CIBO Industrial Emissions Control Technology V Conference
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I. Emissions Compliance Workshop - Mike Remsberg, Trinity Consultants, Inc.

Mike provided an overview of the Boiler MACT situation, NSR Reform, Regional Haze, CAIR, and Greenhouse Gases. Many of these are changing fairly quickly, as court cases and regulatory suits as well as state actions impact the status and content of the rules. The Industrial Boiler MACT was proposed under 40CFR Part 63, subpart DDDDD in January 2003. The rule was published in the Federal Register on September 13, 2004, implying a compliance date of September 13, 2007. EPA is required to set MACT for new and existing major sources of hazardous air pollutants (HAPs). A site is a major source of HAPs is one that produces 10 ton/yr of any one HAP or 25 ton/yr of any combination of HAPs. Note that the site is considered the source rather than an individual boiler.

Included in the MACT are general requirements, emissions standards limitations, testing requirements, monitoring requirements, and record keeping/reporting requirements. The regulations contain specific definitions of boilers and process heaters. A new unit is one that commenced construction after January 13, 2003. A reconstructed unit is one that meets the reconstruction criteria and commenced reconstruction after 1/1/2003. An existing unit is not new or reconstructed. Temporary boilers are not covered by this MACT. Units that are exempt include hot water heaters, refining kettles, ethylene cracking furnaces, blast furnace stoves, and boilers used exclusively for R&D. Municipal waste combustors, hospital/medical waste combustors, hazardous waste boilers, solid waste incinerators, and utility boilers are covered under separate MACT rules. The regulated HAPs are particulate matter as a surrogate for metal HAPs, HCl as a surrogate for inorganic HAPs, CO as a surrogate for organic HAPs, and mercury. For PM there is an alternate of Total Selected Metals as a surrogate for metal HAPs. There are 3 sub categories including new/reconstructed units, existing large units; and small, units; and limited use solid fuel units: for solid, liquid, or gaseous fuels. There are no emission standards for existing small solid fuel units, existing liquid fuel units, existing gaseous fuel unites and firetube units are considered small units.

Compliance alternatives include economic compliance and technical compliance. Economic compliance includes switching to compliance fuel or modifying plant operations to meet requirements. Technical compliance includes equipment upgrades or new equipment installation (i.e. pollution control equipment). Compliance methodologies include performance testing, operating parameters monitoring, or fuel analysis. Performance testing requires an initial performance test, a fuel analysis for each type of fuel burned, operating limits, and COMS/CMS performance evaluations. An existing source must conduct the performance test within 180 days after the rule compliance date. The unit must retest annually for the first 3 years. Testing is then extended to every 3 years after the first 3 years. The results of all tests must be reported within 60 days. A site specific test plan and a site specific monitoring plan must be established.

The site specific monitoring plan requires performance evaluation results for each continuous monitoring system (CMS) and each continuous opacity monitoring system (COMS) ahead of the performance test. The performance test must be conducted at the maximum normal operating load while burning the type of fuel or mixture of fuels that contain the highest content of chlorine, mercury, and total selected metals.

More than one test may be required for different worst case fuels. For each fuel, 3 one hour tests are needed. The test must demonstrate compliance with emissions limits. Operating limits are then based on the test runs. This last feature is critical as operating limits include temperatures, flows, etc. that may not apply to "normal" operations. Fuel type means a category of fuels that share a common name or classification (i.e. bituminous coal, lignite, anthracite, biomass, etc.). Test protocols are established in 40 CFR Part 60.

Operating limits are specific to pollutant and control device. Maximum and minimum values for parameters at the highest emissions levels demonstrating compliance form the basis for the limits. These must be monitored to assure compliance. Operating outside of these limits constitutes a deviation. Thus a wet scrubber for particulate matter would require maintaining a minimum liquid flow rate and pressure drop established during the performance test to meet emissions. These parameters now constitute the continuous monitoring system and fall under the requirements for maintenance and calibration of monitoring systems (i.e. 2% sensitivity and semiannual calibration). Opacity monitoring must follow PS1 of 40 CFR 60 Appendix B. There are standards for pressure measurement, pH, voltage, belt feeders, etc.

Solid Fuel Compliance Alternatives include emissions averaging across existing large units, Health Based Compliance Alternatives (HBCA), and fuel analysis for HCL, total select metals, for PM. A fuel analysis option allows the demonstration of compliance with a fuel analysis plan that results in a calculated emission that meets the compliance rates. The site specific fuel analysis plan must be submitted 60 days prior to testing. Some states are trying to impose operating limits under the plan submission. The operating requirements are to maintain the fuel type or fuel mixture such that the HAPs calculated emissions rates are less than the applicable limits. A new analysis is required every 5 years. New fuels or mixtures would require a recalculation and a new plan. The Health Based Compliance Alternative allows the calculation for chlorides using a table lookup to determine if there is a health based impact. If not, the unit would be in compliance. If so, specific facility modeling is also allowed if desired. If any of the parameters in the eligibility demonstration change in a way that could result in increased HAP emissions, a new analysis must be submitted.

On the legal side, as a result of a law suit, there was a reconsideration granted by EPA to review certain provisions in the table look up and treatment of total selected metals. There were some revisions, but no change in the compliance date. Another law suit challenged the Boiler MACT under its treatment of hazardous waste combustion. Boilers that burn **any** waste material that is considered hazardous are considered to be waste incinerators and fall under the rules for waste incinerators (more stringent). The word "**any"** was considered critical and the entire Boiler MACT rule was vacated on June 8th. Lacking a request to stay the vacature, the Boiler MACT will have to be redone by EPA. (The

Notifications are required for initial determination, performance testing, performance evaluation, and initial compliance demonstration. On notification of compliance status, there are a number of requirements in addition to the test report including all test results, choice of TSM or PM limits, choice of performance testing or fuel analysis, any deviations form emissions limits or work practice standards, and descriptions of all effected sources including subcategories, capacity, control devices, etc. Reports and record keeping are critical. There are semi annual reporting requirements. All notifications, semi annual reports, records of performance testing, fuel analyses, compliance demonstrations, opacity observations, CEMS, CMS, CPMS, COMS records, fuel use, and operating hours must be recorded and maintained for at least 5 years. Care needs to be taken when changing over computer or data acquisition systems. Sometimes old data stored on discs cannot be read by the new system.

New (and reconstructed) units already had to be in compliance if started after January.13,2003. Construction means the on site fabrication, erection, or installation of an affected source. Reconstruction means the replacement of components of an effected source to such an extant that the fixed capital cost of the new components exceeds 50% of the fixed capital cost that would be required to construct a new unit and it is technologically and economically feasible for the reconstructed source to meet the relevant standards.

Under the rule, new small gaseous fuel units had no emissions standards. New gaseous fuel units have reporting requirements. New small liquid fuel units also have no emissions standards for distillate fuels. Residual fuels carry a CO requirement. New unit CO work practice requirements apply to new solid fuel units, new large liquid fuel units, and new large gas fuel units. Compliance extensions can be requested up to 120 days before the compliance date if there is a legitimate reason for being "unable to comply". The Title V compliance board is the decision maker rather than the EPA.

Start up, Shutdown, and Malfunction plans are required for affected units. If there is an emissions limit or work practice standard, there must be a written start up, shutdown, and malfunction plan (SSM). The plan must only be submitted on request of the Agency or the public. For such requests, it is important to request protection of proprietary information. The purpose of the SSM plan is to ensure operation and maintenance of the affected source in a manner consistent with safety and good air pollution control practices for minimizing emissions. During an SSM event, emissions should be minimized to the greatest extent , which is consistent with safety and good air pollution control practices. The plan should help ensure that the source is prepared to correct malfunctions as soon as practicable after the occurrence in order to minimize emissions of HAPs. Provided an SSM plan is written, the source must be in compliance with emissions limitations at all times, except during periods of start up, shutdown, and malfunction.

The source must write a plan, operate in accordance with the plan, and demonstrate compliance through records. A deviation that occurs during an SSM event is not a violation. Detailed procedures for operating and maintaining the affected source during the SSM events in manner that minimizes HAP emissions and a program for corrective action for malfunctioning equipment are essential elements of an SSM plan, as well as proper maintenance of the equipment. Plans must be revised whenever there are process changes, new equipment additions, or modifications to existing equipment. If an unanticipated event occurs, the plan must be revised within 45 days. The plan must be kept on site for the life of the source. After revisions, the previous version must be kept for 5 years. Records must be kept of the occurrence and duration of each SSM event, information to demonstrate conformance, and actions taken during any event that deviate from the plan procedures. Immediate reports are required for SSM events that are not congruent with the plan and the source exceeds the emission limits in the standard within 2 working days (confirmed in writing after 7 days). Periodic reports are due 30 days after each semi annual period. These can be submitted with other required periodic reports.

In the preparation of an effective SSM plan, historical records need review, along with plant standard operating procedures, plant personnel involvement, and any HAZOP procedures or health safety procedures in existence. Manufacturers' documentation should be extensively utilized. Training is an important aspect of preparation for all of these requirements. This training should be implemented well in advance of the compliance date. Boiler MACT rules will likely get incorporated into the Title V permit. The amount of actual language vs cross-referencing is open. Emissions limits will be included. There is an "obligation to comply" to any other regulations under Title V.

[Court mandate issued July 30, 2007, and the rule was vacated latter that day.]

NSR reform has redefined baseline actual emissions, projected actual emissions, and "could-have-been-accommodated" exclusion. For existing units, the highest 24-month period in the last 10 years can now be used as a baseline (rather than just the last 2 years). The projected actual emissions are those projected for emissions after the project change for the next 5 years. These shall exclude those emissions that "could have been accommodated" and those related to "increased utilization from product demand growth". This must include fugitive and SSM emissions. A source can opt to use the old "potential to emit" method.

An example of the "could have been accommodated" exclusion would be a 24 month period with emissions of 480,000 ton/yr, but a maximum month of 45,000 tons, leading to an estimate of 540,000 ton/yr. If these additional emissions would result from increased demand (and does not violate another permit), then an additional 60,000 ton/yr would be excluded from consideration as an NSR trigger. Another concept is a plant wide applicability limit (PAL). "Actual" PALs include existing and replacement units, new emissions limits, and 10-year applicability. PALs are pollutant specific and require minor NSR and Title V permitting, but when in effect, eliminate the need for worrying about repair and maintenance definition, as long as the plant limits are maintained.

Climate change activity has increased dramatically in the last few years. The current administration has somewhat changed direction in that a number of climate change activities have been initiated, compared to earlier positions of "mostly study the problem". The Supreme Court decision in Mass v EPA decided against EPA and ordered EPA to reconsider its decision not to regulate CO2. The EPA has the discretion to not regulate, but must find that CO2 does not cause climate change. Although the challenge was against motor vehicle emissions, the Court found that the plaintiffs did have standing (critical), that EPA had the authority to regulate, and that GHGs fit well within the definition of an air pollutant under the Clean Air Act. The latter would then be used to apply to stationary sources. A number of legislative proposals are in the hopper.

The Clean Air Interstate Rule (CAIR) requires significant SO2 and NOx reductions. The rule was written with electric utilities in mind. However, many states are looking "beyond CAIR" for additional emissions. There are provisions for non-utility generating unit options. The Regional Haze rules require reasonable progress toward achieving natural visibility conditions in all Class I areas by 2064. Existing units may be subject to BART (best available retrofit technology) in order to show progress. The implications are that controls might be required by 2013. Air modeling (CALPUFF) is usually required. States should consider costs of compliance, existing technology, remaining useful life, and the degree of potential visibility improvement. VOC and ammonia are considered on a case-by-case basis.

II. Fundamentals of a Successful Air Pollution Control Project - Panel, Blake McBurney, McBurney Corporation, Moderator

The panel consisted of Bob Fraser of ENSR International, Lauren Laabs of Environmental Resources Management, Jeff Arroyo of Sega Engineering, Dale Pfaff of SP Environmental/Amerex, and Mick Durham of Stanley Consultants.

Bob Fraser reviewed the elements of what has to be done. Upfront planning is a key to a successful project. Resource planning goes a long way to help evaluating steps to be taken. Pollution control projects are not exempt from NSR or PSD determinations. Any physical change requires at least a determination and might need a permit change. Even converting to natural gas might lead to a permit requirement. The cumulative effect of changes needs to be considered. All aspects of the plant operations need to be reviewed including cooling towers, road dust, ash disposal, tanks, conveyors, modeling, stacks, fence lines, etc. Thinking through the project from the beginning and looking at the impacts on all of the plant are crucial to having a successful project.

Lauren Laabs pointed out that it is key to review all of your current permit requirements. There may be limitations in these permits that have "unintended consequences". Space is an important consideration as well as the resources that are needed to operate the equipment. Look for opportunities to recycle and reuse. This is more than just looking at trash. Combining flows can often reduce the capital and operating cost of a project.

Jeff Arroyo reiterated the need for compliance planning. This means staying on top of regulations and permit requirements on a continuous basis. Compliance strategies include fuel switching, alternative fuels, repowering, APC equipment, upgrades and betterments, BOP impacts, and emissions averaging. Conceptual designs for best control options need to be reviewed and double-checked for costs and energy implications. The timing and duration of project implementation needs constant attention. Suppliers are experiencing shortages in materials and labor, which can affect both, cost and schedule. Managing all of these risks is important to project success.

Dale Pfaff pointed out that the project time line and implementation needs to be reviewed, especially if it is more than one year old. As deadlines approach, demand tends to soak up available resources causing schedules to slip. Early involvement of the operating staff is important to making sure that the plant starts up successfully. Bid specifications need to be tailored to the project. Detailed, but standardized, specifications that have to be modified can cause substantial delays. Training is critical to having the project successfully turned over to the operating staff.

Mick Durham pointed out that cooperation amongst the parties is necessary for successful projects. The owner, the A/E, and the contractor need to work together to assure that minimal problems during the contract result. Planning ahead includes identifying who is responsible for what and making sure that all parties sign off on the written plan. Communications or over communications will be needed. Commissioning is the buzzword for the start up phase and needs to transition smoothly into the required testing for demonstrating compliance. Coordination of these two phases is important to getting the project into commercial operation on time.

Blake McBurney re-emphasized the shortages of labor for certain skills and crafts. Biomass projects are "popular" right now as a "green" solution. Many plants think that these plants should sail through permitting. However, the variability of these alternative fuels leads to problems with the databases that provide permit agencies with a basis for emissions limitations. Regulators driving for tighter emissions limits may have consequences for the commissioning and compliance demonstration periods. Many of these fuels have never been used before.

Equipment suppliers make guarantees based upon certain conditions. For biomass fuels, the exact same fuel may not be available at the time of the test. Correction curves and factors need to be agreed upon in advance in order to avoid problems with both performance and compliance. Ideal schedules are unrealistic. Projects are complicated and many minor occurrences can often cause delays. Equipment boundary conditions are normally specified for performance guarantees. These conditions are dependent upon the rest of the plant and its operations. These need to be understood in order to make the various parts of the plant work together. Negotiating the permit is crucial to getting a permit that can be lived with for the life of the plant.

In answer to a question on when to go to the regulators to talk about a project, most environmental consultants have a feel for the requirements at the permit level and attempt to work through most of the alternatives to come down to a proposed approach before going to a permit agency. With regard to the uncertainty imposed by a vacatur of the Boiler MACT, the states will be forced to impose rules on a case-by-case basis. The states can always be more restrictive than the EPA. By the time that the EPA comes out with a new rule, it is not likely to be less stringent. Experience is a key factor. Finding out about other projects that have tried to do something similar and learning from that project will be critical to APC project development and success.

III. Update on The State of Industrial Compliance Coal - Kevin Deschler, Arch Coal Company

Arch Coal is one of the largest coal producers in the US with a leading position in all 3 low sulfur coal basins. They supply 11% of US coal needs. Arch Coal is the leader in mine safety, productivity, and reclamation. They sell 4 - 5 million tons annually to the industrial markets. Over 80% of their reserves are "compliance" coals with less than 1.2 lb/MMBTU sulfur. Arch will be opening up a long wall mining operation in the last quarter of 2007 in the Central Appalachian Basin. This operation will replace another seam that has been depleted. This coal will range in quality from compliance steam coal to metallurgical coal. In an effort to increase the viability of using coal, Arch is participating in an Coal to Liquids project in the West using GE gasification technology and Rentech Fischer Tropsch technology. Carbon capture and storage technology will be needed to continue the use of coal. On of the approaches to de-carbonizing the automotive fleet is to electrify the vehicles. Plug in hybrids are a step in that direction.

In answer to a question on compliance coal for mercury and/or chlorine, experimental work is being done on blending coals to make a compliance fuel. More data is being taken on mercury and chlorine content in the various seams to try to identify the potential for coals that might be characterized as a compliant coal. With regard to the increase in demand for PRB coal coming further east, there have been some issues with rail bottlenecks. The rail industry is trying to address this problem.

IV. Review of Forum Discussions - Fred Fendt, Rohm and Haas Company

Equipment Suppliers Forum - Facilitator, Bill Gurski, Hamworthy Peabody Combustion, Inc.

Bill Gurski provided the suppliers report. The main items were the regulatory uncertainty and the knowledge loss in the industrial powerhouse as companies reduce staff to control costs. Owners know their equipment better than anyone else. Suppliers have experience across equipment lines, markets, and geography. Both knowledge bases can be used to work up cost/benefits for all emissions/efficiency projects. There are many concerns about the regulatory uncertainties hanging over the industrial community regarding emissions limits for an increasing number of pollutants. One issue is trying to optimize how one component impacts other parts of the plant not directly considered. Further, the regulators then see an improved component performance and demand further reductions. This is compounded by the regulators "cherry picking" the limit from another source and applying it to a completely different unit.

Training is an issue as plants are under tremendous pressure to reduce costs to be competitive. In many cases training is assumed to be part of the start-up process. This is complicated by customer requests for increased vendor supply and risk taking. Changes and new technology or operations are often difficult since much of the experienced work force and knowledge base has retired and not been replaced. Capital expenditures tend to be scrutinized with excruciating criteria and must compete with other projects that are often directly related to products rather than indirectly related through the power house. Part of the issue is need for adequate data. This includes cost data, performance data, and financial evaluation data. There is still a lot of variability depending upon the nature of the operation. The way to reduce the uncertainty is more and better data and better communication between the customers and suppliers.

Examples or case studies can provide information that benefits both the owners and suppliers. Both, positive cases (environmental project lead to cost savings) and negative cases (environmental project lead to unintended consequences) are important. Suppliers can assist with illustrating the efficiency and emissions benefits. Translating the larger utility projects into information that is useful to industrial owners would be helpful. Questions for the owners include:

What are the priorities set for emissions/efficiency projects?

Is efficiency quantified?

Does the willingness to complete energy savings projects, in conjunction with emissions projects work up to executive levels?

Many of these ideas and actions need to be brought to the attention of the CIBO Technical Committee. The updated Emissions Control Technology Guidance Document could be a vehicle to provide some of this information. Information when provided; and, can be put on the CIBO web site. There are other sources of information including CIBO, the states, and the internet. Linking some of these sources can be helpful in working up projects..

Jeff Arroyo pointed out that the suppliers are experiencing longer material lead times and equipment and labor shortages. The basic idea would be that CIBO would be the source of technical information to help owners with their projects. The greenhouse gas issue and its uncertainty makes for a more difficult environment. The New Source Review (NSR) process makes any capital project difficult as it might trigger a complete re-opening of an existing permit. If a pollution control project is needed, it may be advisable to pull together other projects and upgrades like energy efficiency since a permit review will be require anyway.

Owners' Forum – Facilitator, Ann McIver, Citizens Thermal Energy

Ann McIver reported on the owners' forum. She noted that in spite of the mandate that was issued yesterday on the Boiler MACT, most of the owners in the meeting were ready to comply with the MACT rules on September 13. This ruling is a classic example of the regulatory uncertainty that industrial owners face. The vacatur of the rules means these rules no longer apply at the federal level. Now there will likely be 50 different rules as states step into the gap while EPA revises and resubmits the rules.

Owners need help with cost and performance data in order to establish what can be done. They need help educating the agencies, in particular. Along with the information on what works, there is a lot of dis-information available on the internet and in the media. We need to be able to separate out the real data from the hype. There was a concern about conservative guarantees by suppliers, which leads to more expensive equipment. Part of the issue is the scope of supply that is out of control of the equipment supplier. As many of these pieces have to work together and changes in one impact performance in another. Projects are more complex and legal consequences are more serious with today's projects. There is a need for a more collegial approach. Project teams need to be established. Teaming arrangements bring their own unique issues. There are still interface issues. They are, perhaps, masked underneath the team leader.

V. **Environmental Rules, Regulations, and Implementation Requirements for the Industrial Sector – Panel**

The panel included; Seth Barna, the Ozone Transport Commission (OTC); Roy Crystal, US EPA of Region 1; David Foerter, Institute of Clean Air Companies (ICAC); Skipp Kropp, the Midwest Ozone Group; Scott Darling, Alcoa, Inc. and Jim Eddinger, US EPA

Seth Barna of the Ozone Transport Commission The OTC role is to work with the states on a regional basis on ozone and to follow up with EPA on the OTC recommendations. The OTC was established by the Clean Air Act and comprises the 12 Northeastern states and DC to ensure the development of regional strategies to reduce ground level ozone concentrations to healthful levels. The OTC has worked with many organizations including CIBO. Initial focus was on mobile sources followed by the utility sector. Now that reductions have been and are being implemented, the industrial sector is exhibiting emissions levels comparable to these other sectors. Progress has been made. Several locations actually came into compliance for the old, ambient ozone standard. OTC has published a technical support document with information about the types of technologies that can assist states in coming into compliance. For boilers OTC is proposing to categorize units by size and type of fuel. For smaller units firing gas, an annual tune up would be required. For units above 500 MMBTU/hr, units would probably have to meet typical EGU standards. Units in between would have a number of options, including trading, offsets, and emissions limits. There is a new NAAQS proposal for ambient standards after the vacature of the current proposed rule. Many of the states will have to submit new State Implementation Plans (SIP) to address the new standards when they are issued.

Roy Crystal of EPA Region 1 (mostly New England) reported on the EPA outreach program to help facilities address compliance issues. Observed compliance problems from inspections appeared to relate to operations and maintenance issues of control equipment, particularly with respect to thermal oxidizers (VOC control) and, to a lesser extent, boilers. The focus on sources and areas with elevated health risks lead to more strategic emphasis on major urban centers, particularly Bridgeport and New Haven, CT. EPA has learned that it is necessary to work cooperatively with the states, DOE, and industry associations in order to make these programs work.

EPA is placing heavy emphasis on the proper O&M of boilers, steam systems, and air pollution control systems. For most of these units, the annual tune up is part of the permit requirements and should be scheduled and performed to meet regulations. Region 1 has held a number of workshops on air toxics, VOC, combustion & cooling, and energy conservation. The short term goals are increased understanding of compliance requirements and energy conservation options. Surveys are done after each workshop to try to assess the effectiveness. At a recent workshop in Massachusetts, only 22% of respondents were aware of the fact that gas fired boilers in the range of 10 - 50 MMBTU/hr required an annual tune up. Even after the workshop, only 66% were now aware. Following a New Haven workshop, Connecticut has experienced a number of new cogeneration projects as new incentives at the state level have been put in place. More work is needed.

In one case study, a hospital in New Haven was undergoing a facility expansion. The proposed boiler would have fired gas and residual oil. There was local opposition to the project. The City of New Haven asked for some assistance from EPA. EPA provided contacts at another location that had successfully done a cogen project. Ultimately, the hospital decided to go with a 1.8 Mw cogen system which would provide most of their electric demand, a substantial quantity of steam, allow the reduction or shutdown of some older boilers, and still reduce overall emissions. EPA is actively promoting systems analysis in order to look for potential efficiency improvements to reduce emissions.

There is an EPA tool for management of buildings. There is a DOE tool for analyzing steam systems. There is also another DOE tool for efficiency improvements. EPA has a partnership program for combined heat and power. There are a number of programs and information available on the EPA web site. In particular, there is an applicability determination site for MACT and NSPS standards at http://cfpub.epa.gov/adi. There are a number of other programs and partnerships that are listed on various parts of the EPA website. The states also have a lot of information on their websites.

Skipp Kropp, Midwest Ozone Group, reported on the Regional Haze Consultation Process. The Regional Haze Rule requires that visibility in the US be brought back to "natural levels" by 2064. Regional Planning Organizations (RPOs) were set up to show progress toward that goal. State SIPs are due in December, 2007. These are CenRAP, Midwest RPO, MANE-VU, VISTAS, and WRAP. There is not a lot of guidance on the consultation process.

CenRAP has 3 consultation process areas: a Northern Class I, a Central Class I, and a Breton Island consultation process. Breton Island is an entity by itself because it is a Class I area and is not projected to meet its interim guidelines. For the Northern Class I, there are 4 Class I areas. This group recently issued for comment its recommended guidelines for reasonable progress. MANE-VU has posted information on costs for comment. VISTAS hosted a consultation meeting. In VISTAS, the ammonium sulfate is the primary contributor to haze. Greatest improvement in visibility comes from SO2 reductions. NOx had little influence in this region. SO2 areas of influence were defined for each Class I area. In 2018, coal fired electric utility boilers and coal fired industrial boilers are the largest sources of SO2 emissions in every SO2 area of influence.

Control options and costs were provided to states. Information on costs need to be given to the states to help assure that the states are using more realistic figures. Upwind sources need to be consulted before final SIPs are put out. In VISTAS, the regional progress goal should be reported using deciviews with one significant digit after the decimal point (rather than 2). In reality, modeling may be able to get to within 2 significant figures in front of the decimal point. The Federal Land Managers have to review state SIPs. They do not really have the manpower to do this, as well as review all of the permits for new units, and carry out the rest of their responsibilities. The FLMs want to get SIPs 60 days ahead of release for public comment.

EPA has published some Regional Haze guidance in draft form. Some of the language is not a model of clarity and many questions have resulted. EPA has stated that the guidance does not trump the Clean Air Act or the Regional Haze Rule. Any discrepancies would defer to the Rule. Uniform reasonable progress (i.e. straight line) has been understood to be applicable. However, if controls are not being imposed in a given state or area, EPA may require the state to impose controls in the SIP. Another factor is an additional figure of merit besides $/ton. A $/dv was proposed, but since the deciview figure falls off with distance, a $/inverse megameter should be used. This concept has yet to be finalized.

David Foerter, Institute of Clean Air Companies (ICAC), pointed out that the ICAC is a national association of companies manufacturing air pollution control equipment headquartered in Washington. Membership is about 100 companies. Regulatory requirements drive air pollution control markets. The VOC market is likely to remain flat due to uncertainties. NOx control markets will peak in 2007. SO2 markets are expected to increase through 2010. PM markets peak in 2007. Greenhouse gases are currently up in the air. The markets are currently driven to distraction by the GHG issues, at the expense of other criteria pollutants.

The future role of industrial sources will be more prominent as the larger sources implement controls. The role of control technologies is to provide straightforward compliance. Well informed sources will make good purchasing decisions. Process monitoring can reduce control costs. Good project planning can result in cost savings as older equipment is upgraded along with the addition of pollution control equipment. Many of our units are on older units where we are adding new equipment.

New uses for existing technologies include reagent injection (ie. ammonia, oxygen, carbon, alkaline sorbants, etc.), electron beam systems, and catalytic systems. Doing more for less includes using less reagents, less energy, and less materials. This involves flow controls, monitoring, and tighter control systems. Integration of technologies include wet ESPs, SNCR/SCR hybrids, and multi pollutant control devices (ie fabric filter with SO2, SO2 scrubber with chlorides). New pollutants include mercury, SO3, condensables, PM2.5, and potentially GHGs. The MACT rules have had a tough go in the Courts. Several MACT standards have been vacated, requiring more work before a standard is in place.

Regulatory delay hurts rather than helps, partly due to uncertainty and partly due to the delay in coming into compliance.

Scott Darling, Alcoa, gave an industry perspective on such issues as Boiler MACT, NAAQS, PM2.5, NSR, and ozone. The demise of the Boiler MACT rule has left the states up to themselves on how to proceed. EPA needs to provide some guidance to the states. States with affected sources need time to digest and implement the guidance. States need to inform sources on how to deal with rules and limits that were incorporated into a Title V permit as a result of the proposed MACT rules.

The new PM NAAQS has replaced the 1-hour rule with the 8 hour rule. All boilers are not alike. There are a wide variety of boilers with different operating requirements. There is a wide range of coals, waste fuels, biomass, oils, and gases. These features make a one size fits all approach difficult to implement. Industrial sources often have to deal with international competition and do not have the ability to raise rates to pass on resources.

High electrical demand days often bring on peaking units that likely don't have controls. These same days have the worst ozone problems. Focus on these aspects of the problem may produce a better result. The I-95 corridor and motor vehicles are a major source for ozone. NSR doesn't really work. Many efficiency projects are rejected due to NSR. Those are the easy ones to assess. There are other problems with NSR, such as routine maintenance, that may or may not trigger NSR. All of this creates significant uncertainty and delays progress.

Jim Eddinger of the US EPA reported on some of the rules that apply to industrial boilers. The Boiler MACT rules have been vacated yesterday (July 30, 2007). Boilers that were not covered were those listed in another source category and those considered to be area sources. One of the problems was the overlap between waste incinerators and boilers. Petitions for reconsideration included: common stack testing, the lack of standards for all HAPs, and the Health Based Compliance approach. These were considered and modifications were issued. However, the litigation came about as the problem of waste fuels, the problem of units with no emission reductions, and the work practice rules.

Since the rule was vacated, the issues of health based standards and the health based control alternatives have not been addressed. Since the rule is vacated, Section 112 (j) need to be followed. Requirements for 112 (j) applications are in the May 30, 2003 Federal Register. With regard to revisions, the schedule requested by EPA is to be the same as for area sources with extension. Revisions will include the removal of waste burning boilers from the database, revised emissions limits, MACT floor emission limits for the no reductions boilers, and the definition of solid hazardous waste. For the NSPS, the final revisions were issued in February 2006. Final amendments were issued in June 2007. For oil fired units there is no PM limit for low S oil and CO instead of opacity. For coke oven gas, the rules were changed to look like natural gas. For Area Sources there is a request for time extension in front of the litigants.

VI. Annual ABMA Gas & Oil Fired Burner Manufacturers Panel

The panel consisted of Bill Gurski and John Guarco of Hamworthy Peabody Combustion, Inc., Dave Thornock of Johnston Boiler Company, and Tim Webster of Todd Combustion.

Bill Gurski provided some considerations for industrial users including boiler performance, safe operation, efficiency, simplicity, familiarity, analysis of all fuels and interactions, fuel delivery equipment, staffing reductions, experienced commissioning/startup personnel, and emissions reductions as a "necessary evil". For gas firing, 15 ppm NOx (just under 0.02 lb/MMBTU) has become the new benchmark (compared to 30 ppm). In some states, requests are for 9 ppm. Hamworthy Peabody has introduced a new ultra low NOx burner that requires less flue gas recirculation and less steam injection than the previous design. The 15 ppm NOx level is achievable with moderate FGR. The design is based upon the prior model, of which 2000 are in operation. Very little in the way of control modifications are required. The burner can handle all types of gaseous fuels. Most fuel delivery systems can be accommodated. At a recent unit installation of a 150 kpph package boiler, the contract called for 16.5 ppm NOx. The actual measurements indicated 14 ppm at full load and sub 10 ppm below 80% load with 25% FGR. The turndown ratio was 10:1 with no ramp rate restrictions. For most applications the burner housing will fit within the existing burner port.

Dave Thornock of Johnston Boiler reported on firetube boiler/burner emissions. Firetube units are different that the larger watertube units. Fuels include biofuels and natural gas. With regard to biofuels, a wide variety of sources are being utilized for boiler fuel, including oils, fats, grease, tallow, animal parts, and food wastes. NOx and SO2 production still comes from the same sources. However, unburned hydrocarbons, VOCs, and dioxins are very fuel specific. NOx levels are directly related to fuel bound nitrogen. Sulfur levels are directly corresponding to the sulfur level in the fuel. For bio-fuels, the ultimate analysis, viscosity, consistency, heating value, and other properties all need to be known for adequate design. The heating value of many oils and greases are similar to fuel oil.

Due to the lack of data with fuels, a number of the processors did some testing on one boiler with 15% FGR. The NOx levels were measured for a wide variety of these fuels. Tallows and yellow grease were amongst the lowest at about 80 ppm. Chicken fat was the highest at 120 ppm (burns quickly and hot). Natural gas firing without FGR was less than 50 ppm. Boiler efficiencies ranged from 74% to 80%. This data was reported in a paper by T. Adams, et al, 2002. This paper has become the baseline for such units. Actual combustion testing is preferred to get a more accurate level for a guarantee.

Problems include plastic solids that might have come in with processed oils. These melt in the oil, but plate out on heat transfer surfaces. The ash in the fuel can foul the boiler. Fuel constituents may react with refractories inside the furnace. Strainers are needed to remove bone chips and other solid contaminants. For these boilers, every unit is tested at rated pressure and load before shipment. Providing the fuel for a test burn gives the most accurate results. With the recognition that some of these fuels can be burned, the price has come up. Recently, one of the units was firing natural gas because it was cheaper than tallow. Land fill gas can still be obtained if the user can work with the fill owner, particularly to reduce other problems (odor, emissions, etc.).

With regard to gas firing, the standard is 12 ppm for units at about 20 MMBTU/hr. This is expected to go down to 9 ppm. Methods for NOx control include flue gas recirculation, premixed combustion, mixing, steam or water injection, fuel/air staging, and fuel dilution. Johnston Boiler teamed with GRI to develop a low NOx burner. This burner was a premixed burner with forced internal recirculation. A high velocity jet pulls combustion products back into the flame zone from the center of the flame. This avoids the need for FGR from somewhere else in the boiler. Applications range from 80 to 2500 horsepower. At one 300 hp unit, the NOx levels ranged from 8 - 10 ppm on gas. On a 2500 hp unit, the NOx levels ranged from 4 - 7 ppm. A total of 48 burners have been sold.

Tim Webster of Todd Combustion reported on some of their new technologies and advancements in burner applications. Ultra Low NOx burners started in California (9 ppm on gas). These levels are impacting smaller boilers (100 hp or 3,500 pph). Population centers are requiring these lower levels. California is now pushing for 6 ppm. Firetube boilers are getting larger (up to 2500 hp or 86,000 pph). These are being used by chemical plants, hospitals, universities, and ethanol plants. The high firing rates and smaller furnace sizes present a considerable challenge to making sub 10 ppm NOx.

For most locations, back up oil is required (#2 oil). Oil companies are creating distillate oils that are very low in nitrogen content. Burners for these furnaces are stable at full load and 7 ppm NOx with stack oxygen levels at 3 - 4%. Variable speed drives are being used to reduce horsepower requirements of the system. Efficiency is difficult to sell to the contractor that is buying the pieces of equipment. The owners need to get into the process to request the efficiency improvement.

In California, a compliance extension was given to those units that could reduce to 6 ppm. Small rapid mix burners had demonstrated stability at less than 3 ppm NOx. The concept was then taken to group small burners together to act in concert as a "cell". Zone biasing could be used for additional NOx control. At relatively high FGR levels (40% FGR), the NOx level in a field test (May 2007) were less than 5 ppm. Emissions were measured by an independent source testing company due to the low levels involved. Future development opportunities include lower excess air, lower FGR, lower draft loss, improved monitoring and control devices, and single digit NOx on refinery gases.

VII. Particulate & Multi-Emissions Control Technologies For NOx, HCl, SOx and Hg Compliance or Advantage - Panel

The panel consisted of Jay Crilley of Mobotec USA, Inc., Kevin Dougherty of Fuel Tech, Inc., Sean McMenamin of Peerless Mfg, Co., Mike Cornnell of Wheelabrator Air Pollution Control Inc., and Brad Rogers of GE Environmental Services.

Jay Crilley reported that Mobotec has joint ventures for two technologies called MinPlus (non carbon based mercury control) and MagMill (pyrite rejection system for a pulverizer). The company has licenses for several processes for mercury control, chlorine control, and sulfur control by various additive injections. The Mobotec system is intended to help control NOx, with the potential to control SO2 and mercury with various additives. At a unit at Taconite Harbor in Michigan, the low NOx system has been installed. The additive for sulfur control will start soon along with an SNCR addition. Finally the mercury process will be added. The opposed rotating overfire air system (ROFA) has been installed at a number of utility units for NOx control. Several industrial units have applied the contract. At an industrial unit in Cedar Springs that fired bark and coal, the LOI was high for the ash. After the ROFA installation, the LOI went from 28% to 8.5%. The unit was able to go from burning 30% bark to burning 70% bark. The fuel savings amounted to $1.5 million/yr. The NOx was reduced from 0.29 lb/MMBTU to 0.20 lb/MMBTU. Particulate matter was reduced from 0.11 lb/MMBTU to 0.07 lb/MMBTU.

Kevin Dougherty of Fuel Tech reported on their latest SNCR technology. Fuel Tech uses urea based SNCR systems to reduce NOx. There are about 450 installations world wide. Roughly 360 are retrofits.

There are 350 industrial units. There has been a lot of activity in China, particularly around Beijing due to the coming of the Olympics to China. NOx controls run from low NOx burners and staging through SNCR and SCR. These technologies can be used in combination to optimize the performance for a particular furnace and fuel. SNCR can be installed at multiple levels to provide flexibility and load following. One advantage of using urea is that the droplet size can be controlled to get the penetration that is needed to mix the material in with the flue gas.

The SNCR system has been used on a wide variety of fuels ranging from chicken fat to oil to gas to wood to coal. At one hazardous waste combustor, NOx removals ranged from 40 - 55%. With the large number of installations, Fuel Tech will offer a full contract price and money back guarantee. When ammonia slip and high NOx removals are required, the SNCR and SCR system can be combined. The ammonia slip from the SNCR becomes the feed to the SCR. Allowance credits vary depending upon the ozone season and the potential for CAIR rules. For cost studies the annualized costs are for all installation costs. The capitalization factor was 12.5%. The cost/ton ranged from $1000/ton to $5000/ton depending upon the ozone season, size of the boiler, fuel, and location. The project turnaround times are on the order of 6 - 9 months. Combined technologies require lower levels of resources and labor.

Mike Cornnell, Wheelabrator Air Pollution Control Inc., reported on dry scrubbing systems. There are dry injection systems, duct injection systems, and spray dryer absorbers. Dry injection systems can attain up to about 50% SO2 reduction while spray dryer absorbers can achieve up to 95% reduction. In the primary aluminum industry, dry injection is used for sulfur and chloride control. The dry material is collected in the particulate removal system. In the duct injection system, a length of duct can be used to increase the contact time of the solids. The performance can be improved by wetting the solids prior to injection. Partial recycle from the particulate collection system can also be utilized. The acid gas is more easily absorbed into the liquid layer on the particle mobilizing more of the additive. The flue gas dries the product by evaporating the water. In a spray dryer absorber, a slurry of additive is sprayed into the flue gas. The flue gas evaporates the water and the SO2 is absorbed. A baghouse is used to collect the fine particles. Some additional SO2 removal is obtained as the flue gas passes through the filter cake.

Brad Rogers of GE reported on integrated Control Solutions for mercury, PM, and NOx. Mercury regulations in the Boiler MACT came ahead of the utility CAMR rules. This was thought to be an advantage for industrials as resources for Hg control would not be completely tied up by the utilities. Some states have now required more stringent mercury reductions than the CAMR rule.

Activated carbon has dominated the choice of technology as ACI has shown the capability to remove more than 90% of the mercury. Actual removal depends on the fuel and the type of unit. GE has been working on a combustion optimization system looking at both mercury and NOx. Sorbent injection required the use of CFD modeling. The particulate system needs to be optimized as well. The target market is units less than 300 Mw firing coal without SO2 scrubbers. Technology layering can reduce NOx emissions. Fine biomass (sawdust) can be used for reburn fuel. Overfire air and SNCR can provide further reductions. Low NOx burners provide for the initial reductions. Activated carbon can then be used for mercury control. Improved combustion techniques help to mitigate the impact of mercury capture in the particulate system.

By optimizing the combustion, more mercury is likely to be picked up by the carbon in the ash. As a result, the sorbent injection requirement can be reduced by up to 20 - 40%. Field tests have been carried out at 3 utility plants. Preliminary results showed that under normal conditions, the mercury emissions represented about 70% of the total mercury. With the combustion optimization, this figure improved to 44% of the total mercury. With the activated carbon, the emissions were on the order of 5% of the total mercury. Activated carbon requirements were reduced 30 - 40%.

GE is also offering a MAX-9 system for an electrostatically enhanced pulse jet fabric filter. This system creates a more porous dust layer on the fabric filter. A test unit on an 80 Mw plant has demonstrated 40% improved mercury reduction and 50% lower pressure drop. The air to cloth ratio was 6:1 compared to 4:1 for a typical baghouse, resulting in a smaller piece of equipment. The plant has 3 boilers firing coal and biomass. The flue gas from all 3 is ducted to the single baghouse

VIII. Multi Emission Technology Development - Rich Crews, Process Engineering & Mfg., Inc.

Particulate Matter can be filterable or non-filterable. The non-filterable is generally that from gaseous compounds that condense into particulates. Wet scubbers can help to reduce the level of non-filterable particulates. The source of water is important to the cost and operation of the scrubber. A derivative of the jet scrubber was used as a test unit for a particularly difficult application. The unit was a 12 Mw biomass boiler with spreader stoker, multiclones, and ESP. The unit also has FGR and ammonia injection for NOx control. Although the unit was in compliance for particulates, there was an opacity problem. The scrubber has an inlet section, a length of duct, a turn around section, a fan, and then off to the stack. The unit is in sections so that any section can be turned on and off independently. There were 3 tests run at a high flow of 19,000 CFB with no chemistry. After the base test, dolomite was added to the scrubber water. The SO2 went to zero. The non-filterable PM was reduced by 82%. In the first test, only cooling tower blowdown was used. In the second test with dolomite, the condensable inorganics were reduced by 96%. The sulfates were reduced by 49%. No oxidizer was used in any of the tests. Chlorides and ammonia were taken up into the scrubber water. No additional blowdown was done during these tests. During regular operations, a small amount of water was blown down and used for dust control on the fly ash pile.

IX. Boiler Efficiency Fundamentals Workshop – Norb Wright, Energy Efficiency Operations Consultant

The objective of the presentation is to go over the subject of energy efficiency in a practical/real world fashion considering the definition of energy efficiency, the measurement techniques, efficiency enhancement techniques and devices, and efficiency issues in the balance of the plant. Energy efficiency is basically the amount of energy transferred from one form to another for useful work. It can be the output, in energy, divided by the input, in fuel energy. This is not as simple as it may seem. It can vary by load, by fuel, by design of the system by emission control requirements and by operator performance. As rules of thumb, a 1.9% change in Excess Oxygen is equivalent to a 1% change in efficiency; and, a 40 ^{o}F change in boiler fluegas exit temperature is equivalent to a 1% change in efficiency.

There are ways to optimize energy efficiency through the application of economizers or air heaters or enhanced combustion control systems and variable speed motors and drives. Each system is different and operation and maintenance, on a plant specific basis, can play an important part in achieving optimum system performance. To do this an energy/operations audit for a plant is an important consideration along with an annual tune-up. The practical needs and pitfalls of going through the process and optimizing efficiency are as numerous as there are different plants and systems to be considered. A copy of CIBO

Energy Efficiency Guidance Document and Energy Efficiency White Paper are to be included on the Conference CD with Norb's presentation

X. Energy Efficiency as an Emission Control Technology - Ron Dechene, Auburn Systems, LLC

Rapid response bag leak detection (using triboelectric technology) can be used to actually locate a failed bag inside a baghouse. With appropriate software, reports can be generated that will satisfy EPA reporting requirements. Auburn adopted the Open Process Connectivity protocol (OPC) so that the software can be connected to any other system using an OPC interface (over 80% of North America). The Auburn "Vision Suite" system consists of a recorder, a presenter, and a reporter. At a fluid bed unit, a baghouse with 6 modules was set up with this system. The NJ DEP is publishing a paper describing an approach to utilize environmental control monitoring as an aid to improving efficiency. Linear programming is used to optimize the fuel use in an oil an gas fired units to minimize emissions and fuel costs simultaneously. The system records real time data (and events/alarms) to a database, organize the data for display to a screen for the operator. The reporter creates reports from the data. The system can sit over the control system, or just act as an advisor.

XI. Energy Efficiency Upgrades with Control Modifications - Dave Pasciolla, Automation Applications Inc., LLC

AAI is a systems integrator with energy management as a core application. While these systems cut across all industries, a majority of the projects have been in the petrochemical and pulp and paper industries. At a paper mill in Canada, the biomass unit was pretty much base loaded on the standard fuel, with other waste fuels in the plant supplementing the firing. Many of these units have "legacy issues". These are experience based operations ("the way we always did it") rather than data driven. The project goals include environmental compliance, more biomass capacity, improved stability, and increased efficiency. Alstom Canada was the prime contractor and selected AAI to work with the control system. One of the keys to successful operation, is consistent operation. Even if an operational concept is incorrect, consistent application of the concept will rapidly show up the problem and lead to corrective action. Reducing the amount of operator intervention is one means of providing consistency.

The control solution was specifically designed for multi fueled boilers with separate masters for each boiler. The BTU fired estimated was inferred by consumed air. (This is possible because the BTU/lb of air released is approximately constant for all hydrocarbon fuels.) All load changes need to be coordinated. This is particularly important for units that experience wide load swings. The consumed air control maintains a constant heat release and infers the BTU feed based on hog fuel firing. The oxygen analyzer becomes a critical process analyzer as well as total air flow. A reliable, continuous air flow measurement is required. This approach eliminates variance due to the biomass BTU content that allows operating closer to maximum limits. The air distribution system was determined empirically so that the air can be properly distributed for all load points. This approach provides the best environment for good combustion. Predictive pressure control allows control movements that anticipate control requirements for the desired header pressure rather than the current pressure.

In a sample run, the hog fuel flow was increased by 50%, resulting in a reduction in the gas flow by 50% while the header pressure remained constant. For this project, the steam from the biomass was 90% and higher; fossil fuel use was minimized; 3.0 - 3.5% oxygen was achieved; carryover was reduced; thermal efficiency increased 1 - 2%; header pressure was controlled; and emissions reduced.

XII. Burner and Air Control for Emission Reductions and Combustion Optimizations - Bob Benz, Benz Air Engineering Co., Inc.

Bob pointed out that emissions control can result in fuel savings. With proper air/fuel ratio and good controls, the NOx levels can be reduced, the excess air can be reduced, and the fuel use can be reduced. At low excess air levels, the combustion process competes with the NOx formation. Normal operation involves fixed speed fan with damper control. This normally means a higher excess air is required to assure that enough oxygen is present everywhere. The use of variable speed drives for fan controls provides for much closer fan control. This approach takes advantage of the fact that the speed control always keeps the operation on the proper side of the fan curve. This allows for operation at oxygen levels as low as 0.7% oxygen on an older existing burner with 19 ppm NOx.

On a 1950s vintage unit with 500F air preheat and 4 ring burners, the NOx was reduced to 18 ppm on gas and 28 ppm on oil. The boiler efficiency increased from 76% to 85%. The fuel savings were $6,000/day. The turndown was 100:1. The payback was 2.2 months. Most conversions have fuel savings due to the reduced excess air that result in simple payback of 12 months or less. Benz Air will bond performance guarantees. At an industrial unit in California, the low NOx system was installed in combination with a SCR. The NOx level was 1 ppm and the boiler efficiency was 95.1%. With these high overall efficiencies, significant CO2 reductions also result.

XIII. Fuel Additives for Efficiency Improvement and Emissions Reductions - Kevin Snape, The Lubrizol Corporation

Lubrizol provides additives that help reduce corrosion, reduce emissions, reduce deposits, improve heat transfer, and improve boiler efficiency for heavy oil firing. Boiler efficiency is improved as a result of reduced deposits and increased combustion. Lower excess air levels provide an overall efficiency increase. For heavy oils, vanadium control is key to minimizing corrosive deposits. Magnesium oxide ties up vanadium and SO3 as magnesium vanadate.

At a 150 Mw unit burning a high sulfur, high vadandium residual oil, the fuel economy improved by 3%, particulate emissions were reduced by 34%, SO3 emissions were reduced by 50%, and unburned carbon was reduced by 22%. This test ran for 18 months. At a blast furnace unit, the additive was used to allow more utilization of heavy oil to displace coke.

The trial methodology starts with a clean boiler followed by one week of operation without additive and then the additive is deployed for a length of time depending on the goal of the test. From a fuel economy standpoint, reductions in acid dew point, unburned hydrocarbons, and low excess air leads to a 3 - 3.5% reduction fuel cost. For the 150 Mw unit, the fuel savings amounted to $1.5 million/yr. There can be additional savings from emissions credits/allowances where applicable.

XIV. Clean Combustion System on a Stoker Fired Boiler - Keith Moore, Phenix Limited, LLC

This system is a hybrid gasification system combined with a stoker boiler. When fuels are gasified at high temperatures the resulting products go through a myriad of compounds. At particular windows, there are compounds where sulfur exists as a solid. If calcium is added at this point, a solid (or liquid) calcium sulfide results. This technology is based on the Rockwell International slagging combustor process from the late 70s/early 80s.

The initial operation runs at a stoichiometry of about 0.4. The refractory lined vessel provides for a high temperature gas. The coal ash, along with the calcium sulfide, are melted out as slag. The resulting gas is a fuel gas that is low in sulfur with all of the fuel bound nitrogen released as molecular N2. This gas is directed to the boiler where the remaining air is introduced. As this is a relatively low BTU gas, low NOx formation results. Air is staged to avoid thermal NOx formation.

For the stoker unit, the customer was able to use local Illinois coal without prep as opposed to compliance stoker coal. The SO2 emissions have averaged 0.72 lb/ MMBTU and the NOx emissions have averaged 0.05 lb/MMBTU. SO3 emissions have been near zero. About half the ash is slagged out. The rest goes out as flyash. The operation control range is roughly down to 60% load to maintain slag flow.

CASE STUDIES

XV. Mercury Testing at Cornell's Central Heating Plant - Stacey Edwards, Cornell University

Cornell operates a central heating plant as well as water treatment plants. The steam system has 6 boilers with a total capacity of 600,000 lb/hr. Fuels include coal, oil, and gas. Cogen capacity is 8 Mw. There are 2 stoker units, one from 1949 and one from 1981. The units fire typical stoker coal. Coal sampling started since 2002. Original grab samples showed substantial variation. In the last year and a half, ASTM sampling was instituted. This resulted in a much tighter average mercury level. With the better sampling, the average was about 7.2 lb Hg/trillion BTU. Recently, the average dropped consistently to 5.4 lb Hg/trillion BTU.

Since the early data showed so much variation, stack testing was the approach deemed necessary to demonstrate compliance with the MACT rules. Stack testing began in early 2006. The Ontario Hydro method was used to get speciation. This was compared to sorbent trap method. Reducing the exit gas temperature from 362 F to 325 F did not result in a reduction of mercury in the flue gas. Fly ash samples were taken from the different modules of the baghouse. The first modules were relatively coarse and got finer through the later modules. The specific surface area for the ash was quite low (2 - 3 orders of magnitude lower than activated carbon).

The mercury speciation data indicated that the mercury was 85% oxidized. As a result, Powdered Activated Carbon (PAC) injection was tested. Three different materials were tested including bromine activated carbon and lime/bromine activated carbon. The PAC was injected before the baghouse. The load has maintained constant along with the oxygen level and temperature.

A total of 23 runs were done measuring the inlet and outlet mercury level. The data varied considerably, but, interestingly, were all lower than the MACT level (inlet and outlet). In some cases, the mercury was higher in the outlet than the inlet. The ash samples were analyzed for mercury. At least in these cases, some mercury was detected. However, different labs produced different results and often used different methods. Mercury material balances were impossible. The lessons learned include learning about conducting test programs; no real standards for mercury testing and analysis; sampling procedures matter; even stack testers do things differently; work with the stack tester; flexibility is important; mercury CEMS might allow the identification of spikes that could skew sampling data; testing precision has limitations; and these limitations impact the accuracy of the results.

Compliance testing was done in April, 2007 as load demand would not allow full load testing over the summer. The tests showed full compliance. However, it was not possible to determine if any mercury capture was obtained. Cornell is seeking funding for more testing, as they would like to be able to control the mercury emissions level rather than take what comes with the coal.

XVI. Powerhouse Upgrade for Compliance at Notre Dame - Paul Kempf, Notre Dame University and Steven Bergdolt, Cummins & Barnard, Inc.

Notre Dame has 6 boilers to supply a total of 735,000 pph steam at 400 psig, 750 F. There is some cogeneration as well as some diesel generation. There are a number of chillers for the HVAC requirements. Studies were initiated in early 2004 to look at MACT compliance. Testing started in September 2006. The data was variable as noted by Cornell. Additional stack testing was performed in 2006. Results were delayed due to sample submissions to outside labs. Test results indicated that the coal fired units would not be in compliance.

The State of Indiana adopted the MACT rules, so Notre Dame will have to comply. A one year extension was requested and granted. It was decided to add 2 new bag filters with sorbent injection to control particulates, chlorides, and mercury. Economizers were added to reduce stack temperatures to below 350 F. New ID fans with variable speed drives were selected. The existing multi clone collectors on the 2 older units and the ESP on the newer unit were removed. The ash handling system had to be modified to accept ash from the 2 pulsed jet fabric filters. These units are indoor units with very little space available. The new bag filters are being located between the boiler house and the water tower. The ductwork will have to come out of the building, go into the bag filter, and return back to the building and into the existing stack. Site work has begun. Despite regulatory uncertainty, compliance is expected by September 2008.

XVII. Dry Scrubber Installation & Operation at Virginia Tech - Byron Nichols, Virginia Tech

Virginia Tech has 2 systems currently in use with 2 chain grate stokers each supplying 100,000 lb/hr of steam at 600 psi and 750 F. There is some cogeneration. The new boiler was installed in 1997 to meet BACT requirements. The new APC system was installed on the older boiler (1959). There was extensive stack testing on the existing unit with emissions controls.

The new system was to be designed to meet the Boiler MACT and foreseeable future emissions standards.. Prior experience would be factored into the design. The new system would have to fit into the available space. Coal storage of 7 - 10 days was deemed necessary to account for severe weather events. A hydrated lime system with baghouse is used for both particulate and sulfur control. Material from the hoppers is collected and recycled with a portion going to disposal. The collected material is moistened in a conditioning drum and injected into a venturi section of the flue gas duct. Water requirement is proportional to boiler load. The maximum water flow is 6 gpm at full load. The old system used a star wheel feeder and a screw conveyor to move the hydrated lime. An upgraded system is deployed in the new system. A dense phase transport system will move the material into the venturi duct. Pulse jet bag houses are used in both systems. The ID fans will be upgraded and properly sized. Variable frequency drives are used.

The screw conveyors on the older system did not have enough capacity, causing some storage of flyash and lime in the hoppers, leading to plugging problems. The new system will have higher capacity with continuous operation to assure that no storage results in the hoppers. The storage bin will be increased in size for the new system. Load cells were installed on all hoppers to determine if any material is “hanging up” in the system. Each cell of the bag filter is monitored for emissions and bag leaks.

The boiler MACT standards for 0.07 lb/MMBTU particulates, 9 lb/trillion BTU mercury, total selected metals, and opacity were all met. An SSM plan is in place. The unit was ready to meet the September 13, 2007 compliance date for the MACT rules.

XVIII. A Technical Program to Enable Solid Fuel Flexibility in Industrial Boilers - Pat Mongoven, Fuel Tech

The University of Illinois has a power house that originated in the 1940s that supplies heat and electricity to the campus consisting of 3 gas boilers, 3 coal boilers, and 2 gas turbine combined cycles. The plant would like to burn more Illinois coal and less natural gas. The Illinois coal resulted in a lot of slagging problems in the stoker boilers. Options included burning a different coal, burning more gas, or solving the slagging problems. A test burn of Indiana coal was successful, but the local situation pressed for Illinois coal.

Fuel treatment used to be a wide area, or “carpet bombing” technique that would hopefully get the treatment chemical to the right place to be effective. CFD modeling allows for a more well-defined target area where the temperature is high enough to induce slagging problems. The modeling also helps show where the additive goes in the furnace. Different injection locations can be tested by models to see where the additive goes. Magnesium oxide can modify the ash formation so that the deposit is weakly structured and easy to remove. The initial application of the additive ran for 4 months and showed removal of the main deposits. There were still some deposits above the injection locations, which necessitated some adjustments to the nozzles to get the coverage that was desired.

The unit has been operating for almost a year since. Some testing has been done to reduce the amount of additive. They are estimating that the additive cost will be about $2.25/ton compared to the $10/ton premium for Indiana coal.

XIX. Dry Sorbent Injection for Emissions Control - Keith Day, O’Brien & Gere Engineers Inc.

Duct injection systems inject sorbent materials in the back end duct work to provide additional control of emissions. The Boiler MACT and various permit requirements include particulates, SO2, SO3, NOx, chlorides, and potentially CO2 (lower exit gas temperature). Economics are dependent on a wide range of coal fired boilers. For mercury, sorbents include activated carbon, halogenated carbon, and alternative absorbents. Enhanced removal includes trona and hydrated lime. SO_3 is thought to interfere with mercury capture.

Typical injection rates are 1 - 5 lb/MMACF of gas. System costs range from $250,000 to 750,000 for a 100 kpph unit. For HCl, trona and hydrated lime are used at 6 - 8 lb/MMACF. Costs are in the $500 K - $1 MM range. For SO_2, the typical sorbent is trona, although hydrated lime can be used. About 4 - 5 lbs of trona per pound of SO_2 is used. The system capital cost is $750 K - $1.5 MM. Sorbent cost in on the order of $600 - 1000/ton SO_2. For SO_3 control, trona and hydrated lime are used. The typical injection rate is 100 - 300 lb/hr. System capital costs range from $500 - $1MM. Operating costs are $10 - 30/hr. Additional collection of NO_x and mercury can be achieved. About 20% reduction in NO_x is often achieved and roughly 30 - 60% mercury removal can be achieved. Ash that has higher carbon content has the potential for higher mercury capture. The HCl is removed at high levels. Milling the trona can result in better utilization. Hydrated lime generally comes in quite fine. Design and installation times are typically less than 1 year. For dry systems, it is important to keep the material dry. Dry air is critical for transporting and conveying the materials.

XX. Sorbents for Today's Industrial Emission Control - Howard Fitzgerald, Chemical Lime Company

Chemical Lime is one of the largest lime companies in the world with 17 lime production plants in the US. They have established a flue gas treatment solutions team (FGT). Limestone is naturally occurring. When limestone is heated, CO_2 is liberated and calcium oxide (CaO) remains. The product is referred to as lime (or quick lime). When lime is reacted with water, some heat is liberated and calcium hydroxide is formed ($Ca(OH)_2$). This is called slaked lime or milk of lime when slurried. When exposed to air over periods of time, CO_2 is picked back up to form calcium carbonate ($CaCO_3$) or limestone.

As the cap on SO_2 emissions is ratcheted down, the industrial emissions as a percentage of the cap is increasing. Important criteria for industrial boilers are low capital costs, quick installation, small foot print, easy to operate, and easy to permit. Acid gas control includes SO_2, SO_3, HCl, HF, and mercury. Dry hydrate injection in the upper furnace can remove 20 - 60% of the SO_2 with high removals on HCl, HF, and SO_3. The capital cost for such a system was about half of a wet scrubber system.

Humidification of the flue gas was found necessary to help the ESP with the resistivity of the ash. With humidification to within 20 F of saturation, up to 70% removal can be achieved with some sorbent injection in the duct work. Advantages for SO_2 include relatively low capital cost, quick implementation, small footprint, easy O&M, and adapted for load following. Disadvantages include relatively low removals, some impacts on downstream equipment, moderate reagent utilization, and relatively higher cost consumables.

Lime slurry duct injection utilizes a slurry of lime (milk of lime) that is atomized in the gas stream. The water is evaporated in the gas stream. The original use was for industrial applications, particularly for cement plants, brick kilns, and other plants. Fairly high removals can be achieved with adequate Ca/S mole ratio. Duct design needs to consider good flow dis- tribution. Sufficient residence time is needed to absorb the SO_2 and dry the product. Gas velocities range from 20 - 80 ft/sec. The residence time ranges from 0.5 - 2.0 seconds. For SO_2 removal, about 1.4 lbs of calcium hydroxide is required for each pound of SO_2 to get 90% removal. SO_2 removal is improved with small droplets.

The quality of the hydrate is also an important factor for SO2 removal. Particle size is also important. The difference in surface area for the same mass using 50 micron particles and 3 micron particles is 7,500 mm2 to 132,000 mm2. The advantages are fairly high removal, low capital costs, quick implementation, small footprint, easy operation and adapted to load following. The disadvantage would be reagent utilization, higher cost of sorbent, and slurry handling.

XXI. Coal Processing for Emission Compliance – Rolando Sanz-Guerrero, CoalTek

Coal use is still predicted to provide a substantial portion of electric and steam generation. As emissions requirements get more strict, removing pollutants gets more and more important. CoalTek has developed and commercialized a treatment process that physically and chemically transforms the coal using microwave technology. The coal is treated in 3 modules (about 50ft each). The treated coal can be blended with parent coal or other coals to meet emissions standards. When coal is exposed to microwaves, the moisture in the coal is heated. The carbon is passive to microwaves. The water dissolves inorganic materials in warming up and heats up. Eventually the water evaporates, releasing some of the contaminants. The current facility is a 120,000 ton/hr production facility.

At the moment, they are selling the fuel. They are not selling the equipment to make the fuel. The fuel cost must be competitive. The steam produced from the microwave goes to a bag house. The particulate removal collects the contaminants. The resulting steam, if condensed, would be an agricultural grade water. The steam could be used locally (and is used at the plant) if there is a local steam demand.

XXII. Emission Control Strategy for Fuel Flexibility and Cost Reduction for Midwest Client's Coal Fired Boiler - John Foster, SP Environmental/Amerex

The Midwest application was a stoker with an existing pulse jet baghouse meeting SO2 permit of 1.0 lb/MMBTU with compliance coal. Steam conditions are 640 psig and 750F. Unit capacity is up to 320,000 lb/hr. Various systems were to be evaluated against a spray drier absorber. A new spray drier absorber with associated hydrated lime system, ductwork, ID fan, compressed air, ash storage, and controls was evaluated. An additional module to the baghouse was also required. A taller vessel than necessary was selected to allow for future regulations. The candidate coals would have higher sulfur and chloride levels than the existing compliance coal. Over 95% removal of HCl is attained in any case. A 50% gas treatment case was evaluated, but equipment cost was high relative to the 100% cases.

Natural gas was evaluated at $7/MMBTU. Pebble lime was $115/ton. Coal was $2.50/MMBTU. Natural gas was evaluated as an alternative to using coal. The gas case was nearly double the coal case with controls. Using the higher sulfur coal and firing some gas to meet the sulfur limit still compared unfavorably to the coal unit with controls. The capital cost estimate was about $10 million. The simple payback against gas firing is less than 1 year.

XXIII. CEMs Monitoring and Testing Panel - Bob Davis, Airgas, Moderator

The panel consisted of Louis Nichols of EPA, Larry Fisher of Ashtead Technology Rentals, Robert Mueller of Airgas, and Daniel Todd of Air Quality Services, LLC.

<u>Louis Nichols</u> reviewed the EPA Option to "Opt In" to the Clean Air Interstate Rule. This falls under the Clean Air Markets Division of EPA. This division of EPA prefers trading to other forms of control. In order to opt in, the unit must be in a CAIR state. The unit must not be a CAIR affected unit. The unit must not be a retired unit. Finally, the unit may not be an Acid Rain opt in unit for SO2.

The idea is that allowances can be generated by a unit that might conceivably reduce emissions at a lower cost than a CAIR affected unit. There is an annual NOx trading program, an annual SO2 trading program, and an ozone season NOx trading program. The state must be in one of these programs to opt in. For example, Massachusetts and Connecticut are only in the ozone season NOx program. Units in those states cannot opt in for SO2.

The model rules are in parts 96 or 97. The unit must be a unit that can be monitored under part 75. There are two approaches that units can choose from. The general approach requires a minimum of 30% reduction from baseline. No additional reductions are required beyond 2010. Units may opt in for one or both pollutants. Units may opt in for different pollutants at different times. The unit may withdraw after 5 years. The baseline is the average of the most recent 3 year period of part 75 monitored data (or less if not monitored). Allowances will be generated for emissions levels below 70% of the baseline.

The alternative approach is to repower to one of the technologies listed in the rule (including CFB and IGCC). No reductions are required during 2010 - 2014. Deeper reductions are required after 2015. In this case, the unit is essentially in forever. In this case, allowances are generated at baseline levels through 2014. After 2015, the baseline heat input is used with the 0.15 MMBTU for NOx or 90% removal for SO2. NSR is not impacted by these rules. Thus, a repowering would still go through NSR. There is also not shield from BART for opt in units. SO2 credits under Title IV are worth 1 ton of SO2 until 2010. These credits issued after 2010 will be worth 0.5 ton. The CAIR credits are worth 0.5 ton and start in 2010.

<u>Larry Fisher</u> reported on living with the new Part 60 test methods. Protocol gases were also covered. Changes were effective August 16, 2006 and were intended to update the testing methods from the 70s and to harmonize the various approached. The new tests allow the tester to choose a high span (20 - 100% of expected concentration). This will allow the use of Zero gas for the low span calibration. Method 7e for NOx is the primary instrumentation test replacing 6c. The interference check is now more complicated. However, once the instrument has passed the test it is accepted unless there is a substantial change.

Tips to be aware of before the next RATA. If the unit is under Method 20, one can ask the state to use Method 7e. The interference check is for instruments after August, 2006. Older instruments can show the older check. Verify that the stack tester has tested the analyzers for stability and interference. Some NOx analyzers require an NO2 converter efficiency check before each test. A calibration gas with 20 - 40 ppm NO2 will be needed. The Zero calilbration gas is defined under 40 CFR 72.2. By choosing the span range carefully, the span can be used for Part 60 as well as Part 75. For calibration gases, it is important to check the expiration dates on the calibration gases. An expired cylinder will have to be re-certified (pressures below 500 psi will not be re-certified).

Part 75 will require protocol gases from vendors that participate in the protocol gas verification program. Use stainless steel lines for sampling to avoid problems with SO2. Make sure auditors use the same CO2/NOx concentrations as the tester. CO2 concentration can impact the NOx readings. Outdoor cylinders are subject to stratification, particularly for CO2 and mercury. When changing out the low NOx protocol gas use caution. Oxygen can go back into the cylinder if the line is not purged properly. When running low on gases, know the compliant range rather than the specific ppm level. This may help locate a gas that can be used as opposed to the exact ppm level. In bidding for stack testing, plan to buy the gases yourself. Get an explanation for rental charges. Gas suppliers own the cylinders but the owner owns the gases.

Bob Mueller reported on ammonia awareness and safety. Ammonia is a combination of liquefied air and hydrogen. The body produces small amounts of ammonia every day. The largest use of ammonia is for fertilizer. In large quantities, ammonia is not healthful. It has a strong smell to serve as a warning. At 5 ppm, ammonia is detectable by smell. At 50 ppm, it can be harmful for long term exposure. At 300 ppm there is immediate danger. At 5000 ppm it can be lethal.

Anhydrous ammonia has no water. It is a pungent, colorless gas that is normally stored as a liquid under pressure. The pressure varies greatly with temperature. Ammonia has a very strong affinity for water. One gallon of water will absorb 1300 gallons of ammonia. This is bad because our bodies have areas of considerable water (eyes, nose, mouth, sweat, etc.). On the other hand, water easily flushes ammonia. Thus, flushing with copious amounts of water for 15 minutes is recommended. For inhalation, move the person out of the area. Wear protective equipment to avoid double exposure. Get medical help immediately. For ingestion, drink water (or milk).

An MSDS sheet should be on site. This sheet contains all the information about storing, handling, and treating the material in question. Personal protective equipment includes rubber gloves, eye goggles, and long sleeve shirts. A face shield is also recommended (not a substitute for goggles). Emergency showers and eye wash stations are necessary. Respirators should be used for escape or minor release. Self Contained Breathing Apparatus should only be used by trained emergency responders. Storage tanks should not be filled more than 87.5%. Ensure that a hydrostatic relief valve wherever liquid can be closed between two points in piping. Trapped liquid can vaporize and cause a pipe failure (needed for any liquified gas).

Ammonia systems should be stainless steel, Monel, or aluminum. Copper or brass should never be used with ammonia. Always position yourself upwind from any potential release. Ammonia vapor is lighter than air and will rise when released. The gas is colorless and may not be seen. Smell is the most immediate indication of a release.

An emergency response plan is required for every site which falls under the EPA's risk management plant requirements. The environmental health and safety personnel should have all of the rules, regulations, and risk management plans for the system that is being used. Power plants should have fixed detection systems with alarms are appropriate levels.

Dan Todd reported on how to get ready for a stack test. It is important to keep in mind the "who, what, when, where, and why". With regard to the reason for testing, there are compliance tests, performance test, calibration or audit tests, and data generation tests. On the what, it is important to identify and develop the scope of work. There should be a site visit to identify the test location and clarify the safety concerns and issues.

For a compliance test, there should be a pre-test meeting with the Agency. The Agency has to be formally notified of the test. The testing must be defined. The test parameters, the pollutants to be measured, any process data, and the test methods all have to be identified. Post test activities should focus on the report. Specific units should be identified (i.e. lb/hr, lb/MMBTU, ppm, etc.). The need for preliminary results should be identified. The draft schedule should be set up. The timetable and submittal responsibility needs to be defined. The test schedule (or the when) needs to factor in the notification requirements, the plant requirements, and any process time constraints. The bid process takes time. Particular arrangements such as soot blowing during the test need to be communicated to the operations staff. Finally the report submittal timetable needs to be agreed upon. Rush schedules typically cost more.

The tester responsibilities include the equipment, personnel, safety requirements, and insurance requirements. The source responsibilities include access, contact, power, and safety requirements. The testing location should be such as to allow for appropriate ports, probes, access, weather protection, etc. The gas conditions should be identified (temperature, pressure, and flow). Prior test conditions would be helpful for the tester along with expected results. There might be some advantages to having a preliminary test to do diagnostics. Contingency days might be considered in the schedule for a complicated test. When in doubt, ask questions. A check-list might be helpful.