounds. Melting temperatures as low as 600 F have been measured. Rather rapid corrosion has been observed under these conditions.

Ash content is a matter of proper design and handling. When the ash content is increased, the heating value of the fuel is reduced. This necessitates feeding more fuel to meet the heat input requirement. The additional fuel brings in more ash. When the ash content of the fuel is doubled, the ash handling equipment needs to go up by a factor of 4. Moisture content also depresses the heating value of the fuel. Dried biomass has less than half the heating value of coal. To provide

the same heat input, twice the biomass must be fed. This means that twice the number of trucks will be required to deliver the fuel. Moisture in the fuel ends up as stack loss, as the water is basically vaporized in the furnace and pumped up the stack. The gas volume is also increased. Thus, adding a high moisture fuel requires a larger furnace volume, larger ducts, and more fan capacity.

Supply issues include the amount of alternative fuel available and the transportation of the fuel to the plant. Fuels that are high in moisture or high in ash (or both) are not generally economic to ship. This tends to limit the distance for which fuels can be transported. There could be incentives placed by regulations that might alter the economics. Never the less, it is costly to move material around. It typically costs on the order of \$5 - 10/ton to pick something up and put it down again. That is due to the fact that such actions use all proven equipment that is well down the learning curve. Bucket elevators, conveyors, and bins are all well established pieces of equipment. These are not likely to see drastic reductions in cost with increased utilization of alternative fuels.

XIII. Boiler Control Systems Panel - Denis Oravec, Automated Applications Inc, LLC, Moderator

The panel consisted of **Chris Henderson**, Automated Applications Inc, LLC; and **Robin Roberts**, Bambeck Systems.

Chris Henderson of Automated Applications Inc, LLC, reported on a project at the Abitibi-Bowater pulp mill at Thunder Bay, Ontario. The power boiler was a 900 psi unit making 500,000 lb.hr of steam. The fuels were bark and natural gas. The legacy method of operation was to base load the bark and use the natural gas for load swings. The goal of the project was to improve the handling of bark to increase the amount of bark burning and reduce the amount of natural gas. The fixed grate was converted to a stoker grate. The air capacity was increased. A vibratory system was added to improve fuel handling. Improved stability of operation and increased efficiency were particular goals. Reduced need for operator intervention was desired. Regulatory controls of the bark and gas were separated to allow for some optimization in performance. Lower oxygen levels were set to improve efficiency with automated air control based up oxygen sensing. Trending and demand information were developed so that the unit demand could be better predicted and used in a predictive control manner. A rule based, supervisory, advanced control system was installed using a priority constraint control strategy. Process equipment and operational constraints, as well as, environmental constraints were included in the system.

The key parameter was to develop steam at the lowest possible steam cost within environmental constraints. The system limitations (header pressure constraints, rates of change, time lags, etc.) need to be programmed into the system. Real time costs and measurements then can be used to control the system. This supervisory system sits on top of the traditional control system to guide the operation automatically. Gas constraints could be capacity, gas pressure, burner pressure, and min or max burner flow. Bark limitations are similar in terms of feed capacity, rate of change, and flow conditions. At this project, the payback was less than 1 year. The CO₂ emission was reduced 20% in the first year, 31% in the second year, and another 19% in the third year as more experience allowed the unit to utilize more bark compared to natural gas.

Robin Roberts of Bambeck Systems, reported on low excess air operation for boilers. Minimization of excess air lowers NO_x formation, SO₃ formation, and stack losses. The lower stack loss improves efficiency, which allows for lower fuel being fired. This reduces the amount of CO₂, as well as all other emission. Monitoring of CO is one way to determine if enough air is present. Too little air makes high CO. CO can be reduced with higher excess air at the expense of increased NO_x emissions and reduced efficiency. A control range of 50-150 ppm allows for reduced CO and reduced NO_x while generally improving overall efficiency. The system must start with complete combustion. A CO system is not a start up or shut down device. Once steady state is achieved, excess air is gradually reduced by closing the FD damper under controlled conditions. When the CO level reaches about 100 ppm, the system is put into trim mode to trim

the air requirement over above the existing air control system. A fast analyzer is needed to follow the CO in real time. An infra red detector is used in the stack. This "line of sight" analyzer across the stack automatically averages the concentration across the flue gas. The location should be closer to the ground to minimize the time delay. The system is designed to fail safe. Case studies included a refinery heater and a boiler application for biomass firing. A number of gas and oil fired refinery units have installed this system. The system has been available for 28 years. Most of the experience has been on oil and gas firing.

XIV. CO2 and Energy Efficiency - Peter Anderson, Environmental Resources Management

Peter pointed out the resource efficiency is a part of every day business. Process optimization and work practices continually seek to produce more products with less inputs and cost. Energy is a resource input for nearly every business. Electricity and steam use are common across all businesses. On the supply side, alternative sources of energy include cogen opportunities, renewables, and lower cost fossil fuels. Another option is to look at offsets or "green power" purchases. There are carbon markets for the purchase of various types of credits and allowances. As the CO2 reporting requirements come into reality, more and more people will become interested in your GHG emissions, including EPA, Congress, state and local regulatory agencies, NGOs, senior management, shareholders, and many others. Employees and students now have a heightened awareness of energy practices and carbon management.

The EPA reporting program includes named sources and a threshold of 25,000 tonne/yr. Depending upon assumptions, this translates into 25 - 30 MMBTU/hr. At issue, for publicly traded companies, will be the liability assigned to the potential cost of GHG emissions. A company that has 1 million tonnes/yr of GHG emissions that could be facing \$50/tonne allowance costs in the future could be forced to put a \$50 million/yr liability on their books for financial reporting purposes.