CIBO
Industrial Emissions Control Technology
Conference

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I. Trinity Compliance Workshop - Anthony Colella and Christi Wilson, Trinity Consultants

The Industrial Boiler MACT has been stayed. A revised schedule for a new proposal has been put out with a finalization in April 2012. Areas Source standards are subject to GACT, Generally Available Control Technology. The Area Source Rule has not been stayed. Units burning waste, as defined by the EPA Office of Solid Waste, are subject to the incinerator rules (CISWI). For the Boiler MACT rules, there are 5 HAP categories with 15 subcategories. The HAPs are CO, particulates, chlorides, mercury and dioxins. The subcategories include coal, oil, gas, and biomass with further breakdowns for certain types of technologies (PC, stoker, fluid bed, etc.). The MACT standards have been calculated by using the "best of the best" approach. MACT standards were defined as the average of the best 12% of units. When more than one HAP is being considered, the same units were not necessarily used. Thus, very few units can actually meet all 5 emissions levels at the same time, especially for new units. Biomass units have the most "livable" standards. At this time, it is unclear how the "re-proposal" will impact these standards.

For natural gas fired units, work practice standards have been proposed: A biennial tune up will be required. CO must be measured before and after the tune up. A hand held CO instrument may be used. There is a requirement for a "one time" energy assessment for all existing units. The assessment must be done by a "qualified energy assessor". The assessment is due within 3 years of the compliance date. Requirements include a listing of all energy consuming equipment and a listing of all potential energy saving measures. A work practice standard is required for start up and shutdowns. For malfunctions, the EPA has recommended the use of "affirmative defense" in the event of malfunctions to avoid civil penalties. The facility would have to prove that any excess emissions were beyond the reasonable control of the operator. Emissions monitors must remain in operation during the malfunction. This defense is only needed if a malfunction occurs and an exceedance occurs. If there is no exceedance, there is no need to report on the malfunction.

Emissions averaging is only allowed for particualtes, HCl, and mercury for existing sources in the same subcategory (ie all biomass stokers at the facility). Standard EPA testing methods are required. For CO levels, a continuous oxygen monitor is required. For units with an opacity limits, a continuous opacity monitor will be required. For coal, biomass, or heavy oil units over 250 MMBTU/hr a continuous particulate monitoring system is required. For units with wet scrubbers, operating limits will be established (ie pressure drops, flow rates, etc.). For dry scrubbers, similar operating limits will be established including bag leak detection systems.

Fuel records must be kept on a daily basis to document that no solid waste has been burned. Documentation of mercury and chloride levels in the fuel are also needed. For units with interruptible gas contracts, the curtailment hours must be documented in order to avoid being reclassified to a liquid fuel unit. For new units, the initial notification date was September 17, 2011. For Boiler MACT, this date has been assumed to be impacted by the stay. Compliance was due by April, 2014.

Limited-use boilers are those with less than 876 hours per year of operation. These do not have MACT limits. The rules will significantly affect all oil and not waste solid fuel fired boilers and process heaters. Compliance for natural gas units is fairly straight forward (ie tune ups), assuming that the environmental groups don't sue EPA for using work practice standards instead of emission limits. Nearly everything else will likely need modifications to meet the currently proposed limits.

The Area Source rules apply to those units that are not major sources (ie less than 10 ton/yr of any one HAP or less than 25 ton/yr of all HAP). Work practice standards have been proposed for most of these units. Start up and shut down periods must be minimized for existing or new units greater than 10 MMBTU/hr. Affirmative defense applies for malfunctions. Pollution control equipment must be operated in accordance with good control practices. Boilers with a CO limit must have a continuous oxygen monitor. Those with baghouses must have a bag leak detection system. Similar record keeping requirements are proposed. Existing coal units greater than 10 MMBTU/hr have mercury, CO, and PM limits. New biomass and oil units have PM limits. A one time energy assessment will be required for all units greater 10 MMBTU/hr. This requirement does not require an independent assessor, only a qualified assessor.

Non hazardous secondary materials that are not hazardous waste falls under the waste incineration rules. An incinerator is a unit that burns any solid waste. EPA sets emission standards for waste incinerators (CISWI) under Section 129. Boiler requirements come under Section 112. These are mutually exclusive. A unit can only be in one section or the other. A revised definition of what constitutes a fuel and what constitutes a solid waste has been issued.

The key issue is that the EPA has held to the concept of what has been discarded. If a material has been discarded in the first instance, it is considered a waste. Only if such a material has been "significantly processed' to convert the material to a fuel. Grinding or pulverizing alone is not considered "significant processing". There are legitimacy criteria that have to be satisfied as well. "Traditional fuels" are defined as not being solid wastes. Fuels that remain in the control of the generator are not considered wastes. Scrap tires that are under the control of a tire reclamation program are not considered wastes (ie tires collected from dealers, separated, and sold for fuel).

Waste coal units can go through a "formal" determination process to obtain a determination that the waste coal can be considered a fuel. Processing consists of steps to remove contaminants, improve the heating value, and increase the value of the material. Thus, an existing unit must first determine which MACT rule applies (Boiler MACT, CISWI, or Area Source MACT). For MACT units that require controls, emissions control equipment will be required. This will require knowing the current emissions levels at the unit. Many units will require continuous monitoring equipment. Staff and vendors need to be identified for both equipment and work practice standards. Planning will be critical in order to meet the compliance dates presuming that the 3 year requirements remain in place.

There are also new NAAQS requirements that have implications to industrial units and their permit requirements. Changes have been proposed or finalized for PM2.5, NOx, SO2, Ozone, and lead during the last year. These are having impacts on policy developments and permit activities around the country. Air dispersion modeling is now basically required for unit permits and state compliance plans. The ozone standard has been delayed. The PM2.5 standard was revised from 65 to 35 microgram per cubic meter on a 24 hour average basis. This standard includes filterable and condensable particulates. Revised annual standards are expected soon.

Background concentrations that are high tend to make modeling demonstrations very complex. Historically, most emissions data did not report the difference between filterable and condensable as well as the difference between PM10 and PM2.5. Modeling guidance is evolving. Final revisions to the SO2 NAAQS were issued in June, 2010. States are expected to perform modeling to determine attainment. In June 2011, states submitted recommendations to EPA. Attainment areas will be issued in June of 2012. The new 1 hour standard is more stringent. Units that met the old standard could be for PSD could show a NAAQS exceedance with the new standards.

Emission rates for new or modified units will be driven by modeling vs. BACT. Fire pumps and emergency generators are showing up in modeling exercises. Modeling realities may impact permitting for smaller, even non-PSD, increases. A nearby plant that is doing modeling for its permit may show that your plant is "causing" the model to show an exceedance. New ambient air monitors will be added by states for NO2 and SO2. This will likely result in new more severe non-attainments. It is now becoming easier (faster and less cost for permit) in non-attainment areas because LAER is required in any case and modeling is not. Therefore, the permit process is more straight forward.

On GHGs, the light duty vehicle rule issued last year has made CO2 (and GHGs) a regulated pollutant under the Clean Air Act. EPA has interpreted this trigger as requiring regulation under Title V and PSD regulatory programs. In addition, NSPS are being considered for GHGs. Under PSD, relatively low emissions levels would trigger nearly every combustion unit in the country to need a PSD permit. The Tailoring Rule was issued to alleviate this problem. This rule raised the emissions threshold for GHGs to 100,000 ton/yr (still relatively small units). PSD requirements after July 1, 2011 will require emissions calculations for CO2 equivalent emissions (ie all 6 GHGs). "Best Available Control Technology" is required for GHGs. Some kind of efficiency standard or work practice standard has been implemented thus far. No modeling has been required thus far (as there are no NAAQS for GHGs). Netting and synthetic minor calculations have been problematical for facilities that have not tracked GHGs in the past. Modifications that may increase GHG emissions of 75,000 tpy of CO2e will also trigger PSD requirements.

Minor sources for criteria pollutants may now become major sources when GHGs are considered. Title V also uses the 100,000 tpy CO2e threshold. The difference is that a unit can be a minor source for other pollutants but a Title V source for GHGs. When applying for a Title V permit, GHG emissions must be addressed. Synthetic limits can be established under a state NSR program, which would avoid the need for a Title V permit, if that is a requirement for the plant. GHG sources from the entire plant must be considered, even if the source is not under the Mandatory Reporting Rule (ie certain process emissions not from combustion sources). States are also having difficulties with their authority to regulate GHGs. Some states have SIPs that don't allow EPA or the state to regulate GHGs (the most prominent being Texas). The GHG reporting rule requirements were delayed to September from March because the reporting software was still under development. Facilities that are required to report should have registered with the web based reporting system.

II. **Stoker Compliance Workshop – Robert (Bob) Corbin, CIBO Consultant and Timothy (Tim) Loviska, Detroit Stoker Company**

Bob reviewed the database of 685 stoker units from EPA available to CIBO. Over half the units utilized biomass (about 51%) and the others burned a variety of solid fuels. The environmental control systems were also broken out. The slides will be available on the conference CD so that the exact numbers can be accessed. A stoker survey of the CIBO members was also carried out, as requested by the membership. Basic data on stokers such as year, fuel, control systems, etc. A total of 42 responses were received covering 61 boilers. If these 45 fire coal only. Some fire coal and TDF. Some fire coal, TDF, and wood chips. A small number of respondents burn biomass. Some 36 units control air with dampers, while 24 use fan controls. Only 7 units had scrubbers for SO2 control. The top reason, by far, for downtime still pertains to pressure parts (tube failures).

Bob solicited the audience for comments and suggestions for continuing the survey or, perhaps, a potential stoker conference or workshop. One question pertained to the requirements on coal supply and price. High grade stoker coal is reaching a price that is approaching current gas prices. One member noted that converting an existing stoker for their case cost almost as much as buying a small, gas fired package boiler. Detroit Stoker is offering stoker conversions with special gas burners to avoid pressure part modifications. Often the superheater needs to be replaced.

Tim covered some of the practices that can be used to optimize operations on a coal fired, stoker boiler. The Boiler MACT regulations offer a particular challenge to coal fired units, as well as the additional requirements that will be imposed for NOx and SO2 as a result of the new NAAQS standards. The majority of industrial units are spreader stokers, where the fuel is distributed over the grate. Fuel is thrown into the boiler where some burns in suspension and some burns on the grate. Smaller particles with low terminal velocities dry and devolatilize is suspension and never touch the grate. The larger particles need more time to burn and land on the grate where they burn out. The suspension part allows for more rapid load changes. The grate burning provides for stabilization.

A spreader stoker requires an even distribution of fuel and an even distribution of air. Departure from even distribution allows for air channeling, high unburned carbon, and potential clinker formation. Even distribution of coal requires proper operation of the coal feeder. A reciprocating coal feeder features a sliding plate that controls the amount of coal that enters the rotating blades that sling the coal into the boiler over the grate. Making sure the rotors and the plates are in good working condition is key to good operation. Worn plates and rotors contribute to variable coal flow rates. This is a particular problem when multiple feeders are involved. There is also a spill plate that directs the coal into the rotating device. These plates should also be adjusted to provide uniform feed from all of the feeders. An alternative to the reciprocating plate is a small conveyor belt that directs the fuel into the rotating feeder. These were developed to handle fuels with higher fines content (fuel particles less than1/4 inch).

Rotor speed also needs to be checked for proper speed setting. Rotor speed needs to match the dimensions of the boiler and the type of fuel. Underthrow feeders use counterclockwise rotation with an air assist in order to handle the fines. For the air system, there is undergrate air and overfire air. The objective is to minimize the total amount of air to the boiler while still maintaining good combustion and minimal emissions. A number of different levels of overfire air can be used. Older units used 80 - 85% under grate air. Newer units use 65 - 70% under grate air. This deeper staging provides for lower NOx emissions. Newer units have at least 3 levels of overfire air. Trial and error adjustments are typically needed in order to optimize the levels of NOx and CO. The lower nozzles are more effective for CO control. The upper nozzles are more effective for NOx control. The undergrate system should be adjusted for the correct level of excess air. A relatively high pressure drop across the grate assures a more uniform air flow through the grate. Seals are needed to avoid leakage through the grate shafts and up the wall. The seals need to be inspected to assure that they are in fact sealing. Roughly, every 1% of O2 represents 1% of boiler efficiency. Increased excess air increases NOx. Too little air increases CO. Tramp air contributes to excess air. This air enters the unit through locations such as ash hopper doors, front stoker doors, observation doors, stoker seals, and expansion joints. CO emissions are an indication of combustion efficiency. The control approach is to provide enough air at a high enough temperature to burn out the CO.

NOx results from both thermal formation and fuel bound nitrogen. High excess air contributes to higher NOx levels. High fuel nitrogen contributes to higher NOx levels. Higher fines contributes to higher NOx levels in stokers. Typical stoker emissions are CO at 0.15 - 0.25 lb/MMBTU and NOx at 0.5 - 0.55 lb/MMBTU. With staged air, the Nox levels can go to 0.45 lb/MMBTU. Adding flue gas recirculation can reduce the NOx to 0.30 - 0.35 lb/MMBTU. The VOC levels run at 0.05 - 0.10 lb/MMBTU. The unburned carbon loss ranges from 2 - 3%. The unburned carbon shows up mostly in the flyash. Flyash re-injection has been utilized to reduce carbon loss. The ash loading increases significantly as a result.

III. **Equipment Suppliers/Owners Forum – Norbert (Norb) Wright, Consultant, Facilitator See Review of Concurrent Forum Discuss**

Norb started the discussion by asking the question of whether or not the Boiler MACT levels can actually be guaranteed for new and existing units. The suppliers felt that the new units were problematical and that solid fuel new units would not likely be built (with the possible exception of biomass units). Particulates at 0.0011 lb/MMBTU can be difficult for particulate collection systems. There is little data available on dioxin/furans. Mercury is dependent upon the level of mercury in the fuel, which tends to be variable. CO is typically a trade off with NOx. Chlorides are a function of the chloride in the fuel. Further, the MACT rules apply over the entire load range. The "affirmative defense" for malfunction is not much of a defense since the burden of proof is on the owner/operator. The basic difficulty is that the risk of not meeting the standard falls on the owner. The supplier is not going to take risks that are beyond the supplier's control (ie owner's operations). The owner's control system is key to being able to make adjustments to the system (air flows, fuel flows, splits, fuel sizing, etc.). It is difficult to justify a new control system on efficiency benefits alone. Baseline data is another issue. In general, chlorides, mercury, and dioxin/furans have not been measured in the past. It is hard to establish what needs to be done without knowing the baseline. The baseline has to be done in accordance with the EPA methods. Since this baseline testing is costly, it tends to be put off.

One of the risks is getting to the point where utility compliance dates and industrial compliance dates overlap. It will then be more difficult to get qualified testing outfits and sufficient equipment suppliers to meet the compliance dates. The testing groups and permitting groups indicated that many owners are starting to look at getting this baseline data, but, in many cases, it is either incomplete or insufficient. Dioxin/furan is especially difficult because of the expense of doing the testing.

Stack data without boiler data and operating data is of limited value. Some owners are looking at additional value added parts of an upgrade (ie justifying replacing controls as part of an equipment upgrade). Suppliers would like to see the owners to start taking more action to prepare. Suppliers would also like to see more evaluation credit for high quality equipment, rather than price alone. Replacement bags come under pressure on price from some low quality, off shore, suppliers. Recommendations might include planning ahead, establishing baseline data, determining the value of efficiency, qualifying vendors, and establishing the basic goal of the project (ie just meet emissions, optimize performance, upfront cost vs long term costs, etc.). This gets back to the expected life of the equipment, the cost to repair and replace equipment, etc. It was also noted that some specifications are requiring the listing of all foreign supplied equipment and in some cases restricting supply from certain foreign regions. One question for the owners would be plans for switching to biomass or cofiring with biomass. The GHG rules for biomass have been delayed for 3 years. The Boiler MACT rules for biomass were less stringent, as proposed in the last round. There are also state requirements for a certain amount of renewable fuel use. This might prompt some units to switch or co-fire.

IV. **Review of Concurrent Forum Discussions – Frederick P. Fendt, The Dow Chemical Company, Moderator**

Pat Dennis of the Owner's Group reported on their session. The common themes from their group covering half the states. There is a significant difference amongst the several states. The availability and price of fuels is a big concern, both for coal and for gas. If units are forced away from coal, there is some concern about the capacity for the alternatives. There was also concern about disincentives for wood. There is a lot of concern about the timing for compliance with the proposed rules. Outage scheduling is one of the big concerns with the compliance requirements. Environmental regulations appear to be forcing non optimal solutions, both from an economic point of view and an economical point of view. CO regs on biomass are a concern where units do not have access to other fuels.

Carl Bozzuto, Ray Ganga, and Norb Wright reported for the Equipment Suppliers. They commented on 7 issues: planning ahead, establishing a baseline, the value of efficiency, establishing the real goal of the project, fuel switching, T's & C's/guarantees, and risk sharing.

The Government group was small at this point. Doug Straub of DOE reported for them. Their list included a question about controls for HCl and control for SO2 being used together. Another question was about AP-42 data being applicable over the long term. The representativeness of "single point" tests over the long term is an issue. Fuel cost and availability data are needed as well as long term operating data. One suggestion was to make the NOx and CO requirement into one regulation aiming at ozone compliance. One question from the owners was about heading toward a wider selection of fuels at reasonable prices, while the EPA is narrowing the choice of fuels. The price of gas is low right now, but it doesn't take much imagination to realize that there are higher prices for gas in other parts of the world and that someone will start exporting gas to Europe and Asia for the higher prices. One of the owners noted that there is no DOE program on stoker boilers for either improvements or environmental control technologies. There are universities that are looking to do experimental work and have stoker fired boilers, some of which are CIBO members.

V. Fundamentals of Combustion and Pollutant Formation - Carl Bozzuto

Carl reviewed the fundamentals of combustion including stoichiometry, excess air, mixing, temperature, and types of flames. Each of the major pollutants was reviewed including CO, NOx, SO2/SO3, Chlorides, Particulates, Mercury, and Dioxin/Furans.

VI. Environmental Rules, Regulations, and Implementation - Panel

The panel consisted of James (Jim) Eddinger, EPA; Marc Cone, State of Maine;, Andrew (Andy) Bodnarik, OTC; and Robert (Bob) Fraser, ERM. Jim Eddinger of EPA reported on the status of the reconsideration of the Industrial Boiler MACT.

Jim Eddinger reported a major source is one that is part of a facility that emits 10 ton/yr of any one HAP or 25 ton/yr of any mixture of HAPs, regardless of boiler size. Thus, a small, gas fired boiler in a facility that is a major source comes under the Boiler MACT rules. On May 18th the EPA delayed the effective date of the Boiler MACT and the CISWI rules pending reconsideration. The Area MACT rule was not stayed. The reconsideration was issued because of the significant changes in the rules between what was proposed in 2010 and what was finalized in February/March. The aim of the reconsideration was to allow for more time for public review and comment. Petitions for reconsideration were received from over 2 dozen organizations, including the Sierra Club. The Area Source rule received much less petitions.

A schedule has been proposed for issuance on Oct. 31, 2011 and finalization in April, 2012. Issues raised include the subcategories, monitoring, emission limits, MACT floor methodology, exemptions, compliance, tune-up provisions, energy assessment, output based standards, compliance date, fuel sampling, health based standards, and surrogates. No decisions have been made on which of these issues will be reconsidered. On the Area Source rule, the compliance schedule was one of the big issues as the tune up requirement was changed to March 2012. Seasonal boilers will have a problem with this date.

Subcategories, exemptions, detection levels, MACT floor methodology, monitoring, energy assessments, and surrogates were also commented on. If sources need help, the EPA regional offices are trying to help. Some additional information is available at http://www.epa.gpv/ttn/atw/boiler/boilerrpg.html. Most of this information is on the Area Source rules as this rule has not been stayed. DOE's Best Practices Steam Steering Committee is drafting a Boiler Tune-up Guide designed for two audiences – the boiler/facility owner and the technician doing the tune-up.

DOE is also working on formulas for calculating efficiency improvements and their associated emissions credits. Jim is the main contact for the Area Source rule. Brian Shrager is the contact for the Boiler MACT rule. The Office of Solid Waste is not reconsidering the definition of solid waste, but is planning to come out with some guidelines to help units figure out which rule they will be regulated under.

Marc Cone of the State of Maine noted that States had until May 2011 to revise their SIP's relative to the PM2.5 for PSD permits. Under the old rules, most of the Northeast was in attainment. There were more issues in the West due to forest fires. The new NAAQS for NO2 (100 ppb) required essentially immediate compliance. NESCAUM proposed a significant impact level of 10 microgram/m3. EPA has proposed 7.8, but indicated that another level can be used if justified. Modeling starts with assuming that 100% of the NOx is NO2. If that fails, the next level is to assume 80% of the NOx ends up as NO2. There is also an ozone limiting method. This assumes that at any given location, the amount of NO that converts to NO2 is proportional to the ambient ozone concentration.

The SO2 standard is a 1 hour standard of 75 ppb. The secondary standard is a 3 hour standard. Of the 249 monitored counties, 59 will likely not meet the 75 ppb standard. EPA will finalize the designations by 2013. Refined modeling will be required by June 2013. Non attainment areas are to show compliance by 2017. The standard will be difficult to meet. A small #2 oil fired boiler at a school (6 MMBTU/hr) showed violations with a typical short stack.

The ozone standard has been delayed. Once issued, there will be a 3 year period to designate, followed by another version of RACT guidance. The ambient CO standards do not appear to be a problem for boilers. The GHG Tailoring Rule will impact major modifications with 75,000 ton/yr increase in GHGs. Title V sources will need to address GHGs when renewing, revising, of applying for a PSD permit. EPA required 2010 GHG inventories in March 2011.

All 3 LNG projects in Maine are dead. There is a project to consider trucking Massachusetts LNG to Maine. The engine rules are impacting small sources as well. The HAP rules (part ZZZZ) applies to reciprocating internal combustion engines located at major and area HAP sources. There are some exemptions, including emergency generators. The definition of "emergency" is different in the 3 rules (diesel, spark ignition, and HAP). Maine filed reconsideration comments on the Boiler MACT rule. Issues included oxygen variability for wood fired boilers, support of health based standards, CO variability, compliance date, and solid waste definition. Maine has not taken delegation on the Area Source rule. They have sent notice to trade organization and are setting up some kind of technical support, yet to be defined.

Andy Bodnarik reported on the OTC activities. They work with states and sources to identify regional approaches to ozone transport issues. Gas delivered to electric consumers has increased over the last 10 years and is expected to increase in the future. Compressor stations along the pipeline system can be a source of both NOx and organics, both of which contribute to ozone formation. Vapor controls at gasoline stations are being considered. A white paper was developed on paint thinners and multipurpose solvents. A solvent degreaser model rule has been prepared. The OTC tries to estimate cost and effectiveness of various control technologies in considering proposed rules. There is an active stakeholder outreach program.

Bob Fraser reported on some of the questions that companies and facilities are asking in order to come into compliance with the new rules. Unfortunately, these rules are still is state of flux. This makes it difficult to determine what needs to be done in order meet the rules. The rules are also subject to litigation and appeals. In addition, next year is an election year, which will only serve to complicate the problem. As a result, we have a form of gridlock. Owners are reluctant to commit new funds without really knowing what the rule is. They are waiting for the rules to sort themselves out. In addition, agencies such as NESCAUM, OTC, and states continue to modify RACTs. The NAAQS are being reduced. Coal is being challenged on every project. There have been a few top down BACT GHG permit applications. The states have not seen this before and tend to push these back to the regional EPA. The regional EPA hasn't really seen these either and this makes for potential delays in any project that triggers PSD. Permit groups are recommending customers to try to avoid triggering PSD.

VII. Particulate and Multi-Emission Control Technologies - Panel

The panel consisted of Ryan Zupon, Sega; Rod Gravly, Tri-Mer; Brian Higgins, NalcoMobotec; Brad Donat, Norit Americas; Jim Fisher, Clyde Bergemann; Bob Taylor, GE Energy; David South, Amerex; Mike Brubaker, FMC; and Jerry VanDer Werff, NolTec.

Ron Zupon, Sega Inc. reported on co-firing of alternative fuels. The project in question was for the city of Columbia, MO. There are two coal fired stokers connected to a common header. One unit is 160 kpph and the other is 240 kpph. The city currently fires about 10% biomass on a heat input basis. The units have a common baghouse and a common stack. The types of biomass include raw, woody biomass, agricultural biomass, biomass waste products, and man-made solid biomass. Biomass tends to have higher moisture and lower heat content than coal. Woody biomass requires up to 7 times the volume of coal for the same heat input. This has a significant impact on fuel handling and transport. The maximum amount of co-firing was limited to 50% biomass for a number of reasons.

Woodchips were selected as the biomass fuel. Sawdust, wood pellets, and agricultural pellets were also considered. These fuels were considered as potentially available within a 100 mile radius. The cost varies proportionately with the distance. Seasonal impacts will continue to impact availability and price. Future competition for the fuel will also impact price.

Truck delivery brings the wood chips to the plant. A handling system costing about $1.2 million needed to be added to the plant. Current control system was not adequate for combustion optimization. Overfire air and SNCR was evaluated for CO control. Duct injection, SDA, and circulating FG scrubbers were considered for chloride control. Duct injection looked like the most cost effective system for $4.7 million. For mercury and dioxin/furan, activated carbon injection was considered. Combinations of treatments were evaluated.

Capital and O&M costs were evaluated. Overfire air for NOx control appeared to be the most cost effective. The PAC system was about $0.8 million. Both low and high sulfur coals were considered. High sulfur coal required a lot more capital in order to meet emissions requirements. On a total economic basis, it has a higher overall cost. The use of biomass to reduce sulfur and particulates does not appear to be more cost effective. The full coal case with duct injection appeared to be the most cost effective approach.

Rod Gravly, Tri-Mer Corporation reported on ceramic filters. Units up to 300,000 acfm in size are available. The equipment looks like a bag, but the fiber material is actually a ceramic fiber. They are a low density fibrous material with higher porosity. For particulate only, the filters can operate at up to 1650 F. They are capable of meeting 0.001 lb/MMBTU. The filters are arranged in a manner similar to a bag filter. As the gas passes through the filter material, a residual layer is built up on the surface. This layer does not get removed in cleaning. The particle layer is built up on top of the residual layer and does not penetrate the filter wall. The filter material does not penetrate the ceramic material. Typical filter life has been 4 - 5 years with some cases lasting to 10 - 15 years.

Applications have included aluminum powder, nickel refining, zirconia production, and smokeless fuel production. For SO2, HCl and acid gases, dry injection systems can be used. Both lime and sodium based sorbent systems can be used. The sodium systems get better capture. Temperature limits are in the range of 300 - 1200 F. NOx can be treated by embedding catalyst in the wall of the filter. With ammonia injection, the Nox can be reduced. The fact that the ash does not penetrate the filter, the catalyst sees a relatively clean gas and lasts a lot longer. The catalyst is actually attached to the fiber itself. It does not change the pressure drop characteristics of the filter, but does add 5 pounds to the filter. The NOx catalyst has a temperature limit of 700 F. Powdered activated carbon (PAC) can also be added to capture mercury and dioxins.

Brian Higgins, NalcoMobotec, reported on mercury solutions and duct injection systems for acid gases. For mercury capture, a bromine type oxidizer is added to the boiler to increase the fraction of oxidized mercury in the furnace. Then an activated carbon system is used to capture mercury. From 200 - 1000 ppm of the additive in the gas increases the oxidation from less than 90% to over 95%. The material can be added to the coal feed system. At one test unit at 580 Mw, the mercury emissions were being reduced to 1.0 lb/trillion BTU with about 5 lb of PAC/MMacf. With the addition of the oxidizer, the PAC could be reduced to 2 lb of PAC/MMacf. Injecting the PAC at a location upstream of the air heater improved to performance accordingly. With an optimization strategy, the cost of mercury removal went from 30 cents/Mwhr down to 7 cents/Mwhr with the additional benefit of being able to sell the ash. The total cost of the additive and the PAC was $360 K/yr.

For acid gas control, wet systems will capture SO2 and HCl. For those units without wet systems, a dry sorbent system can capture acid gases. The system needs to be compatible with particulate matter control. DSI for SO2 control and SO3 control has been done for the utility industry for some time. DSI for HCl is in the demonstration phase. The attractiveness of DSI is low capital cost and fast project schedule with minimal impact on the boiler. Injection location and mixing are very important. Particle size matters. Sorbent conditioning is an issue as some of these materials are hygroscopic (leading to inline pulverizing). Metering is also important. A number of trials are ongoing.

Brad Donat of Norit Americas, reported on dioxin/furan removal with activated carbon. There are 75 different dioxins and 135 different furans. The dioxin has two oxygens (hence dioxin). The formation temperature is in the range in 400 - 800 F. Activated carbon utilizes capillary condensation to bring the material into the pores of the carbon. Once condensed, the material tends to adhere to the walls of the pores. The adsorption improves at the lower temperatures as there is more condensation. A baghouse creates a mini fixed bed reactor and, thus, is about 3 times as efficient in collection. The particle size for the activated carbon has a d50 of 20 micron. Tests at two sites (one a municipal incinerator and one a medical incinerator) showed over 95% collection of dioxin/furans. European tests also were able to obtain over 95% removal. The lignite based activated carbon produces a carbon with the more appropriate pores (meso pores) for dioxin capture.

Jim Fisher of Clyde Bergemann, reported on HCl and SO2 mitigation in a biomass boiler. The plant is located at Evergreen Community Power in Reading, PA. The boiler is a CFB unit firing construction debris. Full load is 330 kpph of steam flow. The plant makes power for a neighboring production plant owned by a sister company. The pollution control devices are all located on the hot side of the air heater. The plant was built in 2008 and required Hcl limits of 0.48 lb/MMBTU and an SO2 limit of 0.35 lb/MMBTU.

The original trona injection system didn't really work. Testing was carried out at part load with very little SO2 present. Milling was shown to be effective in reducing sorbent usage. Injection locations included downstream of the multiclone, upstream of the multiclone, and upstream of the economizer. There is a lot of flue gas stratification coming out of the economizer. The economizer location was rejected due to potential ash buildup. The final injection location was upstream of the multiclone. A CFD model was created to model the flow. Flow traverse data showed that there was more gas flow in the injection location than the plant predicted. A new lance design was developed with and improved injection system reduced the amount of sorbent needed to meet performance requirements. An inline trona mill was used to reduce the particle size down to roughly 9 micron. With a tighter particle size distribution. For this plant, a normalized stoichiometric ratio of trona is required to meet acid gas permit levels. About 70 - 80% sulfur removal is required to meet a 98% or better HCl reduction. Ductwork issues and various plant vagaries will tend to make each plant different.

Bob Taylor of GE Energy, reported on a novel filter design for mercury capture. A test program at the Gulf Power MRC test facility (a 5 MW slip stream) was run to determine methods to reduce the amount of sorbent needed to capture mercury. A pleated filter bag was thought to improve the effective air to cloth ratio and reduce the frequency of cleaning cycles. The pleated filter was wrapped around a perforated core. The gas flow rate was varied between 14,000 to 19,000 acfm. Different cleaning intervals were tested. Flue gas temperatures at the bag inlet were varied as well as the quantity of inlet dust. The testing was carried out over a period of 10 days.

Pressure drop driven pulse cleaning at the lower flow rate with no PAC averaged 80% mercury capture. The inlet temperature was 343 F. At 280 F and not PAC with a 30 minute cycle time, the capture increased to 97%. However, there was not a clear relationship between pulse cleaning interval and mercury capture. Over a series of tests, capture ranged from 75% - over 90% without PAC addition. Previous testing without pleated bags was 35 - 45%. The reduced temperature impact was significant. The average inlet mercury inlet was 10 micrograms/m3 with 80% elemental and 20% oxidized. Checking the CEMs monitors with carbon traps indicated that the measurements were accurate.

In order to investigate the impact of flyash, the ESP was placed in service to remove particulates. The removal of the particulates by the ESP deprived the baghouse of particulates to form a filter cake that can be effective for removing mercury. The mercury can be oxidized by passing through the pleated filter with some flyash on the bags. HCl accumulation on the surface which can oxidize mercury to mercuric chloride. The geometry of the pleated element creates a non-uniform dust layer which is thick in the valleys and thin at the tips. The gas flow approaches the filter surface at an obtuse angle rather than a normal angle as would be the case in a typical filter. The ash is the effective sorbent. The carbon in the ash was very low. The bag material is a teflon/ryton blended material in the pleated element arrangement.

David South of Amerex, reported on the various technologies that can be used for MACT compliance. Dry scrubbing systems include the injection of carbon, lime, trona, and sodium bicarbonate. Membrane bags are used for completing the chemistry that starts in the ductwork. Semi dry scrubbing systems utilize a two fluid nozzle for high levels of SO2 control as well as high chloride control. For the baghouses, a tuned blow tube is used to get the same flow and pressure drop across all of the bags. About 24 DSI units in the US have been installed since 2005.

Jerry VanDerWerff of Nol-tec Systems, reported on dry sorbent injection for SO2, HCl, and Hg mitigation. Typical sorbents include trona, sodium bicarbonate, lime, and carbon. Sorbent suppliers do not guarantee performance. The equipment suppliers are the ones that make the system guarantees. The sodium based systems are good for SO2, SO3, and HCl. The lime systems can capture the SO3 and some of SO2, but has not been as effective for HCl capture. Lime suppliers are working on this capability. Storage silos need to be kept dry. Compressed air is used to promote flow at the discharge of the silo. Very dry air is used to keep the silo dry. Loss in weight continuous feeders are deployed. Dilute phase conveying is used to move the sorbent to the injection point. In line milling is used to generate the fine particle sizes. Injection lances are dependent on the size of the duct at the injection point. Bin vent filters are used to clean the fill vent gas. Small weigh hoppers are used for gravimetric feeding. Trona can be abrasive and "T" lines are recommended for directional changes. An inverted cone splitter allows for up to 6 - 1 splitting to feed the lances. There are portable systems for plant testing. These can be used to determine if dry sorbent injection can help meet plant requirements.

VIII. Fundamentals of Mercury and Criteria Pollutant Monitoring - Brian Conway, Sick Maihak, Inc.

Sick Maihak, Inc. has developed a continuous mercury emission monitor that has been certified in Germany. Maintenance on older analyzers had been particularly high. This has been a particular goal of the new analyzer. Depending upon the application, the new analyzer comes with a written guarantee for 3 months, and up to 6 months, of unattended operation. A standard probe for mercury is deployed along with a typical sample line system. An injector is used rather than a pump in order to eliminate equipment with moving parts. In the sample cell, all the mercury is converted to elemental mercury.

The cell operates at a very high temperature (1000 C). Again there are no moving parts is the cell device. An insulated double wall design uses a heated quartz element to obtain the required temperature. Replacement is recommended after two years. The cell contains all of the chemicals that it needs so that there is no need to add or replace fresh chemicals. An atomic absorption signal is used to narrow the spectrum that is being used. The cell makes use of the Zeeman effect to improve the specificity of the measurement. This is accomplished by putting a magnet around the source. The light signal is polarized and split to create a reference signal and a sample signal every 2 micro seconds. The cross sensitivity for SO2 (which overlaps mercury) is avoided by using the Zeeman effect since both the reference signal and the sample signal have the same SO2 concentration. A constant adjustment is made for zero by a patented adjustment system.

A mercuric chloride span gas is utilized for span and calibration. The mercuric chloride capsule needs to be replaced every 3 months. The cabinet is a stand alone device with air conditioning. The entire box weighs 550 lb. Field tests were performed at an incineration plant and a cement plant. The results were compared to an older analyzer that used a gold trap for mercury, which gave a signal every 3 minutes. The results tracked the older system very well. Both tests ran the new monitor unattended.

In the US, there are two existing types of systems. These systems require weekly maintenance (daily in some cases). Sample line lengths of 150 ft have been tested without sample loss. Measurement accuracy is at 0 - 1 microgram/m3 full span at plus or minus 1% in their latest submittal.

IX. Boiler MACT Compliance Requirements for Area and Major Sources – Anthony (Tony) Colella, Trinity Consultants, Inc.

While the Boiler MACT has been stayed, the Area Source GACT is still in effect. MACT standards are maximum achievable control technologies and represents the average of the best 12% of units. GACT is generally available control technologies. The MACT rule covers industrial boilers and process heaters. The GACT rule only applies to boilers. Existing units are those that commenced construction on or before June 4, 2010. This date has not changed. Any unit that burns any solid waste is considered a waste incinerator and is subject to the CISWI (commercial and industrial solid waste incinerator) rule. The CISWI rule has also been stayed.

A major source is a facility that emits 10 ton/yr of any HAP or 25 ton/yr of all HAPs from total operations at that facility. For the Industrial Boiler MACT, there are 5 pollutants, CO, particulates, chlorides, mercury, and dioxin/furans. Particulates, mercury, and chlorides are “fuel based” compounds. The CO and dioxin/furan are combustion based compounds. There are 15 subcategories that are based on the fuel burned and the type of combustion system for solid fuels. The key to figuring out which category is understanding the definitions of “designed to burn” in the rule. Thus, a unit that is designed to burn at least 10% biomass is designated a biomass boiler. A unit that is designed to burn at least 10% coal is a coal fired unit, unless the other co-fired fuel is biomass.

Emission limits apply to units greater than 10 million BTU/hr. Work practice standards apply to Gas1 units and small units. Tune ups are biennial for small units and annually for large units. A one time energy assessment is required for all existing units. Assessments must be done by a “qualified energy assessor”. The energy assessor can be a company employee. The assessment is due with the compliance date. The audit must include a list of potential energy savings measures. Start up and shut down issues are being handled by a work practice standard requires the unit to minimize emissions by minimizing the time for start up and shut down and by following the equipment manufacturers' start up and shut down procedures. Malfunctions are handled by "affirmative defense", which requires a minimization of emissions and a root cause analysis. The limits now apply to all operations except start up and shut down.

Emissions averaging can be applied to existing sources within the same subcategory for the fuel based compounds. Testing requirements include using standard EPA test methods. Monitoring requirements include a continuous oxygen monitor, a continuous opacity monitor (for those with opacity limits), a PM CEM for units over 250 MMBTU/hr, and monitors for certain operating limits established during performance testing. For limited use units, the operating hours must be monitored. For fabric filters, a bag leak detection system would be required. Record keeping requirements include all reports and data needed to establish that the unit has remained in compliance. These rules significantly affect all oil and non-waste solid fuel fired boilers. Compliance is straight forward for natural gas. All other units will likely require additional equipment to meet the limits (in theory at least 94% of all units).

An area source is anything that is not a major source. The regulated compounds are mercury, PM, and CO. There are 3 sub-categories of coal, biomass, and oil. Gas fired units are supposed to be exempt from the rule. For units above 10 MMBTU/hr, there are biennial tune ups, start up and shut down following OEM procedures, and a one time energy audit. Malfunctions are handled with affirmative defense. Fuel analysis can be used for mercury only if it is demonstrated that emissions would be under the compliance level. For GACT, initial notification is Sept. 17, 2011. The compliance date is March 2014.

X. Stack Testing, Monitoring, and Controls for Boiler MACT - Panel

The panel consisted of **Dan Todd, Air Quality Services**; **David Ozawa of Mostardi Platt**; and **Bob Davis, Airgas**. **Dan Todd of Air Quality Services**, pointed out that monitoring has been required by the 1990 modifications to the Clean Air Act. The concept for monitoring gases is to pull a sample from the gas stream and subsequently analyze it. The location of sampling is important. Direct extractive systems are typically simpler, but are subject to corrosion and interference. Dilution extraction systems use clean, dry air to dilute the gas so that the mixture is below the dew point. This requires a source of dry air. It no longer can measure oxygen and the sample dilution raises the lower limit.

Opacity monitors have been available for a long time. Attenuation of a light beam is related to an opacity level. PM CEMs are relatively new. There are two methodologies: light scattering and beta guage. A data handling system will be needed. EPA has requirements for these systems. System location is a consideration. Tie in to the operating system is a question. Report generation should be given careful thought. On the O&M side, who will handle the system and how often needs to be decided. There are also QA/QC needs for the system. These systems will likely cost more than what was planned for. Stack testing is generally done for specific tests. Particulate sampling for MACT does not require condensable fraction measurement or PM2.5. However, many states are asking for condensables and PM2.5.

For filterables, EPA Method 5 is the standard reference method. Isokinetic sampling is typically required for EPA methods. Method 202 is used to measure condensables. Hcl testing is covered by Method 26 and Dioxin Furams (D/F) are covered under Method 23. Although these methods are variations on Method 5, the D/F levels are so low that a separate train will be needed for Method 23. This also means longer runs, lab measurements, and increased QA/QC. All of these tests require a velocity travers in order to establish the gas flow rate. There is a moisture determination as well. Thus, time, energy, and budget must be estimated and allowed for to do a stack test.

It is recommended to get help on these. There are 88 separate, source specific subparts to the NSPS and 133 subparts to the NESHAP. Nobody can understand all of these.

Dave Ozawa of Mostardi Platt Environmental reviewed particulate testing method issues. Particulate test methods used to be relatively simple. A sample was collected, weighed, and related to the gas flow. However, as the emissions limits have been reduced and the results being used as a surrogate for heavy metals. In paired testing, the high purity filters have shown less particulates than the standard borosilcate glass filters. It is anticipated that the acid gases are being "captured" on the borosilicate glass (which is alkaline). Substituting quartz filters for borosilicated filers can be one solution to this problem.

Bob Davis of Airgas reported on the protocol gas verification program. There has not been an update in 14 years. There is a requirement for all part 75 units to use calibration gases supported by the EPA program. Blind testing is used to verify that the calibration gas is accurate. A sample cylinder is sent to NIST and tested. NIST does the analysis and bills the vendor. The results are posted on a web site. The accuracy has to be within 2%. Each vendor has a PGVP number by location.

The new rule was promulgated in March. There are new requirements for gas vendors and for stack testers. The National Institute of Standards and Technology (NIST) has standards for gas reference materials in order to be traceable in parts per million (ppm). There is a new standard for research gases. The traceable gas cylinder is the only way to verify readings in gas analyzers.

Ammonia is a new EPA protocol gas. N_2O is a new protocol gas. HCl and zero gas are being developed. The problem for HCl is in providing a gas that is stable for at least one year. Several foreign countries have zero gases, but not the US. A NIST standard is being proposed with pollutant levels guaranteed to be under 100 ppb. The certification date is the date on the bottle plus one day (so the bottle can be used on the day of cert expiration). There will be longer shelf lives for oxygen, CO_2, and propane (up to 5 years).

Qualified individuals are required for part 75 testing (QSTI). The price on zero gas is likely to increase. The price per cylinder will likely increase by $2. With longer shelf lives, overall cylinder costs should go down. Make sure that the supplier has a cylinder gas management system.

XI. Sorbent Considerations for ICI Boilers - Panel

The panel consisted of **Paul Jones, Solvay Chemicals Inc.**; **Melissa Sewell, Lhoist North America**; and **Robert Huston, ADA**. **Paul Jones of Solvey Chemicals Inc**. reported on HCl and SO2 mitigation with dry sodium injection. The HCl limit is 0.035 lb/MMBTU for coal and biomass units. Injection locations can be at most likely locations above 275 F (ie before the particulate collection, before the air heater, or before the economizer). Dry injection systems are lower in capital cost that most other systems. The sodium products are typically safe and easy to use. The EPS efficiency can improve. A mercury capture system using PAC can also improve the mercury capture as the sorbent captures SO3, which competes for active sites on the activated carbon.

Trona is a natural mineral that is mined. Sodium bicarbonate is manufactured from sodium carbonate. When heated both of these substances release water and CO2 and increase the surface area of the remaining sodium carbonate. The increased surface area provides faster reaction rates. At a 400 kpph, coal fired unit, a test matrix was used to evaluate the relationship between HCl absorption and SO2 absorption. At high absorption rates for HCl, additional SO2 absorption was obtained.

At a 100 Mw utility unit, 98% Hcl reduction was achieved. In spite of the additional solids added to the gas stream, the ESP performance improved to the point where the outlet particulate rate was lower with the trona addition. Milling of the sorbent improves the performance of the material. Dispersion and mixing with the gas is critical. Trona runs about $250/ton, while sodium bicarbonate runs about $280/ton, both dependent upon freight costs.

Melissa Sewell of Lhoist North America reported on the use of calcium for dry sorbent injection. Hydrated lime can be used for sorbent in a DSI system. In the 80s, the DOE/EPA LIMB (limestone injection multi burner) project used a conventional hydrated lime for SO2 removal. SO2 capture in the range of 50 - 60% was achieved. As NSPS required over 90% removal, the system languished. In the early 2000's, SO3 control was recognized as needed for either condensable, PM2.5, and/or SCR oxidation control. Hydrated lime injection has been used for SO3 control. Other acid gases can also be removed.

Factors impacting performance include temperature, flue gas moisture, other gases, reagent reactivity, reagent surface area, injection location, and mixing. At lower temperatures, good SO3 and Hcl capture can be achieve, while SO2 capture is low. As the temperature increases, SO3 and HCl capture falls off and SO2 capture increases. Hydrated lime can be enhanced to increase the pore volume and surface area of the particles. Surface areas have improved from 10m2/gram up to 40 m2/gram. Ca/Cl ratios in the range of 1.5 - 2.0 are needed for high levels of removal. There is limited data on HCl removal on coal fired plants and demonstration is needed.

A pilot scale test at Southern Research Institute evaluated the 20 m2/gram and 40 m2/gram hydrates. HCl removals are better at lower temperatures (after the air heater). At 1.5 lb hydrate/lb gas, HCL reductions in the 92 - 98% range were achieved. Better reductions at lower injection rates were achieved when a baghouse was used for particulate collection for the same

HCl capture rate, especially at the lower injection rates. Standard hydrated lime runs about \$100/ton and the enhanced hydrated lime is about \$175/ton without transportation.

Robert Huston of ADA reported on powdered activated carbon (PAC) injection. Activated carbon is made by driving out the volatile matter of a carbonaceous material that is somewhat amorphous that combines graphitic layers and cyclic rings. This creates a lot of pores in the carbon. There are a number of other elements carried with the carbon including iron, sulfur, nitrogen, etc. Granular activated carbon is generally better for liquid applications. PAC is generally better for gaseous applications. There are 3 key features of the activated carbon: surface, pores, and particles. The surface provides host sites for various chemicals and chemical functionalities.

Pores provide holes for transport the captured material to the interior of the particle. The particles themselves provide for contact with the gas to be cleaned. Pore sizes vary from macro pores, meso pores, and micro pores. The size between 20 A and 500 A represents the meso pores. The particle provides the overall transport mechanism to be injected into the gas, capture the material, and then be removed from the gas. Mercury exists as elemental mercury, oxidized mercury in the gas, and mercury bound to the ash as particulate. Halogens accelerate the oxidation of mercury. Certain metals act as catalysts for oxidation.

In the case of activated carbon, included metals and moisture in the pores helps to oxidize the mercury. Ultimately, the mercuric chloride or mercuric bromide is adsorbed by the activated carbon in the meso pores. Dioxins and furans can also be captured on activated carbon. These compounds can be destroyed in the furnace with sufficient residence time. At lower temperatures (400 - 600 F), these compounds can reform if the constituents are available. Moving through this temperature range quickly can reduce the re-formation. These materials will occupy the meso pores in activated carbon. Lignite based activated carbons have a higher percentage of meso pores. The problem is that the proposed limits of 0.004 nanograms/m3 for existing units and 0.003 nanograms/m3 for new units are so low as to be difficult to detect. EPA Method 26 has a detection limit of 0.01 nanogram/m3. Activated carbon runs from \$0.85 - 1.00/lb FOB. Typical dosage rates are 2 lb/MMacf with a range of 0.5 to as much as 6 lb/MMacf.

In the follow on question and discussion session, one of the questions related to the combined use of the injection of alkaline substances for HCl control and PAC for mercury control and any interactions. Trona injection will remove SO3, which will help activated carbon. However, chlorides promote mercury oxidation. Removal of HCl will reduce the level of mercury oxidation and work against mercury capture. NOx is also absorbed on activated carbon. Units without NOx controls can also interfere with activated carbon. Brominated PAC can overcome the lack of chlorides. Injecting the alkaline material at a higher temperature helps the chloride removal. Injecting the PAC at lower temperatures improves the mercury removal. This is another strategy that can be used when both systems are deployed on the same unit.

XII. Work Practice Standards for Boiler MACT Panel

The panel consisted of Norb Wright, Energy Consultant; Daryl Whitt, TRC; Florian Wisinski, CleaverBrooks; Chris Henderson, AAI-JMP; and Peter Rugg, MacArthur Energy

Norb Wright, Energy Consultant talked about tune up issues. One of the problems with older boilers is that the supplier may be out of business. Certainly the technology may no longer be representative. Testing should be done at one location. Having one group test in the boiler and one group test in the stack will likely end in different results.

Calibration of all instruments, gases, monitors, etc. is critical. Establishing the performance before changes is important. Documentation is key to being able to show that any testing and improvements were made. Photographic documentation is recommended, both before and after tuning. Evaluating flame impingement tends to be somewhat subjective and requires experience. Inspecting the control system involves not only the hardware and linkages, but also the software and instrumentation. Re-tuning the boiler to optimize CO emissions needs to consider the other requirements of the operating permit. There is a real world trade off between CO and NOx emissions. There is a trade off between efficiency and CO emissions.

Start at full load and adjust the combustion gradually by reducing excess air and watching the CO, O2, FGR (if used), and NOx levels to maintain stable flames. The final oxygen level should be selected with an appropriate margin considering the mode of operation, operator experience, and safety. The process can be repeated, moving down at equal increments until minimum load is achieved. The data can then be entered into the control system after being checked. A report will be required and should be reviewed before the tuner leaves the site. Good documentation is essential.

The whole process needs to be planned out ahead of time. There are always operational issues. Units that are used mostly for heating will not need full load in the spring. If the unit is to be tested at full load, there needs to be a means to exhaust the steam. Hot water boilers have a particular problem in this respect. The tune up will require a more detailed test program than normal. It is likely that a shut down will be needed to inspect burners, dampers, fans, duct work, linkages, etc. Planning is essential.

Documentation is critical, as the agency will require proof that a tune up was done. Plant loads need to be considered so that there is a minimal impact on operations. It is likely that there will be at least one or two days when the unit is down for inspection. The tuning operation is at least a day. If anything needs to be fixed, that will have to be done and the unit retested. It would be recommended to tune up the unit before any stack testing. If possible, portable measurements should be made for the key criteria pollutants so that there is an indication of whether or not the unit needs to make any modifications to meet the limits.

Daryl Whitt of TRC reported on the Energy Assessment Protocol Development for the Boiler MACT. The goal is to look at energy efficiency at the plant. The requirement is a “beyond the floor” issue (ie no standard). It is a one time assessment. For the MACT rules, it covers the boiler and the facility. It is intended to identify “cost effective” energy conservation measures. The DOE has conducted energy assessments and typically finds that fuel/energy use can be reduced by 10 - 15% by using “best practices”.

The focus is on the major energy using systems and the energy management practices. The energy savings potential and payback period is to be identified (2 year payback target). The assessment must be conducted by a “qualified assessor”. For Area Source units, all units over 10 MMBTU/hr must conduct an assessment. The operating characteristics of the facility with specifications, O&M procedures, and unusual operating constraints should be evaluated. Establishing baseline performance provides a guide to the operator for any spikes.

An inventory of energy consuming systems is required. The assessor will make recommendations for improvements. A list of energy conservation measures must be made with a quantification of the benefits. The level of assessment is dependent on the energy use in a year. Smaller facilities can use a one day assessment covering at least 50% of the output. A middle sized facility can use a 3 day assessment covering at least one third of the energy output including the boiler and energy use system. Larger facilities will require more complete assessments. Energy use systems include process heating, air compression machine drives, process cooling, HVAC, hot water system, and process requirements. Cost effective measures have a 2 year payback or better.

Energy management practices cover the practices and procedures designed to manage energy. An energy manager with appropriate procedures and performance requirements must be identified. To meet Energy Star requirements, performance must be assessed and goals set. Action plans are created, implemented, and evaluated. Achievements are recognized. ISO 500001 standards can also be used.

The qualified energy assessor must have demonstrated capabilities in boiler combustion management, boiler thermal energy recovery, boiler blow down, energy purchasing, O&M practices, improvement opportunities, heating system opportunities, cogeneration, and steam end use. A comprehensive report is required, along with a signed certification that the assessment was completed. More information on qualified assessors and programs can be obtained on the DOE Save Energy Now web site.

Florian Wisinski of Cleaver Brooks Inc. reported on advances in combustion and boiler design in fire tube boilers. The objectives for improvements include lower emissions, improved efficiency, size, and boiler life. Older units had a rather high requirement for heat transfer surface per unit of output. With use of modern computer techniques (finite element analysis, material properties, CFD, etc.), the amount of surface could be reduced. Some 30 - 40% of the heat transfer occurs in the fire tubes. Plain tubes are not ideal for heat transfer surface. Internal surface modifications can significantly increase the heat transfer significantly. By reducing the total amount of surface, the volumetric heat release can be reduced in order to reduce NOx emission levels. Lower pressure drops can be achieved to reduce fan horsepower. Evaluation of the key thermal gradients and stress points allowed for better prediction of fatigue life. The new design has low NOx emissions (5 ppm), lower CO emissions, improved efficiency, smaller footprint (15% less), and longer life.

Chris Henderson of AAI/JMP Engineering reported on stoichiometric modeling and stage combustion strategies for stoker boilers. A current project involves re-control of 3 existing stoker units. These units change load frequently. Thus, trying to control these systems and meet the standards over the entire load range is exceptionally complex. These units were built in 1952. They were uprated in 1982. The units needed to reduce NOx and CO. In 2009, additional overfire air OFA headers were added and the gas recirculation system was improved (FGR). The initial control scheme recommended individual controllers operating from pressure curves.

Thinking about optimizing the air control, it was first required to decide where the air flow would be measured and controlled. It was decided to maintain the ratio of OFA and air to the grate throughout the load range. At different load points, different OFA headers were activated to maintain NOx control. A series of load curves and performance were generated to control the system. The algorithm was to start with the lower OFA headers and then adding from the bottom up. The undergrate air was set to move slower so as to avoid spikes on the grate. With the OFA, header pressures of less than 5 inches did not provide sufficient penetration to be effective in the furnace. This caused fluctuations in the boiler output and CO spikes.

In order to solve this problem, stoichiometric modeling was used to calculate the required quantity of air. A total air flow control was applied which used the OFA control for total air flow. The lb of air needed to release a given amount of heat from a hydrocarbon fuel is 755 lb air/MMBTU. The O2 set point is used to dynamically adjust the base air requirement for the unit. Tramp air presents a problem as tramp air and FGR contribute to excess O2 levels. The leakages into the boiler can be considered as air moving through a fixed orifice. If the furnace pressure is quadrupled, the amount of tramp air is doubled. If the oxygen increase is measured in this test, it represents doubling the tramp air and the resulting tramp air can be calculated. This allowed the tramp air to be accounted for in the oxygen measurement. Thus, the two main points of control are the desired amount of excess air and the ratio of under grate to over fire air.

A staging plan was developed that designated the header as being either in service or out of service. Headers that were out of service were on minimum cooling flow at 0.5 inches pressure. Headers that were in service were maintained with a minimum pressure of 5 inches to provide air penetration. When the highest header is in service it stays there. If more air is needed, another header is brought into service. At that time, there is a spike in oxygen that the control system adjusts. The control system will use whatever headers that are available (ie in service) to provide the amount of air required. The units now run in a much more stable condition and spikes have been greatly reduced. At this point, the units need to be tuned to optimize the splits and minimize the emissions.

Peter Rugg of MacArthur Energy reported on engineered compliance fuels. Solid fuels contain ash, moisture, mercury, chlorides, sulfur, and other materials. When this material goes into the boiler, it must come out somewhere. If these materials can be removed prior to combustion, the fuel can be made much more uniform while reducing the potential for emissions. To the extent that some of these materials can be removed from the fuel, the efficiency of the boiler system improves. Great Rivers Energy uses flue gas energy to remove moisture from their lignite. It is possible to use density differences to remove some of the heavier materials to reduce the burden on the back end.

The target is solid fuel boilers. The goal is engineered coal fuels. The idea is to reduce the moisture, mercury, and chlorine in the fuel and possibly add biomass to the fuel. If possible, the goal is to meet compliance on mercury and chlorine and to minimize any dioxin/furan formation. The highest cost is in removing moisture. The cost of removing mercury and chlorine is 1 lb of coal in 1 ton of coal. For an Illinois coal, the heating value was improved 14% by drying the coal from 12% to 0.1%. The chlorine and mercury were reduced to well below compliance levels. The coal cost increased 3%. The capital investment was less than for additional back end equipment. Fuel prep does not trigger NSR. At a lignite unit, the moisture was reduced from 32% to 21% to improved the heating value. The mercury was reduced from .22 ppm down to .147 ppm, which allowed compliance. The coal cost increased by 8%. Cost savings on the operating costs for the unit were 1.5%.

For a 100 Mw unit with PRB, biomass was added. The heating value was improved. The CO_2 was reduced 10%. The algae plant required 140 acres. Nutrients from local farmers and CO_2 from the plant was used to grow the algae. For fuels that have dust issues, the resulting fuel can be briquetted for transport. With the potential for adding biomass, renewable fuel standards can be attained as well. The process involves a rotary kiln that provides a gentle pyrolysis (200 C) that removes moisture, chlorine, and mercury as a vapor. The process operates below the point at which organic volatile matter is driven off.

XIII. Strategic Energy/Environmental Management Panel

The panel consisted of **Laura Girard, Burns & McDonnell**; **Greg Raetz, HDR Engineering**; and **Mike King, Black & Veatch**.

Laura Girard of Burns & McDonnell reported on Energy Management and Energy Management programs. Boiler MACT and Area Source units require a one time Energy Assessment. The energy use system includes process heating, compressed air, machine drives, process cooling, HVAC, process heating, steam use, and controls. The energy management process is modeled after the Energy Star program. The Energy Star matrix is recommended, but not required. The process starts with making a commitment and setting up a team. The second step entails performance. Data is gathered and tracked. A baseline is established. Consumption is benchmarked. Energy intensity targets are identified. The data is analyzed and evaluated. Energy use, patterns, and trends are established. Technical assessments and audits are set up.

A typical energy assessment includes a review of utility data, baseline, and plans. Benchmarking of energy use to establish best practices is carried out. Site visits and equipment inventories are carried out. Energy conservation measures are identified. A measurement and verification plan should be established. The next steps are to set goals and create action plans to achieve those goals. Implementation of the plans follows, including evaluation of progress. The intent is to have a continuous improvement process.

In the case of an office building, the annual BTU/sq ft. was selected as the benchmark. Over the past several years, the head office building reduced their energy usage each year. As part of the program, recognition of achievement should be included in order to reinforce success. There are other energy programs besides Energy Star including, ANSI, ISO 50001, Save Energy Now, and others.

Greg Raetz of HDR Engineering, Inc. reported on a case study at American Crystal Sugar Co. on MACT compliance. Some of the issues included moving compliance targets, economic concerns, lead time for implementation, and competition for available resources. Sugar beet refining is a campaign based production process. Refinement and crystallization processes require significant amounts of energy. Steam from coal fired stoker boilers provides the heat source. There is a total of 11 stoker boilers burning coal with the oldest from 1948 and the newest in 1985.

The onset of the new NAAQS standards and the proposed Boiler MACT led to concerns about operation of these plants. With 5 facilities and 11 boilers that would likely need to be modified in 3 - 4 years, advanced planning was deemed necessary. Current conditions were measured to determine the existing status. Starting with CO, there are 7 units that would not make the standard. Similarly, 9 of the units would not likely meet the proposed dioxin/furan standards. The oldest units did not have much in the way of combustion controls that would be desirable to make air adjustments to optimize combustion.

With the age of the units, design data was often not available and control systems were out of date. With the range of boilers, there were a number of air in-leakage issues. For the most part, mercury levels were below limits, but the fuel inconsistency was not sufficient to be used for compliance. This requires stack testing and perhaps equipment. On particulates, again, only one unit looked to be out of compliance. However, most data logging is done manually. It is also not clear how modifications to other parts of the system will impact the ESPs.

The new NAAQS will cut existing state standards by a factor of 10. Preliminary modeling would indicate that the facilities would be in compliance if all margins were eliminated. Any flexibility would likely push a facility into the need for controls. The modeling was not a straight forward exercise. In planning, a worst case scenario is being prepared for potential necessary modifications. The idea is to prepare packages that can quickly turn into specifications so that the various approvals can be obtained in a timely manner. Based on the initial evaluation, some level of modification would likely be required at all facilities.

Combustion modifications are being considered first. From initial evaluation to development of conceptual designs will take 1.5 years. Preliminary order of magnitude costs are in the range of $4 - 9 million, although any complete replacements will be much higher. This will be a stretch to get everything done by April 2015. Permit approvals is a big unknown. It does look line one of the facilities may be able to meet all of the limits. The fuel is low in chlorine, so that has not been a problem. Other proposed rules may add to the problem or increase the demand for available resources.

Mike King of Black & Veatch reported on activities at utility companies on energy management. Surveys have been done since 2006 in the industry. Major issues include aging infrastructure, reliability, regulation, and technology. Energy prices, carbon pricing, and energy demand are key issues. Growth rate in the industry has not improved. Load demand is projected at 1.0 - 1.5%. Water management, energy storage, and retrofit scrubbers were technology concerns. Discharge issues drive some of these concerns. On the question of the future of coal, over 80% felt that coal had a future once people realized the costs of the alternatives. Nuclear technology dropped down from recent years. Renewables were still considered to be too costly. Gas prices were felt to be steady at least for a few more years. The "fracking" issue was not considered to be major impediment. The water return from fracking is mostly a brine, as the water dissolves salts from the field. Transporting this brackish water and treating it will be the major expense, but it is not new technology. Retirements were estimated at 64 Gw, mostly in the Southeast and Midwest. Coal is estimated to drop to 25% of generation in 2035 while gas is expected to jump up to 42%. Gas pricing from a Deloitte study for 3 scenarios was $9/MMBTU in 2035 for the highest level and $6.50/MMBTU for the lowest with $8/MMBTU as the reference case with 1.9% US growth for gas. The strategic study is available at www.bv.com/electricutilitytrends.