CIBO Industrial Emissions Conference
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Portland, Maine

I. Boiler Compliance Workshop & Working Lunch - Bob Fraser, ERM

CIBO is one of the best forums to share experiences and learn from colleague's "lessons learned". Bob Fraser will handle permitting and air pollution control. Teresa Raine will talk about air dispersion modeling. Peter Anderson will handle compliance auditing issues. One example was the permitting of a gas fired boiler. The facility originally had coal fired boilers. One boiler was converted to coal in 2001 and was intended to handle peaks. The unit now has been base loaded since 2010. The other boiler was a coal fired, spreader stoker of 500 MMBTU/hr. An ESP was aded in 1968. The unit has an NSR issue due to a fuel change (to a lower sulfur fuel). The unit does not meet the proposed MACT standards. MACT compliance was estimated to cost $60 million. The price of gas has been sufficiently low that the plant sought to convert to a gas fired boiler with higher steam conditions such that co-generation might be possible. The plant went to EPA and offered to convert to gas as a settlement for the issues with the coal fired boiler. It appeared that this was the direction required by everyone. However, EPA stated that no credits for emissions reductions would be available from shutting down the old coal fired boiler, because the old unit was considered to be "not in compliance". The state agreed to expedite their permit. The Board of Directors approved the capital appropriation for the new boiler. In the interim, the plant looked at renting some gas fired boilers to provide steam and electric. In looking at the emissions profile for these boilers, the new GHG rules triggered the PSD requirements for the boiler. Once that PSD was triggered, PSD also came into play for NOx (LAER), PM10 and PM2.5 (due to oil back up), and SO2 (again due to oil back up). The state indicated that some modeling would be required and that it would be desirable to get below the SIL levels that start to trigger additional work. A plant worker's son (video gamer) downloaded AERSCREEN and ran the model. The results were 500 times the SIL for the 1 hour NOx and 300 times the SIL for the 1 hour SO2.. The state indicated that if the unit could not get below the SILs, the plant would have to submit a protocol to include surrounding plants in their analysis. The rental boiler company does not have any boilers with ultra low NOx burners (9 ppm). New boilers can be purchased for delivery in 2015. One rental company has rental units with SCR installed in the stack that can meet the 9 ppm limit (LAER). One problem is the capex/opex is not sufficient to cover the SCR. BACT for SO2 is 15 ppm. BACT for GHG should include economizers. The rental boilers do not come with economizers. Taller stacks might help. The plan was to go to 5 x 100 MMBTU/hr gas fired boilers, which would require 5 new, taller stacks. With 9 ppm gas, less than 330 hr/yr on ultra low sulfur oil, the plant can avoid PSD for NOx and SO2. Economizers will pay for themselves and contribute to BACT for GHGs. At this point, the plan was to go to 2 x 250 MMBTU/hr gas fired boilers with ultra low sulfur oil with taller stacks. The only problem is that temporary boiler are only allowed to be on site for 6 months. This time frame will not meet the schedule and will have a gap for which there would be no permit. Additional modeling indicated that 5 stacks of 300 ft each will be needed to predict impacts that are below the SILs. Now town variances are needed once the stack height exceeds 199 ft. Also lighting and FAA approval will be needed due to the proximity of the municipal airport. If oil back up can be eliminated, the stack height can be reduced to 125 ft. With this in mind, the oil back up was eliminated for the rental boilers. This allowed the plant to get permits for the rental boilers for 18 months. For the new units, full AERMOD simulations had to be run. The two permanent boilers were allowed to have oil back up since these units did not have to get below the SIL levels. The take aways from this little project are as follows:

- it is always better to net out of PSD review
- plan on BACT level of control for NOx and SO2
- GHG BACT is triggered by a potential 75,000 ton/yr increase in CO2
- State permits for rental boilers vary and need to be checked
- Rental boilers are limited to what is available
- Very few projects will model under the SIL for 1 hour NAAQS
- Backup oil emissions will drive the modeling
- Plan on running AERMOD, multi source modeling
- Allow 6 - 12 months for permitting (even for gas firing)

Teresa (“Tree”) Raine reported on the short term NAAQS issues associated with modeling and permitting. The problems are getting worse. The Clean Air Act requires EPA to establish these standards that are protective of health and welfare with a margin of safety. Cost cannot be considered in the setting of these standards. The current NAAQS are 75 ppb for SO2 for 1 hour, 100 ppb for NO2 for 1 hour, and 35 microgram/m3 for 24 hours. The Significant Impact Levels (SILs) are 3 ppb for SO2, 4 ppb for NO2, and 1.2 microgram/m3 for PM2.5. These standards are very low. Recent experience has shown that modeling for permits have become increasingly complex. Public interest groups are using NAAQS issues as instruments for stalling projects and permits. Environmental groups have their own modeling experts. Guidance and models are still evolving as the models were never designed for one hour standards. Controls required for meeting the NAAQS could exceed the control based standards for BACT or MACT. The standards are low and the background concentrations are now known to be higher. Modelling challenges include multi source analyses, ammunition for public interest groups, and the actual models themselves. EPA initially required modeling for attainment designations. They are now taking a step back (combined modeling and monitoring). States are waiting on EPA guidance for attainment and SIP development. States have also complained that they do not have the budget for additional monitors. That will likely mean that projects will incur the cost of adding a monitor. Sources that are greater than 1000 ton/yr of SO2 are likely to require a monitor nearby. For NO2, the non-default modeling options are required for many projects. Emissions include NO and NO2. The ratio of NO to NO2 makes a difference in the models. EPA acceptance will have to be gained to use the non-default options. Designations will be based on expanding the monitoring network. The SIL values are very low and it is difficult to get below the threshold, even with well controlled, natural gas boilers. The PM2.5 emissions are contributed by primary sources (combustion, material handling, fugitives) and secondary sources (formed from SO2 and NOx in the atmosphere). There is a proposal to tighten the PM2.5 standard further. There is also consideration of visibility and urban locations. For non-attainment areas, SIPs developed by the states are required. These must be approved by EPA. AERMOD issues include low wind speeds, downwash, and the NO/NO2 ratio. The conservative nature of the 1 hour guidance led in part to re-consideration of the designation approach. EPA has issued a white paper proposing a new monitoring approach and comments have been solicited. The majority support monitoring except for environmental groups and some states (budget issues). As an example, one boiler in New England was a 500 MMBTU/hr boiler with level terrain and little complexity. The very low SIL means that it is easy to exceed the SIL, even using 98% averaging. This source had a 200 ft stack but still had SIL issues about 2 km from the plant. This project did not require PSD permitting. For PSD, the 98% averaging can't be used. This made all locations above the SIL. This plant had 9 ppm NOx burners and no oil back up. Modeling is now driving the permit process. Talking to state regulators is a necessity to get the ground rules. Existing sources will not likely show modeled compliance.

Peter Anderson reported on performance and assurance. Once the plant has a permit, the plant has to operate within the permit limitations. The plant does not want to be in a situation where a notice of violation (and subsequent fines) has been issued. US Environmental Regulations have grown to 24,000 pages in 2010. The performance expectation has increased over time. In the past, a test was performed and a compliance program was put in place to resolve any problems. Now accountability and sustainability have become part of the requirements. A multi step approach is required to address these issues. First, the stakeholders need to be identified along with there needs and requirements. The purpose of the audit program should be identified including all regulations, company standards, risk identification/mitigation, effectiveness, and actual improvement (how to monitor and measure). The scope of the audit needs to be established. The audit can be internal to the organization, but may be under the direction of an outside counsel (so that results are covered under attorney/client privilege). A self disclosure audit policy can be established in accordance with EPA and state requirements. The primary emphasis should be established (ie safety, contamination, sustainability, carbon footprint, etc.). The tools and techniques to be used need to be identified. Root cause analysis should be conducted. The audit team (both internal and external) needs to be identified. Sometimes specialists are needed. The outcomes of the audit should be established. The type of report and contents need to be agreed upon. Audits should have a focus of interest in the organization's exposure. There have been notable failures of high impact exposures at companies that had substantial audit programs. If the audit is just an exercise, nothing will really happen. Auditors will never be able to identify all risk conditions and behaviors. Identifying root causes is key to determining the factors that underpin performance achievement.

II. EPA Database Evaluation for Compliance - Amy Marshall, URS

Amy reviewed the background on the Industrial Boiler MACT rule. A proposed reconsideration rule was issued in December, 2011 with no dioxin/furan limits. However, the stay of the March rule was vacated by the courts so the March version of the rule is theoretically on the books. As a result of information requests that were issued by EPA, a boiler MACT database has been made and updated. The last update was in May. CIBO used the EPA database to develop industry compliance costs. EPA is still looking for CO CEMS data. Industry has been advocating a work practice standard (similar to the Utility MATS rule) for CO, particularly for coal fired units. The number of units in the database is 1742 of which 607 are coal and 481 are biomass. There are no units less than 10 MMBTU/hr, or fire gas, or are limited use units. The data is being used to evaluate the lowest 12% of units that have stack test data. The average of the lowest 12% is used to set the MACT standard. A 99% upper prediction limit is calculated from the run by run stack test data for the top performers. Variability is supposed to be taken into account. With this approach, no particular control technology is attributed. From the EPA database, each site was evaluated for existing emissions and control equipment were present. Base capital costs were established for PM, HCl, Hg, and CO equipment. For each site, the need for one of these technologies was determined.   Costs can be subtotaled by state, industry sector, fuel type, etc. In the current proposal, there are a number of categories and subcategories. Biomass boilers have been segregated into 9 subcategories. In this case, all subcategories are better than 6% compliance. For coal fired plants, there are 4 subcategoires. Stokers only have 2.6% of units that can comply. For oil fired units, only 1.2% of heavy oil units can comply and none of the light oil units can comply. Through the comment process, work practices for natural gas, limited use, start up/shutdown/malfunction (SSM), and dioxin/furan. The remaining issues on Boiler MACT include compliance time, costliness of the rule, flexibility in emissions averaging, better provisions for SSM, better definition of gas curtailment, and more monitoring flexibility. EPA combined solid fuel boilers into one subcategory. This provides consideration for multi fuel boilers. However, there appears to be considerable variation in Cl and Hg content particularly between biomass and coal. A fuel variability factor has been suggested by industry. EPA used an "outlier approach" to obtain a fuel variability of 1.67 for Hg and 1.91 of HCl. The possible "final rule" for Hg and HCl is 5.7 lb/TBTU and 0.021 lb/MMBTU for existing units. The HCl limit did not change much. The mercury increased slightly as 3 more units were added to the floor calculation. For new units, it looks like all the levels will be slightly tighter. It does look like biomass units will mostly meet the re-proposed standards. For coal and oil units, control equipment will likely be required, unless the units switch to gas. However, it does look like the use of the fuel variability factor will help 87 - 89% of the stoker and pulverized coal units. The fluid bed units typically will not need to add additional controls. Interestingly, due to the volatility of mercury, there is a higher mercury concentration in light oil than in heavy oil. Oil fired units will likely need mercury controls. The CO limits are problematical. The estimated costs for CO2 reduction are likely to be several billion dollars. EPA elected to use CO as a surrogate for organic HAPs. At CO concentrations above about 100 ppm. there does appear to be a reasonable correlation for organic HAPs with CO. However, below 100 ppm, the data indicates that there is no significant correlation between organic HAPs and CO (ie the organic HAP emissions are relatively constant over the range of CO concentrations between 10 and 100 ppm. This is likely due to a change in mechanism for the destruction of organics. The total cost estimate for Boiler MACT is currently estimated at about $13 billion. The revised rules are still very costly. Few units in the fossil subcategory comply with all 4 limits. Emissions averaging is not allowed between subcategories, but, if allowed, may reduce costs. Mercury limits have significantly improved with the fuel variability factor. The CO costs will also improve with a work practice standard.

III. Informal Equipment Suppliers "Shirt Sleeve" Session - Norb Wright

In response to a question about combined chloride and particulate collection, the likelihood would be that a new bag house would be required to meet the particulate standard (perhaps half of the coal fired units). The new bag house will need to be sized to account for the additives that will need to be injected to control the chloride, mercury, and NOx that will be required to meet those standards. A new fan will probably be needed to handle the additional air for CO control. The bag house will need to take this into account as well. At some point, the electrical equipment may be impacted as well. The plant owner will likely have to establish a fuel strategy because the performance of the unit will be dependent upon the fuel. It was pointed out that some owners are asking for emission rates that are lower than the proposed EPA figures in order to have some leeway in meeting the standard. The suppliers also look at the standard with an idea to allow for some cushion in meeting their guarantee. Another alternative could be a "make or buy" strategy. Last year, a number of owners did not have emissions data for their units. It would be interesting to know if that has changed significantly. The other question is one of industry capacity, particularly if both utility and industrial units fall on the same compliance schedule. The combination of permitting requirements and timing of the two rules will determine the difficulty of finding resources for all of these activities. The smaller companies are going to have difficulty complying with these standards. Although each case is site specific, there are likely to be a number of units that will elect to switch to gas, either through conversion or through new gas fired units. Another unusual idea would be to contract out the treatment of the gases for air emissions.

IV. Review of Concurrent Forum Sessions - Ann McIver, Citizens Thermal

Carl Bozzuto reviewed the Equipment Supplier session. The bottom line was that each unit is in a site specific situation. A risk strategy is needed, which will likely include a fuel strategy. Roughly half of the coal fired units cannot meet the existing plant particulate standard. These units would likely need a new bag house to meet the standard. The bag house will have to take into account the additives that might be required for chlorides, mercury, and NOx. A multi pollutant strategy needs to be contemplated. Make vs. buy decisions about power and steam are likely. Contracting out the emissions controls could be a future option. Again, each situation is unique and site specific.

Ann McInver reported on the Owner's Session. One of the issues for owner's is the measurement and testing of units. The reliability of and repeatability of testing and measuring each of these compounds at the levels that are being contemplated. Having good stack testers that are reliable is critical to getting good numbers that can be relied upon for meeting the standards. Also, besides the equipment and installation cost, the unit has to get started up, lined out, and tested before being declared commercial. That additional cost needs to be realistically assessed. There are other regulatory and compliance issues that impact facilities including water issues and other wastes. Fuel issues include the current pricing in the market for both coal and gas. LNG export could become the competing fuel price for gas. Understanding the options, particularly for those that might be able to meet the proposed standards should be part of the strategy. There are always some things that happen that are out of our control. Figuring out what can be considered back up requirements (emergency, insurance requirements, curtailment) can also be a challenge.

V. Environmental Rules, Regulations, and Implementation for Industrials - Panel

Bob Fraser reported on the EPA's Boiler and Air Toxic rules. For the Industrial Sector, the rule that was supposed to be issued on June 15th, has not been issued. At this point, our expectation is that now the rule will be issued after the election. The 3 year clock may or may not be reset. Litigation is anticipated by everyone. Political changes may impact the final details. This has led to another year of uncertainty while companies are being squeezed due to the economy and the potential regulatory impacts. The courts have not been particularly helpful and have pushed the rules toward numerical data manipulation. The idea that this standard is about health impacts is very misleading. The MACT limits favor preservation of older boilers vs building new ones. The same amount of HAPs from one type of boiler are not more dangerous than the same amount of HAPs from another type of boiler. The technology driver is no longer based on what is "available". For the Utility rule, it no longer matters if you are a major source or not, you are subject to the MACT rules. It is now possible to move in and out of categories and subcategories. The units for limits are not consistent. The plethora of rules is more like a roller coaster ride than a train wreck. There is a rule for every boiler, except Qualified Facilities. The political issue of coal can be compared to the municipal solid waste rules (MSW units). In the 80s, the EPA essentially stopped the construction of new MSW plants in the US. Assume for a moment that we have a multi capable boiler. This could be a stoker boiler with pulverized fuel capability above the grate. The capacity is 249 - 251 MMBTU/hr depending on the fuel moisture. The unit can burn coal, biomass, pet coke, and/or MSW. Depending upon how the unit is run, the boiler could be categorized was a utility unit, an industrial boiler, an MSW unit, or a waste incinerator. If the standards for these units are all put on a common basis, there is a wide variation in the figures. In the case of mercury, the municipal waste units have a limit that is 10 times higher than boilers. Even the boiler limits vary by a factor of 10 between existing coal and new coal. Compliance strategies could include QF status (exempt), Area Source (GACT), conversion to gas, co-fire gas, sell electricity (MATS), uprate to 250 MMBTU/hr, derate to under 250 MMBTU/hr, switch sub categories to average with coal units, opt in to MATS, burn 70% RDF (MSW), convert to biomass, or add 1 lb/yr of carpet scraps (CISWI). In the meantime, we still need to be working diligently towards compliance with the Industrial Boiler MACT rule. During this period of uncertainty, we need to prepare some contingency plans. There are potentially a lot of options to consider.

Andy Bodnarik, now of the Ozone Transport Commission (OTC) reported on their Stationary and Area Source activities. The CAA of 1990 created the OTC to advise EPA on the ozone transport issue, including mitigation strategy. It includes all the New England and mid-Altantic states. The group models air quality in the region to develop model rules on the types of reductions that could lead to NAAQS compliance. They also consult with EPA. Activities include research and data collection, economic analysis, stake holder outreach, collaboration with other states, update and revise adopted measures, analyze EPA proposals, identify new solutions, and discuss various approaches. For consumer products, paint thinners and solvents were put into a model rule in June 2011. After taking stakeholder input, a final rule was issued in March 2012. A similar rule was issued for solvent degreasing. These rules are anticipated to reduce organic emissions by hundreds of tons per day. Natural gas compressor pipelines are another source of organics as well as GHGs. A draft model rule was developed in November 2011. Energy efficiency strategies have focused on commercial buildings. This initiative has the potential to reduce NOx emissions by 100 ton/day. This approach had an estimated payback of 2 - 4 years. A draft report has been released. MSW units were delayed in anticipation of Boiler MACT. Coal Fired boilers serving EGUs now come under CSAPR, which is intended to replace the Clean Air Transport Rule. Litigation is under way on this rule. Vapor control from gas stations is being looked at. A study is being done by the state of CT. Data is being gathered. At the May meeting, ozone transport was still the top priority. Coal fired EGUs, industrial units, and organic emissions are being looked at for reductions. Demand response is now being considered to evaluate its potential for reductions. The RICE MACT rules were commented on for use in demand response. The concern was that an engine could run for 50 hours rather than 15 for demand response. As these units have no controls, the Nox emissions from such units will increase.

Marc Cone of the State of Maine reported on licensing and permitting in the State. The PM2.5 NAAQS were issued as a final rule in May 2011. This rule repealed the "grandfathering provision" that is contained in the PSD permitting program. All states had until May 2011 to modify their SIPs. However, in June 2012 changes were proposed. The annual standard would go from 15 micrograms/ m3 to 12 - 13. The Class II and Class I increments were 4 micrograms/m3 and 1 microgram/m3. The rule is supposed to be finalized this year. For PM2.5, it is difficult to make measurements in very small units. Major New Source Review (PSD) is trigger at 10 ton/yr of PM2.5. The new ozone standard was anticipated for August 2010. In July 2011, a new standard was proposed. Then, earlier this year, the old standard was maintained and the new standard was put off until 2013. The SO2 and NO2 NAAQS were reduced to 75 ppb and 100 ppb respectively. EPA wanted modeling analyses for permits to meet these standards. The trigger level was 100 ton/yr. EPA is considering changing that upwards to 1,000 or 2,000 ton/yr. The 1 hour standard will drive the SO2 permits. Small, #2 oil fired boilers will have to model, especially if stacks are short. For the NO2 standard, the ratio of NO to NO2 in the exhaust stream becomes significant in the modeling. The first tier assumes 100% NO2. The second tier assumes 80% of NO is converted to NO2. The tier 3 method assumes that ozone is the limiting mechanism estimates the amount of NO that is converted to NO2. Some states are requiring engines to model for NO2. The SIL for the Northeast is 10 micrograms/m3. For internal combustion engines (ICE), there are MACT rules for reciprocating engines, spark ignition engines, and compression ignition engines. The criteria compounds for NSPS are NOx, CO, VOC, and PM. The RICE MACT rules apply to all sizes of engines. The only exemptions are existing emergency engines at certain facilities (hospitals, schools, fire stations, etc.). There are stationary vs mobile engines. Under mobile engines for non road use (mining, lawn mower, etc.). For new RICE units there are NSPS. The compression ignition engines (diesels), there record keeping and monitoring requirements. There are similar rules for spark ignition (gasoline engines), including record keeping and testing. Emergency units are not limited on total hours of operation. However, there is a limit for testing, start up, and certain other types of operation (demand response). Engines used in response to a financial request are not considered emergency. The allowance for peak shaving would end on April 16, 2017. For Area Source MACT, EPA issued a "No Action" letter, indicating that they would not attempt to enforce the Area Source rules while the other MACT rules were being "reconsidered".

Kevin Dougherty of Fuel Tech reported on SNCR and I-NOx systems for Industrial Boilers. Furnace modeling is used to estimate performance of furnace additives that can improve emissions or improve performance. Cold flow model facilities can also be created for validation testing. Injection of urea or ammonia (SNCR) in the optimal temperature window (1600 - 220 F) can reduce NOx by 25 - 50% in utility boilers and 30 - 70% in industrial boilers. For SNCR, furnace modeling for flow fields, chemical kinetics, and injection is used to predict performance. Droplet size can be varied to provide different penetration rates in the boilers. For one papermill plant expansion, the steam flow rate was 550,000 lb/hr with a variety of fuels. The NOx reduction was 50%. The ammonia slip was 25 ppm. Two levels of introduction were used to allow for load changes down to 30%. SNCR can be integrated with low NOx burners and SCRs in order to optimize the overall performance of the systems. With the potential reductions in CO that will be required, low NOx burners may have some limitations in pushing the NOx reductions. With the possibility of somewhat higher excess air levels for CO, the base NOx level will increase. Additional post combustion control for NOx reductions will be needed. SNCR can be optimized for reductions while allowing more ammonia slip. The SCR system at the back end will make use of the ammonia slip over the catalyst for further reductions and elimination of the slip. Looking at all of the steps, the burners, OFA, and SNCR can be designed for 30% reduction with the SCR at 45% reduction. The total reduction will be 81% without pushing any of the systems too hard. For a steel mill application firing coal and coke oven gas, the emission level was 50 ppm NOx with ammonia slip at 8 ppm. The catalyst life guarantee was 16,000 hours. A single layer of catalyst was used.

Bob Iwanchuk of AECOM reiterated the issue of the train wreck. In addition to MACT, there are NAAQS, GHG, Regional Haze, and CSAPR rules. On the NAAQS, the Clean Air Act requires EPA to review the science every 5 years for the 6 criteria pollutants. The current ozone standard is on a restart for the Bush era standard. Non attainment area designations were assigned in May 2012. EPA is currently working on a separate review that is due in 2014, with the likely result of a reduction to 70 ppb. The current non-attainment areas are mostly California and the Washington to Boston corridor. With a 70 ppb standard, the number of counties in non-attainment would increase by 515 counties. The new SO2 standard is now a one hour 75 ppb standard and is 7 times more stringent. Both modeling and monitoring will be requiring. In July, the DC Court of Appeals rejected petitioners' challenges to the 1 hour standard. The latest draft guidance from EPA seems to be backing off the modeling requirement for unclassifiable areas in State SIPs. The non attainment SIPs are due by February 2014. The attainment date is August 2017. The PM2.5 standard is 15 micrograms/m3 with a proposal to reduce this to 12 - 13. There is a proposal to adopt a new secondary PM1.5 visibility index for urban areas. A final rule is due out in December 2012. Once the rule is finalized, non attainment designations are due in 2015 and attainment is due in 2020. The NO2 standard was also converted to a 1 hour standard at 100 ppb. Interestingly, there were no non-attainment areas for NO2. EPA is planning a new monitoring network to attempt to find NO2 "hot spots". Then redesignations would occur 2016 - 2017. Greenhouse Gases (GHGs) are currently part of the permitting process (Title V and New Source Review (NSR)). New sources at 100,000 ton/yr CO2e and modified units at 75,000 ton/yr CO2e need to consider GHG emissions for permits. These are subject to BACT requirements. The DC Court of Appeals upheld the Tailoring Rule and the Endangerment Finding on June 26, 2012. In July, the EPA issued a 3 year deferral from application of PSD and Title V permits for biomass units. They also decided not to lower the threshold. In April, an NSPS rule for new utility units was issued at 1000 lb CO2/Mwhr generated on a gross basis. New coal (or petcoke) units would be expected to go for 50% capture and storage. There is an option to average over 30 years. The installation of new control equipment on an existing units is exempt from the 75,000 ton/yr threshold. Simple cycle gas turbines are exempt. The Regional Haze rule has now triggered the first “once per decade” reviews on the impact on visibility in pristine areas (such as National Parks). This first review targets Best Available Retrofit Technology (BART). On the Cross State Air Pollution Rule (CSAPR) (called “Casper”). The Court stayed the rule in December, 2011 leaving the CAIR rule in place. An Appeals Court decision is expected soon. The rule is restricted to EGUs only. There are no opt in provisions. The rule is intended to address upwind states’ emissions causing violations in downwind states. There will likely be a second round that will target more types of sources including industrial boilers. One of the reasons for this is that roughly half the emissions in question come from mobile sources. Mobile sources can only be regulated by a federal program (except for California).

Jason Philpot of Eastman Chemical reported on an industrial perspective. Eastman employs over 6600 in the Tennessee area along with 2800 contract employees and 6600 retirees. There are 4 power houses with 17 boilers and 19 turbine generators. They are similar in size to a 500 Mw power plant. They generate all of their steam and about 90% of the electric requirements with no export to the grid. Currently the gas fired units are in reserve. There are 3 stacks that need permits. For each regulation, the 3 different power houses have to prepare a compliance plan. As BART came first, a plan was put in place to come into compliance. Then MACT came along and additional controls were required. With CISWI, the waste materials that are burned have to be considered. Then the NAAQS revisions arrived, with additional requirements. There are interactions amongst these rules. For example, reducing SO2 for BART will likely reduce HCl for MACT. For each of the boilers, a rule chart was created which would identify the rules and requirements for each unit. For the newest units, control equipment already exists. This equipment should meet the MACT rules. However, the secondary materials would put some units under CISWI. The pros and cons of continuing to burn these materials have to be compared to the rule requirements for CISWI as opposed to other disposal costs. For the older plant, only ESPs are available for controls. Both CISWI and MACT require significant upgrades (and cost). The plant that just burns coal has the Regional Haze requirements. For these units BART will require SDA technology. This will help with the HCl and Mercury. Natural gas could also be considered. A number of combinations and permutations were looked at including new gas boilers and conversion of existing boilers. The first study amongst gas options looked like converting units to gas was the least cost option. This would be compared to remaining on coal. Cost curves were developed for coal and gas. The two curves were close. In the long run, the coal option would have a lower cost. In the short run, the coal option requires more capital. Reliability is a critical issue. Also, units converted to gas cannot be averaged with other coal units on the site. Units with scrubbers added can be averaged with other coal fired units. Units converted to gas face a tighter time line. In the long term, the gas option has higher cost and there is a risk of gas price forecast in the future. Regulations are written independent of each other. Implementation requires a “big picture” view. The most cost effective approach considering all regulations and all other impacts needs to be assessed.

VI. Particulate and Multi Emissions Control Technologies

Byron Nichols of Virginia Tech reported on back end emissions control systems at their plant. The plant is a co-generation facility with 440,000 lb/hr steam flow. The primary fuel is coal with the capability of burning natural gas and oil. The back pressure turbine is 6.5 Mw. The coal is 13,250 BTU/lb with 1.2% S and about 8% ash.   There are a total of 5 boilers. There are two Solios back end systems on the chain grate stoker fired boilers. The original installation was in 1996 and was BACT at the time. Primary parameters for the unit for the unit were SO2 collection and opacity. The second system was installed on the older coal boiler in 2006. Primary parameters were particulate emissions and fresh reagent feed. The goal was to meet the new MACT standards of 2004. Prior experience with the first system allowed for improvements to the second system. The overall silhouette was reduced for the second system with a relatively tight fit for the existing space. The system takes material from the baghouse and conditions it for injection into a venturi in the flue gas duct work. A tall duct is used for contact of the reagent with the flue gas. The gas then enters the bag house for collection. A portion is collected for recycle and conditioning (with water) and the rest is collected for disposal. Fresh lime feed is injected into the conditioning system. Enhancements include improvements to the feed of the conditioning drum. Inside the drum is a spray tube that sprays 6 gpm from 6 nozzles inside the drum. The first drum lasted 13 years before replacement. SO2 removal of 92% was required. The flow stream temperature is the key to performance. The flow duct temperature of 260 F - 280 F appeared to be optimum. Additional contact time is provided by having the gas turn around at the top and come down again. Performance has been very good. At this time, the chloride, mercury, and particulate levels appear to meet the proposed MACT rules. The SO2 capture is routinely higher than 99.5%. They need to stay in the range of 94 - 96% in order to average out to better than 92% during upsets. Performance monitoring for the bag house looks at the pressure drop in the various compartments and rows. This helps locate a bag with a leak. Bag house CEM systems do add to the complexity of the system. There is a particulate monitor on the new system and an opacity monitor on the old system.   The operator is the key person for the plant. Training is critical for continuous good performance. One key is to make sure little problems don't become big problems. Lime feeding is a key to good operation. Lime flow needs to be more or less continuous. Changes were made to the feed system to keep the lime flowing.

Yuval Davidor of Lextran, Ltd reported on simultaneous removal of NOx and SO2.   The goal was to develop a liquid control system for multi emission control. Wet scrubbers are used for SO2, but NOx is over a solid catalyst and mercury is with a dry powder. The wet scrubber can be augmented by using an oxidant (like hydrogen peroxide) to oxidize the absorbed gases to sulfates and nitrates. The scrubber solution can be ammonium hydroxide or potassium hydroxide. A catalyst is used to assist the capture and oxidation. Any solids are decanted and separated. The remaining solution is a sulfate/nitrate solution that can be used as a fertilizer. A number of units in the 20 -25 Mw size range have been installed. A 300 Mw unit has been installed in China. NOx reductions reduction levels of 65 - 70% have been achieved with peroxide. With ozone, over 90% reduction can be achieved. The system only needs 3 additional tanks besides the scrubber. Because the boilers are relatively small, the production of a fertilizer product can typically used locally without swamping the local usage. Compared to a wet FGD system, the construction cost is comparable. The operating cost is estimated to be 60% of the conventional system. The incremental cost of adding NOx control is only a few percent. There is also a mercury capability. There is an organic phase which captures the mercury in an organic complex. The concentration builds up over time. It has been estimated that after about 5 years, the organic portion has to be treated to remove the mercury complex.

Jay Crilley of Novinda reported on mercury removal in dry scrubbers. Novinda was spun off from a joint venture between ADA and CH2MHill. The company was formed in 2009. The process uses amended silicates as a reagent to react with mercury. SO3 interference appears to be negligible in pilot tests. The ash resistivity is improved and there is no carbon contamination of the ash. The active reagent is clay based. The mercury in the gas stream is oxidized and then reacted to form mercury sulfide (HgS). This mineral (cinnabar) is very insoluble and stays on the particles. The reagent must contact the gas in order to react with the mercury. The material does oxidize the mercury. Plant tests indicate over 80% oxidation. The material also improves the ash resistivity so that ESP performance is improved. Three demonstration projects exceeded 95%, 90%, and 94% mercury reduction. For the largest unit of 400 Mw, the reduction was over 94% and the ash met all of the criteria for ash utilization. The mercury concentrations have been consistently below 0.5 lb/trillion BTU. The injection rates are typically half of halogenated activated carbon. Tests have been run on about 20 full scale plants. At one 110 Mw plant using PRB coal with an SDA and an SCR, testing was done on 3 different injection locations. Injection rates are about 3 lb/MMACF (about 100 lb/hr). At half the rate, the collection dropped to 90%. The mercury level in the ash increased from 0.3 ppm to about 1 ppm. In order to achieve 1 lb/trillion, the injection rate of about half the halogenated PAC was demonstrated. This results in a cost that is 30 - 40% lower than PAC injection. The material does not work well on a hot side ESP.

Royce Warnick of Hamon Research Cottrell reported on ESP technology and MACT compliance. The targets for the subcategories on particulate matter (PM) are many and varied and still changing. In the ESP, discharge electrodes put an induced charge on the particles which migrate to the collection electrodes. Internals lifetimes vary depending upon the acidity of the gas, but are generally in the 20 - 40 year range with many units operating for longer periods of time. Concerns include the condition of the internals, gas flow distribution, and impacts from possible additives to the gas stream. The rapping density refers to the square feet of collecting electrode surface per device. Older units have more square feet per rapper. Doubling or tripling the number of rappers can help improve the performance. Current density increases can improve collection efficiency. The smaller the area within an ESP that is discreetly energized by a single power supply, the better the ESP performance. The work gets done in the direction of gas flow. The more discreet departments, the better the performance. There is also an opportunity to better utilize the cross sectional area by dividing the number of discreet sections. High frequency, switched mode power supplies will improve performance. With these supplies, the voltage recovers to peak in less than one full cycle. Units can be revamped and enlarged. Internal space can be converted into more electrode capability. A parallel chamber can be added. The height can also be increased, but there are some limitations on this approach. Optimization of length and height can reduce emissions by 70%. Reliability can be improved by replacing weighted wires with rigid wires, more robust collecting plates, adding T-Rs or SM Power Supplies, micro processor controls, and power monitoring. Flue gas conditioning is still an option. Gas flow distribution improvements can help improve performance. An adjunct fabric filter can also be considered. The order of implementation would be good mechanical condition, increased rappers, increased sectionalization, gas flow corrections, gas conditioning, rebuild expansions, and then add on equipment. Lower gas temperatures for cold side ESPs will help reduce the volume of gas and thus increase the residence time of the gas, helping to improve performance. Kevin Moss of Tri-Mer reported on ultra temp filters and ultra cat catalysts. Ultra temp uses a ceramic filter that can operate up to 1650 F. The system operates in a similar manner to a reverse jet bag house. The capital cost as a particulate filter will be higher than a bag house. A sorbent can be added to remove SO_2 and HCl. There is also a mercury option. With a catalyst on the ceramic, dioxins and furans can be collected. Original applications were for military ammunition testing. Glass furnaces can also use the technology. There are now thousands of filters in operation. Filter life ranges from 5 years for pyrolysis and aluminum to 10 years and longer for other applications. Consistently the output has been 0.5 - 1.0 mg/Nm3. After about 2300 cleaning cycles, the pressure drop increases by 3/4 inch and it will be time to clean out the filter. The advantage of having a filter is that less sorbent is required to achieve the same level of removal. By including SCR catalyst on the filter, NOx reductions can be achieved. Since there is very little penetration of the ceramic filter by the ash, the imbedded catalyst on the inside of the catalyst is protected. Because this filter can be used at higher temperatures, the filter can be placed in the gas stream at higher temperatures and remove particles before the economizer or air heater to help those heat exchangers stay clean. In this application, the catalyst is less sensitive to oxidizing SO_2 to SO_3. Modular shipping and installation helps to reduce construction costs.

VII. Sorbents and MACT Compliance Possibilities - Panel

Melissa Sewell of Lhoist reported on calcium dry sorbent injection for acid gas control. The main message is that hydrate can be a solution for SO_2 and HCl removal. Calcium based by products can also have beneficial uses. The need to reduce SO_3 (for PM2.5 and PAC issues), renewed the interest in using dry calcium based sorbents for boilers. Industrial Boiler MACT has now requirements for HCl control. The flue gas properties determine the optimal effectiveness of dry sorbents. Either selective capture or multi emission capture can be designed with different injection points. HCl removal improves with lower temperatures. Boiler injection benefits SO_2 capture. Hydrating the lime with attention to the surface area and pore volume improves the reactivity of the material. Mixing issues, residence time, and injection points are all important factors in overall performance. With the reduction of SO_3, less PAC needs to be used to capture mercury. Leaching from calcium based ash is an order of magnitude lower.

Rich Miller of ADA reported on providing systems to meet the myriad of rules. As such they are a sorbent user. The goal is to develop low capital cost solutions to go from the coal inputs to the back end treatment. Coal additives may help with mercury or NOx control. Flue gas conditioning can help the performance of particulate capture systems. Dry sorbents for SO_2, SO_3, and HCl can reduce those emissions. Powdered activated carbon (PAC) is typically used for mercury reduction. CFD modeling for optimized gas distribution is very important to good performance. ADA is also working on CO_2 capture with dry sorbents. They are currently at the 1 Mw size testing.

Robert Huston of ADA Carbon Solutions reported on activated carbon advancements for mercury control. In the last decade, the standard PAC that was used for water treatment was found to capture mercury from flue gas. Adding halogens like bromine were known to enhance the capture properties. More recently, optimization of the properties of the activated carbon for gas treatment (including SO3 tolerance). Activated carbon is stable at relatively high temperatures. It is the ability to capture the mercury in the vapor phase that is important. Compatibility with dry sorbent injection will be a requirement going forward. The 3 key steps are mercury oxidation, contact with the media, and capture and retention of the mercury. The PAC technology is the only one that does all three. Other technologies can do one or two and might be used in conjunction with one another.

Carl Laird from Carmeuse Lime and Stone provides calcium based products for various industrial processes. While limestone has been primarily used for wet FGD systems and CFBs, the MACT rules for chlorides have increased interest in lime based products. Hydrated lime does well for SO2 and chlorides, but can impact the ESP. Testing is going to be required in any case.

Travis Vaughn of NatronX Technologies used to be part of FMC. NatronX is a new joint venture company that provides trona and sodium bicarbonate for DSI applications. Two of the partners have mining resources for these materials. Testing is needed to determine which material will work best for any given application. The advantage for DSI is usually the low capital cost (perhaps 1/10th of a wet scrubber). The technology has been tested since the 80s.

Yougen Kong of Solvay Chemicals reported on dry injection with trona or sodium bicarbonate. The chloride levels for solid fuels are likely to be 0.022 lb/MMBTU and an order of magnitude lower for gas and liquid fuels. Waste to energy plants in Europe have been capturing HCcl and SO2 down to levels of 5 mg/Nm3 using sodium bicarbonate. Waste residues are expensive to dispose of in Europe. The plant switched to sodium bicarbonate from lime about 8 years ago in order to reduce the amount of solid waste. The additives are shipped in powder form. The bulk density is about 50 lb/ft3 for trona to 60 lb/ft3 for bicarbonate. These materials calcine at temperatures higher than 275F, forming a high porosity substance. The dry injection system typically involves a silo with air pickup and a fan with duct work to the injection point. The goal is to distribute the solids so that they are well mixed with the gas. The temperature should be kept below 275 F prior to injection to avoid premature calcination.

Bob asked the panel for the 3 most important issues for selecting one of these technologies in order to preserve the coal option for the industrial sector. Understanding what will be done with the ash, handling the material (particularly the soluble salts), and evaluating the whole process are the 3 top candidates. Relative to the order of absorption, SO3, HCl, and then SO2 provides the order of the gas reactivity. Moisture helps the absorption. Moisture is not needed for HCl, but may be necessary for high SO2 capture. Testing will always be required and a budget to test is a necessity. The overall picture is required to address all of the issues in the plant.

VIII. HCL - Bob Davis, Airgas

Bob pointed out that monitoring for HCl is a somewhat different problem from NOx.. The current method is being reviewed and uses an isokinetic sampling method. HCl needs some moisture for stability while NOx is dry. Sampling lines are Teflon rather than steel. A new method 18 is being prepared. Calibration gases are more of a problem and need to be stabilized.

IX. Boiler MACT Requirements for Area and Major Sources - Christi Wilson, Trinity Consultants

There are (or will be) a re-proposed requirements for both Area and Major Sources. The rules were issued in March, 2011. A revision was issued in December, 2011. However, there was a stay of the rule (which was subsequently vacated by the Court) along with some re-proposals. At this point in time, the compliance date is March, 2014. A "final" rule was expected this summer, but it looks like the rule will not come out until after the election. EPA has issues "No Action Assurance" letters that have been extended to December, 2012. A major source is one that has the potential to emit 10 ton/yr of any one HAP or 25 ton/yr total HAP. EPA created more subcategories in the re-proposed rules. They also allowed total selective metals (TSM) emissions limits for metallic air toxics. The biggest change was to go to a work practice standard for dioxins and furans. The compliance dates for new units are 60 days after the rule goes final or the start up date. For existing units, the compliance date is 3 years from the finalization of the rule. At this time, the compliance date is officially March, 2014. Thus, a year and a quarter has gone by without having a real final rule in place. It is "hoped" that the final version to be issued later this year will also change the compliance date. Work practice standards have been proposed for start up, shut down, and malfunction. There are monitoring provisions and record keeping requirements that must be addressed. A notice of intent to test is due 60 days prior to the test. A test report is due 60 days after the test. The Area Source rule is still in place. A new subcategory for seasonal units was created. The tune up compliance date was extended to March, 2013. Tune ups are required every 5 years for new and existing units. There were some revisions to the mercury and CO limits for coal fired units. The rules apply at all times, but work practice standards can be followed for start up and shut down. In addition to the MACT rules, there are Non Hazardous Secondary Materials (NHSM) that have been used as fuels. This issue determines which rule applies to a given unit. Traditional fuels are fuels that are defined in the rule as being produced and used as a fuel in a traditional manner (ie coal, oil, gas, wood, etc.). Materials that have been discarded are considered to be a waste. If the waste material is non hazardous, the unit is a waste incinerator and the CISWI rules apply. If the waste material is a hazardous waste, the unit is a hazardous waste incinerator and different rules apply. If the material is a Municipal Solid Waste, the MSW rules apply. Considerations include how many pollutants are regulated, which particular pollutants are regulated, which standards are more favorable, all of the implications, use of alternative fuels, and NSPS modifications. The compliance dates are different for CISWI units and could be as much as 5 years from the issuance of a State Implementation Plan (SIP), or possibly 2017 -8. A compliance strategy needs to be developed. Major or Area Source designation needs to be decided. Fuel selection and flexibility needs to be considered, as well as energy and electricity requirements. Training and involving senior management is critical. External resources need to be identified early. Nearly everyone needs help on this. The time line for compliance will be critical, but we don't know what it is. This puts more emphasis on developing the discrete steps that need to be taken. Compliance testing is a major effort and needs to be planned and budgeted with flexibility. Data management will be intensive and ongoing with monitoring, record keeping, and reporting. A plan will be needed to handle all of this data so that reporting and record keeping requirements are not compromised (the source of most fines). For those that plan to switch to gas, consideration needs to be given to what happens if everyone else has the same strategy. Gas supply is a serious consideration. Planning, authorizing, engineering, designing, permitting, fabricating, delivering, installing, and commissioning all take time. There is also competition for gas from utilities, diesel engines, and chemicals. The EPA has just proposed a wide sweeping suite of new air quality regulations targeting all sectors of the natural gas industry from drilling the wells to delivery to the customer. The oil and gas industry will report their first round of GHG emissions data to EPA in September 2012. This will likely result in additional regulations. Shale gas states are struggling with air permitting of upstream natural gas operations and associated emission sources. Thus, supply and price are still an issue for natural gas.

X. Compliance Audits - Lauren Laabs, Mostardi Platt

Besides the rules that are about to be issued, there are a host of rules that are already in existence that plants are supposed to be in compliance with. The reason for doing an audit is to find problems yourself before the authorities (EPA, OSHA, State, etc.) find these problems and start the fines. In addition, a baseline can be established and systems can be tested. Subsequently, any deficiencies can be fixed. Before doing something new, compliance with existing permits must be certified. Regulations include federal, state, and local regulations. There are also industry standards as well as corporate policies and procedures. For an independent audit, history should not be the focus of the audit. The audit scope should be clear. Things outside the audit scope or the auditor's capability should be avoided. Advice should not be part of the audit report. Opinion should be avoided. Audits can be focused or comprehensive. Large plants can be plant wide or subsystem focused. Audits can be based on exceptions only or with documented successes. Audit programs can be internal, third party, or a hybrid. A decision has to be made on "privileged" communications. The first thing to do is to fix the problems. Share the successes. Root causes should be identified. A plan should be created to assure that the problems that have been found will not occur again. Title V permits often have special conditions. These are federally enforceable and must show compliance. CEMS and DAS are very common areas for problems. These systems are often made to serve more than one purpose. The production people want to control their process and make product at the lowest cost. The regulatory people want to make sure that the plant is in compliance. Even things such as having the right units can be a problem. Record keeping is another area for common problems. A Title V report may have the information that is needed for NSPS, but the format is different. Separate reports are required. Training and training programs are often required in many areas. Un-permitted Activities and Sources are another area for problems. Tuning events can be a problem as emissions often spike during these activities. This could cause problems depending upon how the permits are written. Management systems need to recognize that this whole activity is a continuous process, of which the audit is just a piece. There is corrective action, planning, and implementation as part of the process.

XI. CEMs, COMs, and QA Planning - Steve Schmitt, Air Quality Services

COM systems are for opacity. CEM systems are for continuous emissions compliance.

CPM system are for parameter monitoring (pressure drop, pH, O2, etc.). The monitoring plan is a major component that is required by the rules such as MACT or NSPS. These rules usually require compliance demonstration initially by stack testing and then ongoing by continuous monitoring systems. Continuous means just that – 24/7, all the time, never ending. These systems all involve planning, evaluation, initial documentation, capital expenditures, day to day documentation, on-going labor costs, and lead time. Day to day activities need to be considered as part of the plan. A calibration check may or may not cause a problem. If the instrument fails a calibration check, that may have an implication as to whether or not the unit is really in compliance. Data recorded during out-of-control periods should not be used. Other data should be used to infer compliance during the check/repair period. Oxygen and Particulate Matter CEMs are going to be required for the MACT rules. Leak detection systems for fabric filters are now being required. Additional monitoring requirements may include operating hours (for limited use or seasonal boilers), parameters in additional to emissions, and activities. Record keeping and reporting requirements need to be addressed. The monitoring plan itself must be made available to EPA if requested. The plan needs to include all equipment (with serial numbers), specifications, calibrations, O&M procedures, QA procedures, probe locations, record keeping procedures, reporting procedures, and performance evaluations. Whatever is in the plan must be done. Therefore, don't add tasks that can't be done. All of these things take time. It is important not to wait until the last minute to start the process. Other potential uses for the data should be considered.

XII. CEMs Technology - Panel

Ken Greaves of Cemtek Instruments reported on dilution and full extractive systems. One of the first decisions that has to be made has to be the type of sampling system that is required for the type of gas analyses that will be needed. The system needs to be compatible with the boiler system in question. Fully extractive systems take a sample and dry the gas. The dilution systems take the sample and add a gas to dilute the sample so that the moisture can be retained. There are also hot-wet systems, in situ systems, and ex situ systems (measurement made near the sample location). The sample is usually transported from the sample location to a remote location for analysis. For compounds to be measured, low concentrations may preclude the dilution system. Mass emissions require a flow measurement. Flow measurement is done on a wet basis and dilution is done on a wet basis so the two are compatible. The dilution system is low maintenance and generally more reliable for solid fuel fired units. Fully extractive has more equipment and, as such, more maintenance but can handle lower concentration levels. These systems are used on gas fired units, especially when low concentrations are encountered (ie 1 - 5 ppm). There are a number of measurement devices that can be used with such a system. Heated probes and heated lines are usually maintained. Moisture content needs to be determined, especially for flow measurements. Moisture analyzers have been developed in the past 5 years that are making this measurement more reliable and routine. There are more pumps and equipment in the full extractive systems. In the dilution extraction system, the sample gas is diluted with clean, dried, instrument air. This system minimizes the maintenance level that is required. The sample line cost is reduced, but must be freeze protected. The system is relatively simple to operate. The gas does not have to be conditioned. The probe is likely to be heated. Out of stack probes are now being favored for dilution systems. In this system, a nozzle is added to the side of the stack in order to divert some flue gas towards the sampling system. The probe for the analyzers is outside of the stack for ease of maintenance and access. The system is a little more complicated, but with improved access, the maintenance is greatly reduced. The probe also lasts longer. Stack flow monitoring gas now be done with ultrasonic monitors. Pitot tube systems can be used with differential pressure measurements. Probe location (s) are important for getting a good average gas flow. Once the measurement is made, the data has to be put into a form that is acceptable to the authorities. There are a number of different authorities that have differing requirements including EPA, trading markets, and regional entities.

Jeremy Whorton of Thermo Fisher Scientific reported on sampling fundamentals and mercury monitoring. A lot of the instruments that are measuring ambient air are used with dilution systems. Modern analyzers are essentially computers with particular sensor systems. Each gas has some unique characteristics that can be measured. For SO2, ultraviolet fluorescence is used to detect the fluorescence that is caused by shining a black light on the sample. NOx is done by chemiluminescence. NOx is chemically oxidized by ozone which causes the material to emit light. The light can be measured directly. Non Dispersive Infra Red detection is used for CO and CO2. Infrared light is passed through a sample and the gases absorb and re-emit the light. For mercury, light at the right wavelength is shown on the sample. The mercury absorbs and re-emits the light which can be measured at the right wavelength. There is a “gold trap” system which absorbs mercury onto gold. This concentrates the mercury. The mercury can be released and measured in a more concentrated form. A similar system uses charcoal as the mercury trap. For CO monitors, about 1ppm at the monitor is required. If the sample is diluted (say 100:1), the diluted sample may be too low in concentration to make a measurement. For mercury monitoring, an example was shown for a CFB units. A dilution extraction system was used. A NIST traceable calibration gas is not currently available. The probes are silica coated stainless steel. An inertial system is used to separate particles from the gas. This takes out the unburned carbon which would absorb the mercury at the measurement instrument. Once the sample is cleaned of particulates, the sample can be exposed to light, which causes the mercury to emit a characteristic frequency of light which can be measured. Mercury was measured at a 500 Mw utility unit at 15 - 35 micrograms/m3. The CFB unit that was measured was operating at 0.2 micrograms/m3. RATA results were at 0.6 - 1.6 microgram/m3 for validating the instrument. In Brazil, there are monitoring stations in the Amazon jungle. Due to the time it takes to get to the jungle, it would be desirable to know what might be wrong with an instrument. Every instrument has a number of measurements inside the instrument about the health of the monitor. This data can be transmitted to a central point to provide information so that replacement parts can be sent to the jungle along with the instrument technician for immediate repair.

Brian Conway of Sick Maihak reported on acid gas monitoring. The Sick mercury monitor uses a heated quartz cell that converts all mercury into elemental mercury. An electromagnet is used to provide a very specific peak on the absorption spectrum (Zeeman Effect). This system tends to eliminate interferences. NDIR is used for HCl, ammonia, SO2, and other gases. A tunable diode laser can be used for HCl. FTIR has been the standard method for HCl, but now EPA is allowing other methods. Particulate monitors are now being installed. In one utility case, the data was very noisy. The ESP rapper system was part of the problem. Once the ESP rapper system was corrected, the noise was greatly reduced, as were the emissions and the power requirements for the ESP. At a wood fired installation, the particulate monitor indicated problems with the ESP. The SCR catalyst was being blinded by excess particulate emissions. The ESP was corrected as a result of the data from the monitor and the ESP performance improved. With the improved ESP performance, the catalyst blinding problem was greatly reduced. For chemical recovery units, the UV spectrophotometer with differential optical absorption spectroscopy (DOAS), the total reduced sulfur compounds can be measured directly. This is done by measuring several of the different sulfur compounds and summing them up. Sick has developed a self alignment device to keep the probe properly aligned. They are also using an ultrasonic probe for flow measurement.

XIII. Boiler Tune- Ups - Norb Wright, Consultant

Tune ups are required for many different units under the various MACT rules. Area sources will require boiler tune ups on a regular basis. The tune up is required to report at a single point at full load. The requirements include burner maintenance, adjustments, and repairs. The unit should adjust the air flow to minimize CO emissions consistent with manufacturer's recommendations. The EPA has developed a tune up guide. The guide was developed under the auspices of DOE. The guide was, of necessity, general in nature and focused on natural gas. The theoretical section discussed losses, but did not include the moisture loss. For the most part, when tuning the boiler, the losses are not really analyzed other than for excess air. Casing losses, radiation, etc. are not generally part of the control system. The practical section was directed towards a jack shaft control system for a natural gas fired boiler. There is an economic analysis section. However, since the tune is mandated, this section is not really necessary. A written work scope should be prepared. Select the tuner carefully. Document the process thoroughly.

XIV. Energy Assessments - Fred Fendt, Dow

Dow is one of the largest industrial energy users in the world and uses nearly 900,000 bbl/day of oil for both energy and products. At Dow there are two kinds of assessments. There is a technical energy assessment and a "lean" assessment. In the lead assessment, the entire process from purchasing to product is looked at on an overview basis. The technical assessment focuses on the production/consumption part of the plant. This is a deep drill process using equipment manuals, flow diagrams, heat & mass balances, models, operating instructions, etc. The purpose is to understand the process technology to determine if potential exists. A preliminary opportunities list with potential savings and estimated costs is developed. The list is discussed with the plant personnel to determine feasibility. Typically 20 - 50% energy savings can be achieved. The lean assessment is a broad view to identify low or no capital opportunities with immediate impact. Energy Best Practices from other industries are utilized as well. Typically 5 - 25% energy savings can be achieved. Systems are broken down into non-complex, complex, and complex with conversion. The work process starts with someone deciding to do an energy assessment. The first one is always the most difficult. A site contact needs to be identified and assigned to the assessment. There is a kick off meeting, data collection, and then the analysis. Improvement projects are started immediately. Non-complex sites are done in 4.5 days. For a complex site without conversion (no energy generation) is also 4.5 days. For the complex site with conversion the assessment takes about 7.5 days. Since 1990, the energy intensity of the entire, world wide product slate has been reduced by 38%. The avoided fuel cost was over $9 billion. The cumulative fuel savings was 1.7 quadrillion BTU.

XV. Boiler Tune ups & Assessments - Denis Oravec, AAI-JMP

Tune ups and assessments focus on 3 main items – the state of the boiler, the performance relative to requirements, and the basic practices for control and operation of the unit. Significant energy losses associated with boilers fall into two categories – stack losses and radiation/convection losses. Stack losses include dry gas losses, moisture losses, and combustion inefficiency. Once the fuel is fixed, excess air and exit gas temperature are the two main parameters. As excess air is reduced, the overall boiler efficiency is increased up to the point where CO and unburned hydrocarbons start to increase. At some point, the combustion process becomes relatively unstable with respect to combustion efficiency. The tune process includes a physical inspection, an evaluation of boiler operation and conditions, maintenance procedures, control configuration, output characterization, PID tuning, load tests and loop tuning, mixing, and air distribution. During inspection, look for proper location of the transmitters and flue gas analyzers. Check for proper alignment of actuators. Calibration frequency and records, especially for O_2 sensors, are important. Air flow accuracy becomes more important as emissions standards are becoming more stringent. The control strategy for the unit is necessary in order to understand the air trim, fuel/air ratio, air splits, cross limits, and feed forward capability. Actuator characterization, in terms of position vs. flow, is critical to getting tight air flow control relative to fuel flow. Stickiness, hysteresis, non-linearity, etc. in the actuator relative to the actual air flow need to be characterized so that the controller will know the air flow for a given actuator position. It is a good idea to get a report on the conditions found. It might be necessary to get the unit in shape before final tuning occurs. The results of the tune up and recommendations should be in another report. Baselines should be established both before and after the tune up. It is a good idea to do a tune up once a year, regardless of the regulatory requirements.

XVI. Combustion Technologies to Achieve MACT - Edmundo Vasquez, Clyde Bergemann

It is important to tune up the boiler before embarking on any control strategy to limit emissions. By establishing a baseline, the requirements for reductions can be addressed. Clyde Bergemann provides equipment for all 5 of the potential emissions requirements for the Industrial Boiler MACT. There are a number of processes that can be impacted within the furnace. From the initial solid fuel, the particle heats up on entering the furnace and begins the combustion process. Early combustion products include volatile matter, particles, CO_2, CO, and water vapor. The ash particles can reach the wall and potentially stick or deposit on the wall. Alkali metals will vaporize from the fuel particle. As the flue gas cools in the furnace, these alkalis will condense to form very fine particles. As the fuel burns, the bulk of the combustion products include CO_2, N_2, O_2, H_2O, CO, NO, SO_2, and unburned fuel. Of these CO, NO_x, SO_2, and VOCs are considered to be pollutants and are under regulation. CO can be generated during combustion when the air and fuel are insufficiently mixed. NO_x can be formed by either thermal formation, fuel nitrogen, or “prompt” NO from radicals in the early stages of combustion. Sulfur ends up as mostly SO2, with small amounts as SO3 and particulates. Improving combustion and reducing emissions in the furnace requires the proper burner and boiler designs to be operated in a balanced manner. Tuning, low excess air, over fire air (or under grate air), fuel distribution, and controls can be checked in order to optimize operations. Air staging, burner upgrades, SNCR, dry sorbent injection, and smart soot blowers are possible modifications for emissions reductions. A combination of techniques can be utilized to achieve the desired emissions rate. To meet the MACT requirements for CO, the combustion process needs to be optimized with respect to fuel and air. For stokers, the over fire air system will be most effective in improving the combustion process. The interlaced, overfire air system can improve the overall mixing. However, if the interlaced system is used to create two vortices both in the horizontal and vertical plane, the particles can be internally circulated in the gas flow, which gives them more time for combustion and more opportunity for mixing. Engineering tools include cold flow modeling, CFD modeling, and operational data.

XVII. CHP as a Profitable Soultion to MACT - Eric Gottung, Recycled Energy Development

CHP is not a panacea, but under the right conditions can afford a means to help resolve some of the issues associated with MACT. Recycled Energy will build, own, and operate plants that can provide steam and electricity to industrial plants. Recycled Energy has agreed to work together with ERM to develop such plants. Power generation is constrained by the second law of thermodynamics to reject heat when converting heat into work. Some 15 % goes up the stack and 40 - 45% goes to the condenser. The other 5 - 10% is lost in parasitic power within the plant. In combined heat and power, some power is recovered from the steam, but rather than throwing the heat away in a condenser, the steam is used for process applications. In this case, only the stack loss and parasitic losses come into play. Alternatively, a gas turbine can be used to generate power. The exhaust gas can then be used to make steam. The steam can also run a back pressure turbine and then be sent to process use. In this case, more power can be produced. This provides a significant reduction in CO2 on an overall basis. The difficulty is that the plant may not need all of the power that would be produced. In that case, the power has to be sold. Many coal fired plants are planned to be closed. That power will have to be made up. In such cases, the utility may be more accommodating with regard to offering a power purchase agreement for power generated by an industrial plant. The FERC is actively supporting distributed generation. Some states are also promoting CHP. Municipal power companies and electric cooperatives tend to be more interested in purchasing power. A recent example showed that a coal based plant with old boilers could be brought into compliance with the retirement of half the coal fired boilers and a new gas fired boiler, plus controls on the remaining half. Operating cost increases were very modest. Two gas turbine solutions were also evaluated. In one case, modest size and power generation would save money and reduce CO2 emissions. The larger power supply system would definitely require a power purchase agreement, although the cost savings would be larger and the CO2 reductions would be greater. Of course, the capital cost increases in going from the modest solution to the major power generator.

XVIII. Maintaining Fuel Flexibiltiy with Grate Fired Boilers - Bob Morrow, Detroit Stoker

Coal is good. However, it has some constituents that cause emissions issues. Coal is also variable. Fuel analysis shows considerable variability for mercury and chlorine that makes betting on fuel content for these substances to meet compliance. Co-firing is one way to account for some of the variability in coal. Wood chips, pelletized wood, TDF, and some agricultural pellets at the 1 inch size level can be used up to 10% without impacting the boiler significantly. On one grate fired boiler, the co firing of 10% biomass showed slightly lower emissions for the standard compounds, with the mercury considerable lower. However, the coal had significant chloride and the biomass had significant chloride. However, this approach reduced the problem to concentrating on the chloride issue. Lime kiln dust is a waste product from a lime kiln. This material can be used to reduce the variability in sulfur emissions. Landfill gas can also be used as a supplemental fuel. One result was significantly lower CO emissions. There is a multi component catalytic reactor that can assist in CO and NOx reductions. Natural gas can be used as a supplemental fuel. In one stoker plant, the SNCR system caused excessive pluggage with ammonium salts. In this case, with under 10% combustion of natural gas, the SNCR system was eliminated and the unit was able to run without pluggage. Higher levels of natural gas firing can be used up to 30%. It is possible to take the grate out completely and install an upward fired boiler.

XIX. DSI and ACI Demonstration Testing - Ryan Zupon, Sega, Inc.

Sega is an engineering firm. They have done some testing for owners on dry sorbent injection and activated carbon injection. In dry sorbent injection, the additive is injected downstream of the furnace. Air handling is an important consideration in moving the sorbent into the silo and into the duct work. Activated carbon injection systems are similar in nature. The fuel additive is either calcium chloride or other halogen salt that can be sprinkled on the coal belt with the coal to improve the oxidation of the mercury in the furnace. When additives are used, the particulate control system needs to be addressed. The ESP can be upgraded or the plant can convert to a bag house. With the new bag house, a new fan will likely be required, which will likely drive the cost up. In general, it would be desirable to retain the ESP, if possible. ESP modeling will likely be required in order to determine if the PM limit can be met with the required amount of additives. A demonstration test will likely be needed to confirm the performance of the system and to check the balance of plant ability to handle all of the new requirements. It is also a good idea to establish the maximum capability of the technologies deployed. An adequate budget for testing needs to be allocated. The level of testing management also needs to be determined. A baseline test is a good idea, followed by parametric testing. A significant period of operation at the selected conditions is also desirable. There is also a mobilization and a tear down period before and after the test. Low load compliance will likely need to be scheduled in advance. Sampling schedules, stack gas testing, and load conditions all need to be identified. The staffing plan is important. It will be necessary to coordinate the requirements. Interfaces need to be clearly identified. One example was an 80 MW, PRB fired unit to meet the MATS rule. The ESP had been rebuilt. There was a cyclone separator in front of the ID fan. The site was checked prior to set up and a list of equipment that was needed was identified. The silo was set up in the first 2 days. The activated carbon injection unit was able to be set up with a fork lift. The baseline HCl emissions were 0.008

lb/MMBTU. The baseline PM emissions was 0.0004 lb/MMBTU. SO2 reductions were better than 80%. The fuel additive for mercury was very effective. There are a lot of testing reports available. These should be checked to see if something similar has been done for your unit. Mixing is a key factor in sorbent utilization. Take advantage of opportunities to promote mixing. Milling of sorbents also improves utilization. For sorbent injection systems, the major cost is the cost of sorbent over time.

XX. Fundamentals of Working with State Regulators - Patricia Aho, Commissioner, DEP Maine

Pat provided some helpful anecdotes from her experiences during the past few years. The Maine DEP is responsible for safeguard the air, water, and land for the State of Maine. Communicate early and often. Utilize regulators as a resource. Educate the staff about the facility and its operations. Submit complete and thorough applications. Respect the various time frames required. Prepare for meetings in advance. Research the people you will be meeting with. Take the time to research the laws and regulations that might apply to your project. Don’t send sales people to make technical presentations and be mindful of the time. Be familiar with the written materials that you bring to the meeting. Send people that can answer questions. The regulator has the knowledge of the rule and regulations and the regulatory process. Use the regulator as a resource. Don’t be afraid to ask questions. The regulator also knows what has worked successfully in the past. Submittals need to be complete and comprehensive in order fo the process to proceed smoothly. Include time for review, drafting, and comments in your planning. Be clear on scheduling needs. Make sure the information is correct and accurate. With regard to inspections, be available. Follow up on suggestions. Know what is in the license or permit. If there is a non-compliance issue, understand the process and be responsive. Send people with appropriate authority to meetings. The State wants to resolve the situation quickly. Penalties gather daily. Be proactive. Get involved in the process and educate the State about your process. Build a healthy relationship with State regulators.

XXI. What Have I Heard This Week? - Panel

Carl Bozzuto pointed out that a strategy is needed. It is no longer a matter of having a technology or a piece of equipment. There are many ways to approach this problem and many rules and regulations that have to be satisfied. The rules have become political and are no longer health based. From everything to tune ups and audits to equipment selection to fuel choice, a strategy is needed. This year seemed a little more positive than last year. Presuming that the rule comes out with a work practice standard for dioxins and furans and a CO limit that is reasonable, there were several presentations that indicated approaches that could potentially meet the chloride, mercury, and particualte requirements. Even so a strategy is needed. The Eastman presentation dramatically pointed out the need to look at the entire plant in the overall context. We also heard that natural gas was not a “no brainer” decision. There are still issues of future price, future supply, and future regulations on that industry. Reference the permitting stories on gas from the start of this meeting and some of the other CIBO meetings. Thus, while there is still a great deal of uncertainty, there is some hope that some of our solid fuel fired units will survive.

John DeRuyter noted that regulatory uncertainty and moving targets have made it very difficult to chart a path for compliance and the associated investment. There are more rules coming as well as litigation. The Industrial Boiler MACT is at least 10 years in the making and counting. The use of a fuel variability factor is a critical approach that needs more attention from EPA. The chloride variability is one of the key concerns. The viability of coal is under pressure. The coal cost has risen in recent years. Higher quality coal will likely be required to routinely meet limits on all of these compounds. Exports of coal are putting a floor on coal price for export quality coal. Natural gas conversion has to be balanced again long term demand and price. Electric generation is consuming larger quantities of gas. Eventually, LNG exports of gas will start to balance the price. Combined heat and power or self generation brings in issues of back up power and reliability. Modeling requirements for gas permits are as difficult and time consuming as other modeling requirements. Physical limitations at existing plants may not allow for the installation of new equipment. Testing to identify a baseline is a good idea, but funding for such tests is problematical. Capital availability and priorities are serious concerns for most companies. Personnel resources availability can also be a constraint.

John also reported on some information that was given to OMB and EPA under comments to the rule. The data showed essentially no correlation for organic compounds against CO at CO concentrations from 20 - 90 ppm. The variation of moisture and volatile matter was significant. The volatile matter was 38.5% with a variation of 1%. There was no correlation for organics against any of the operating parameters.

Chirsti Wilson of Trinity noted that there are a lot more requirements of permitting activities. The environmental groups are challenging nearly every permit, including natural gas units. These groups are banding together to file extensive comments and objections to projects. Some states are overwhelmed with permit applications.

Cathy Beahm of the State of New Hampshire noted that there was a little more positive energy this year compared to last year about the Boiler MACT rule. There is still an extreme amount of uncertainty as the rule keeps getting delayed. There is an extreme amount of complexity with regard to the level of rules, the interaction of the various rules, and the number of paths to comply with the rules. Tune ups are definitely a valuable tool to improve operations. Tune ups and maintenance should be done before a testing program is established. There is no “silver bullet”. Care also needs to be taken that in solving an air problem, a water problem isn’t created. There is a lot information present within the CIBO community. Guidance documents on things like solid fuel unit tune ups, comparisons of technologies, record keeping, etc. Outreach to those who are not necessarily in the loop.

Norb pointed out that energy options are narrowing. Coal is being squeezed as an industrial fuel. It is being impacted by cost, regulations, and perception. Natural gas is a logical alternative at current prices, current regulations, and current supply. However, there are “rumblings” that natural gas isn’t as clean as it is made out to be. A whole suite of regulations are being proposed for the oil and gas industry. Environmental groups are starting to protest gas permit applications. Biomass has availability issues as well as questions on the “true” carbon neutrality of biomass. “Green” sources are not the panacea. Renewable sources can be utilized, but is not easily expanded to the levels of demand required by industry. Energy efficiency is one of the better ideas of MACT. Tuning should have been done all along. Energy audits will provide some impetus towards conservation, but low gas prices may limit the payback associated such projects. We are in the 12th year of MACT with no definitive end in sight.

XXII. Question Development - Andy Bodnarik and Bob Fraser, facilitators

Andy reviewed the summaries from the owner's forum and the equipment supplier's forum. Evaluating the "big picture" came through in several presentations. The goal of this session is to develop a list of questions that can form the basis for discussion in the next session.

- rapid response for steam demand and compliance implications
- sell flue gas to a third party and have only one set of regulations
- compliance cost needs to be considered in all instances
- PSD issue for CO on gas (7ppm SIL).
- mineral analysis of solid fuels and implications for long term operations
- will nuclear play a greater role
- high O2 will reduce CO, but increase NOx
- how to avoid stranded capital
- how to provide incentives for CHP
- how will compliance tests be done when dates are tight
- how will states be able to handle all of the requests
- how many alternate gases are out there (type and quantity)
- where will we get the technical people to install, test, operate, and maintain the equipment
- how can CIBO get more accurate information out to the public
- larger alliances that can help change perceptions of business and industry
- do equipment suppliers see China as a source of equipment and implications for quality
- why do you need steam
- waste definition will make it more difficult to use opportunity fuels
- are plants ready to handle the level of data generated and potentially needed for compliance
- can we optimize the permitting process
- how does a university cope with no rule and a need to sell bonds for equipment
- how do we stop the rush to gas so that we don't shoot ourselves in the foot
- expedite plans and approvals from states that are inundated
- are we pushing the control systems such that "manual control" is no longer possible
- good data is needed in order to design good equipment
- what is collective power and influence of CIBO and how to apply
- what should we do with the time until the rule is out
- what are the next round of limits
- how can we work with EPA to get clarity on what's a fuel or what's a waste
- how will new rules impact employment
- what is the "end game"
- what are the signs that would indicate that this is the rule that will stick
- how can we use QF status to use alternate fuels

- can we benchmark with others on energy assessments
- are we providing enough training to existing employees
- how can industrials have a stronger voice in articulating the benefits of CHP
- how come natural gas doesn't emit HAPs

XXIII. General Discussion - All

Bob Bessette noted that the budgets that are available to some of the eNGOs are in the 10s of millions of dollars. The cost of doing a small piece is several hundred thousand dollars before getting it to a news outlet. At this point in time, we do not have that kind of budget. Our most effective work has been the work that we did relating job losses and the MACT standards. We try to take the high road rather than trade barbs with the environmentalists. We do better with "one on one" activities. Andy pointed out that in his early days he worked on a wood fired power plant. Before they put a shovel in the ground, they went out and talked to the people in the area where the plant would be built.

With regard to rapid response to load changes, the question becomes what constitutes an emergency. Hospitals clearly have requirements. There are also safety issues. Regulators need to address this issue and allow some of this activity to be accounted for as part of SSM. With regard to using a 3rd party for emissions control, the point was that there were too many sets of rules for differing entities. This issue needs to be addressed. Another comment was that zero emissions is not achievable. Yet we keep ratcheting down the limits. It was noted that it used to be that the limit was not set below that which was detectable. On the CO issue, the concern is the inverse relationship with NOx. Typical controls for CO tend to reduce efficiency (high excess air, catalyst). Reduced efficiency tends to increase the emissions of all the other compounds. CO emissions from stacks rarely impact ground level concentrations. CO is converted to CO2. The NOx requirement should take precedence. Chemical properties of ash will become more important for ash disposal reasons.

The nuclear question is still up in the air. There will likely be more nuclear plants, but in the US, the likelihood of nuclear substantially increasing its market share is relatively low, just due to the length of time it takes to build a nuclear plants. Avoiding stranded capital cost is often difficult. With all of the uncertainty, it is difficult to make investment decisions. In a similar vein, promoting CHP is another investment issue. Industrial cogeneration is disadvantaged in that the system is usually smaller (negative economies of scale), the cost of money is higher (shorter time horizon, higher rate of return, balance sheet financing), and the electricity is not the primary product (management attention, product marketing, etc.). There have been proposals before. The simplest approach is a production credit. After that everything else gets complicated. Flexibility in meeting the testing and reporting deadlines can become an issue. We don't know if EPA can or will be flexible. However, it would be a good idea to plan ahead. Filing early is one method to get in line. The filing has to be complete and comprehensive. The potential for PSD permit requirements has pushed owners to try to avoid PSD. The treatment across states has been variable. A stack test may have an accuracy of 30%. Putting in a PAC system for mercury control can trigger a PSD issue for particulates if, on the day of the test, the error is on the high side and triggers the 10 ton/yr increment limit. The low number of people with experience with PSD permitting will be a limiting factor. Getting trained people for industry is a problem. Chinese production is not necessarily an answer as China is busy building its own plants right now. Perhaps sometime into the future, China will put together the kind of support teams that will be needed to be successful commercially.

The requirement for continuous monitoring will lead to tremendous data generation. While some of this data might be useful, the sheer amount of data will drive people to put the data in the drawer. Organizing, analyzing, clarifying, and retrieving data is another area that will need more attention. Optimizing the permit process to meet deadlines may require adding time to the schedule in order to meet the appropriate time frames. In regard to how far to proceed without knowing the actual rule, scenario planning can help. A best case, base case, worst case scenario can be prepared with a rough capital spend schedule for each so that senior management is not surprised when the rule is finalized. With regard to lessons from history, the real point was to leave some options open. Instead of killing coal, we should be preserving our options, if only for national security reasons.

Carl Bozzuto

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