Environmental, Energy & Technical Committee Meetings

September 14-15, 2010
Radisson Hotel, Reagan National Airport
Arlington, VA
(703) 920-8600

M I N U T E S

TUES-WED SEPTEMBER 14-15 2010

FOCUS GROUP SESSION

Focus Group Moderator – **Bob Corbin**, CIBO

Bob Corbin introduced the Focus Group topic of Boiler Tune-Ups and Optimization. There will be 4 presentations for this topic.

Energy Efficiency/Performance and Boiler MACT Tune-ups for Small Boilers - **Paul Welch Coggins**, Cleaver Brooks, Inc.

Many owners of small boilers are often faced with the choice of retrofitting or replacing smaller boilers (under 100 MMBTU/hr). Practical solutions have to consider boiler and burner efficiency as well as environmental considerations. Financial metrics help to resolve some of the issues. This approach aids in the development of a plan forward. Boiler and burner efficiency are broken down into 4 categories: base boiler, burner technology, controls, and heat recovery.

The base boiler efficiency (energy recovered as steam divided by energy input) for gas fired boilers is in the range of 80 - 84% as designed. This range should not change over the life of the boiler. The tune-up attempts to assure that the boiler is returned to its design efficiency (as opposed to improving the design efficiency). The burners tend to be very efficient (99% +) at the design level (fuel burned divided by fuel input). Turndown is a consideration for burners. Good turndown for natural gas is in the range of 10 to 1. For light oil, the range is 8 to 1. The boiler should still maintain its efficiency provided that the excess air is not increasing greatly. This means that the burner needs to operate over the load range with the same levels of excess air. In doing so, the NOx levels can be maintained at 9 ppm or less. Older boilers that are more sensitive to turn down, or lack the controls capability to do so, may need to look at a small boiler alternative for low demand periods. The CO level is 25 ppm. For light oil, the NOx level is less than 80 ppm with the CO level less than 50 ppm.

The next consideration is controls. Advanced controls can provide as much as a 5 - 7% system efficiency gain on an annual basis. Control packages should consider oxygen trimming, parallel positioning, variable speed drives, and lead/lag control for multi boiler installations. Oxygen trim keeps the excess air at optimum levels at all times. Parallel positioning minimizes the manual linkage controls for fuel and air. Variable speed drives for motors reduces the overall electrical loads. Lead/lag controls match boiler load requirements with turndown demands. The integrated control system provides for single source responsibility in the control room and requires only a single data link for monitoring and reporting. Heat recovery is the final consideration for efficiency. This depends upon the installation.

A stack economizer can be added to recover energy that would have been sent up the stack. A condensing economizer can be combined with a stack economizer and be deployed to recover some of the moisture loss in the stack. This heat exchanger is designed to operate at flue gas temperatures below 135 F. At these temperatures, water in the flue gas condenses and gives up its latent heat of vaporization which can then be recovered. Heat recovery can also be considered for the boiler water blow down. This serves to prove some feed water preheating. The heat transfer to the tubing can be impacted. Turbulators have been considered, but performance enhancement has not been consistent. Advanced heat transfer tubes have been developed to attempt this heat transfer improvement.

The decisions to be made (such as adding heat transfer equipment or modifying the boiler) require an investment that needs to be recovered through fuel or operating savings. The three most important metrics are net present value, internal rate of return, and payback. These should always be evaluated in after tax dollars. The net present value is the sum of the present value of all future cash flows minus the initial cash investment. The future cash flows are discounted by the discount rate or cost of capital of the investing entity. The internal rate of return is that discount rate which makes the net present value come out to zero. If the internal rate of return is greater than the entity discount rate, the project represents a good investment. Simple payback merely divides the investment by the annual savings to give the number of years it takes to recover the investment.

Cleaver Brooks has developed a financial analysis software tool that evaluates boiler, burner, controls, and heat recovery options. In the example shown, the planned investment aimed to provide an overall reduction of 16.7% in energy expense. The annual savings were estimated to be $88,447/yr. Greenhouse gases were to be reduced by 750 metric tons/yr. There was also a 17% reduction in NOx emissions. The implementation cost was $143,780. The simple payback was 28 months. The IRR was 40.7%. The net present value was $216,838. The discount rate was 10% and the tax rate was 40%. The 10 year cost of doing nothing was $884,471. Sensitivity analysis can be done for various assumptions. The individual changes can also be evaluated (i.e. burners only, heat recovery only, etc.). This provides an opportunity to consider what should be done first.

Thus, the tune up can bring the boiler back to its design condition. Advanced controls can assure that this condition is maintained 24/7 over the entire operation. Replacement burners can improve turndown performance as well as environmental performance. Secondary heat recovery can be retrofitted to improve performance. Finally, if the boiler no longer meets the load requirements, a boiler replacement can be considered.

Comprehensive Boiler Tune-ups for Variable and Full Load Operation - **Clark Conley** and **Roger Leimbach**, Metso Power and Automation

Clark Conley started with the mechanical considerations for boiler optimization. This is the process of matching boiler output with plant objectives. These include environmental constraints, energy requirements, costs, and operator involvement. The plant must evaluate and establish objectives before embarking on an optimization program. The tools include tuning and system design evaluation.

Tuning provides for the plant to optimize performance of existing equipment based on the plant objectives. Boundaries have to be established for the equipment to be optimized. A site visit to establish a base line is needed and a written plan should be prepared. This plan should be as specific and detailed as possible so that the appropriate mechanical, instrumentation, and controls personnel are present at the time of the tune up. Documentation of the results is the final critical step. Documentation provides the key information as to what was done and what was the result.

On the mechanical side, the primary air system should be inspected and repaired to assure that it is working as intended. This includes air ports, grate openings, fluidizing nozzles, piping, duct work, dampers, drives, and expansion joints. The fuel system should also be inspected and repaired to assure proper sizing and flow rates. Furnace oxygen and CO measurement profiles should be developed. Instrumentation needs to be inspected, calibrated, and repaired to assure that the measurements are accurate. As the boiler is operated, the results from the measurements are taken, analyzed, and compared to expected performance. Computational Fluid Dynamics (CFD) can be used as a guide to flow problem corrections. Controls tuning sets the proper control logic and operating parameters to maintain optimum operation. Documentation of all findings and tests is critical. A tuning report should provide a complete story of the effort including objectives, data, settings, and recommendation for enhancement. Concurrent with the tuning study, an evaluation of the system for best practices can also be undertaken. This can provide synergies with the boiler tune up to provide opportunities for overall system optimization.

Roger Leimbach pointed out that when the boiler was built, there was a certain performance that was contemplated in the design. Over time, the performance often deteriorates as certain parts of the unit degrade. In addition, new environmental regulations often require performance that was not anticipated in the design. The challenge of change is to recognize deteriorating performance quickly and to act appropriately. Experts should be brought in, if necessary. Considerations include combustion optimization, fuel BTU compensation, steam header optimization, steam temperature optimization, rate of change optimization, coordinated boiler/turbine control, and network enabled remote collaboration.

Objectives are typically to maintain boiler output to match demand requirements, maintain boiler/turbine or boiler/pressure balance, optimize efficiency and emissions, and protect the boiler from unsafe fuel/air ratios. Before optimization, a testing and performance study is required. Every plant is unique and may require a different optimization approach. The study is usually done in two phases: an on site audit phase and a data analysis phase. A detailed report should be prepared that highlights the process improvement potential, including commercial justification based on criteria established by the plant owner. The study should benchmark current performance, evaluate known issues, analyze upset conditions, and evaluate potential benefits of controls optimization.

The testing should include excess air, boiler leakage, emissions, air splits, bed inventory, bed temperature, fuel feed, limestone feed, and load change conditions. The results from these tests are used in a modeling and simulation program. This simulation can lead to requirements for the control system. The energy demand must be a function of the energy requirement of the steam host in real time. This must account for precise over or under firing and must not be affected by changes in fuel quality or disturbances in the boiler. This balance is not directly calculated from steam flow. The true energy input can be calculated from the heat release. A heat balance calculation can be done, but is slow for real time calculation. However, oxygen consumption is rapid, but not always as accurate. By combining the two, an accurate estimate of the actual heat release can be obtained in real time.

An example was shown for a 240 Mw(e) unit that was using coal and biomass of various types. The test was to increase the coal flow in 15% steps and reducing the biomass flow while maintaining steam flow. By using the calculated heat release, the steam flow was maintained while the unit switched from mostly biomass to 100% coal. Optimization is a trade off between emissions and efficiency. This process is not easy to model and must include operating experience. The system must be easy to upgrade and maintain. A combustion optimizer is an advanced supervisory application for optimized combustion. The backbone of these systems is a set of multivariable fuzzy controllers to regulate several of the combustion variables, including bed level inventory, furnace temperatures, cyclone inlet temperatures, air splits, fuel feed, limestone feed, ammonia feed, flue gas oxygen, and emissions data. The fuzzy logic system is not a "self learning" system. In the real world, most of the processes are non-linear. This makes for a difficult computational problem.

The fuzzy logic looks at all of the performance data that is available, including operator knowledge. Each controller looks at multiple process measurements. Calculated variables are input together with process measurements to provide control, compensation, filtering, and "recipe" outputs that are compared to required set points. Plant optimization goes beyond the boiler. The operators need help. They need a team of experts to provide them with timely information that is needed to optimize operations. The control system has changed. The plant functions are integrated. The new control room is a center for exchange of ideas and solutions. Network enabled cooperative groups can be one approach to resolving this problem. A virtual network of remotely located experts can be supported by future automation systems. Experts can include 3rd party consultants. Automation platforms need to be open for all to use, improve, and integrate.

Solar Solutions to Preheat Boiler Feedwater and Automation - **Carlo LaPorta**, Capital Sun Group

Solar thermal systems can convert more sunlight into useful energy than photovoltaic systems. Low temperature applications can be more efficient and less expensive and will be undertaken first. Solar thermal applications can include air heating, process water heating, steam production, space heating, feed water heating, and drying. Solar collectors can be flat plate or concentrating collectors (parabolic troughs). Solar systems can be effective in offsetting 30 - 60% of the load. There are two approaches: make the boiler itself more efficient (ie use less fuel) or reduce the load demand on the boiler. Natural (or passive) solar heating can be used to recover energy. The wall of a building can be used as a transpiration air heater. A thin metal facing with black paint absorbs the solar energy. Air is forced through the space and is heated. The heated air can be ducted directly into the HVAC system. The roof can be covered with a similar system. This system is a little more efficient since the roof is exposed to the sun continuously. These systems can pay back in 2 - 3 years.

Drying is another function that can be supplemented by solar heat. One example is drying the corn based biomass that goes into ethanol production. These plants also use a lot of 180 F water. The glazed flat plate system is the work horse system for producing hot water in the range of 140 - 190 F. A two tank storage system provides for relatively high efficiency and flexible operation. Evacuated tubes can be used to generate higher temperatures. Concentrator technologies typically use a parabolic trough to concentrate the solar power onto a tube to generate steam. Usually a 40 to one concentration is deployed. Typical systems generate 400 F steam. Some larger systems can go as high as 700 F.

Tax incentives can be very important in the economics of these systems. Accelerated depreciation (5 years) as well as investment tax credits can significantly reduce the capital outlay for a plant. Several questions concerning the potential application of solar thermal to compliance options on MACT arise. These include emissions averaging, efficiency calculations, categories, and emissions rates. The problem for MACT is that the emissions rates apply to the entire load range of the boiler so that reduced loads do not help meet the MACT standards.

ENERGY COMMITTEE SESSION

Frederick P. Fendt, The Dow Chemical Company, *Energy Committee Chairman*
Robin Mills Ridgway, Purdue University, *Energy Committee Vice-Chairman*

Introductions -
Energy Session Introductions - **Robin Ridgway**, Purdue University and **Bob Corbin**, CIBO

Bob Corbin announced that CIBO has picked up 7 new member companies since the June meeting. Bob introduced several of the new member representatives. Bob initiated the usual "round the table" introductions. Lisa Jaeger gave the anti trust admonition. Robin Ridgway noted that Fred Fendt (Chair) was unable to attend due to a death in the family. As he was going to do one of the two topics, we are down to one topic, namely the fuel specification discussion. The Industrial Boiler MACT applies to fuels. The definition of solid waste will impact whether a material will be classified as a fuel or a solid waste. There is a proposed definition of solid waste that is now out for comment. Basically, the EPA Office of Solid Waste has clung to the concept of a solid waste as a material that has been "discarded". A material that is discarded would be considered a solid waste. This would mean that a tire that is discarded to a pile is a solid waste. However, a tire that is kept on site (i.e. not discarded) or that is "processed" (whatever that means), could then be considered a fuel. CIBO has already sent comments to EPA on the definition of solid waste. Further comments or information might be received through the internal EPA review process. This might be done through the Small Business Administration or, ultimately, the OMB review process. It was also noted that EPA is examining the "environmental justice" aspects of hazardous waste. This is another regulatory track that we need to follow. Some groups are attempting to grade or classify materials that can be used as fuels. Various categories of wood waste have been proposed for consideration. We will talk more about what CIBO will do during the Energy/Technical Session at the Annual Meeting.

GOVERNMENT AFFAIRS SESSION

Anthony Reed, Archer Daniels Midland Company**,** *Government Affairs Committee Chairman*

There will be a briefing Wednesday afternoon at the Environmental and Public Works hearing room on the results of the IHS Global Insight study on the potential for job losses associated with Industrial Boiler MACT. A number of industrial organizations will also provide testimonials on the topic. The study made use of the IMPLAN model, which is widely accepted for this type work. The model estimates the direct, indirect, and induced impacts on the economy and job creation. Three scenarios were studied. The first scenario was the implementation of the rule as proposed. The second scenario analyzed the potential for using a health based compliance alternative. The third scenario analyzed the impact of implementing a more stringent proposal for natural gas units. The basic result is that for every $1 billion spent on this rule, 16,000 jobs are at risk, as well as a GDP reduction of $1.2 billion. The tax implications were also estimated.

The biggest impacts come from the indirect effects in the supplier industries. The EPA cost estimate for scenario one was $9.5 billion, based upon the EPA Control Cost Book of 1998. More up to date cost figures would put the cost of this scenario at $20.7 billion. This figure is still relatively low as most of the data was based on reports from 2003. Further, the units have to meet the standards over the entire load range rather than just the full load snap shot of a stack test. The total number of jobs at risk was estimated to be 337,700. Roughly half of the job losses came from indirect impacts. Scenario two demonstrates the value of the flexibility of having a health based compliance alternative (HBCA). The number of job losses can be reduced by nearly half with the application of HBCA. Scenario three demonstrated that the work practice standard approach as proposed by EPA for natural gas (Gas 1) was far superior to developing detailed standards approach with individual pollutant limits for natural gas fired units. In this scenario, the costs were estimated to be $51.5 billion, resulting in potential job losses of 800,000.

ENVIRONMENTAL COMMITTEE SESSION

Maxine D. Dewbury, The Procter & Gamble Company, *Environmental Committee Chairman*
Rob Kaufmann, Koch Companies *Public* Sector, LLC, *Environmental Committee, Vice-Chairman*

Maxine had some comments to the June minutes. These will be incorporated. There are now two litigation charts due to the additional activities in GHG litigation. There is also a comments and documents chart.

Litigation Update - **Lisa Jaeger**, Bracewell & Giuliani, LLP

Lisa noted that the next deadline for comments is on the Clean Air Transport Rule, which are due Oct. 1, 2010. The next one that will be due is the Coal Combustion Byproducts proposed rule making, which is due Nov. 19, 2010. Comments are also planned for the Environmental Justice guidance that was recently issued. Since this is "guidance", there is no deadline for comments. The revised NSPS will be coming up shortly. The basic standards were remanded. The CO2 issue was remanded. There is the potential that EPA could try to put both together. EPA issued a FIP for GHG regulations. States are unhappy with the FIP. There might be another need for comments for this issue.

Another round on the ozone NAAQS is expected by November. On the litigation side, the Hospital/Medical/Infectious Waste Incinerator (HMIWI) rule is being litigated under a suit filed by the Medical Waste Institute against EPA. Final Briefs were filed on Sept. 17. Oral arguments will likely be held in January with a decision probably by next May. CIBO participated in a coalition that provided an amicus brief as there are some precedents in the HMIWI rule that are also in the Industrial Boiler MACT that needed comments. The Portland Cement case also precedes the Boiler MACT. There may be a need for comments in that case as well.

On the NSPS case, New York filed suit against EPA in 2006. EPA took a voluntary remand in 2009 with the change of administration. The CO2 issue was brought up by the environmental groups. This was severed by the courts and remanded to EPA. The environmental groups have demanded that

EPA issue standards for a CO2 NSPS by Sept. 15th. They are threatening court action. They also want a schedule for non-EGUs.

The ozone NAAQS started with a law suit filed by the state of Mississippi in 2008. Again EPA took a voluntary remand and partial stay with the change of administration. The states that supported a stricter rule several years ago are now upset that the more stringent rule will cause too many non attainment areas. The EPA had originally set a date for the end of August. They subsequently announced that the date would be on or about the end of October. Most recently, they have just stated November, 2010. It is not likely that the election being the first week in November and the delay are just a coincidence.

On the SO2 NAAQS, a petition was filed in August. The major issue will be the reliance on modeling vs. reliance on monitoring. Right now, a number of industrial organizations are participating.

The CEM Rule revision was initiated by Air Liquide. This rule required that calibration gases be purchased from suppliers that comply with the protocol gas verification program. However, EPA did not publish a protocol gas verification program. Settlement proceedings are ongoing. On Greenhouse Gas Regulation, the Johnson Memo was issued to clarify that reporting of GHG emissions was not "regulation under the CAA" and therefore a CO2 BACT determination was not needed before GHGs become regulated beginning January 2, 2011. The GHG reporting rule has been challenged by a number of parties. EPA is attempting to resolve the petitions for reconsideration one by one. The endangerment finding has nearly everybody suing EPA, including members of Congress and states. Defenders include EPA and a number of states, as well as the usual environmental groups (Sierra Club, EDF, NRDC, and others). The PSD Interpretive Memo Rule (i.e. the Johnson Memo) adopted the same position as the Bush Administration. The Light Duty Vehicle Rule was also issued, which would make CO2 a regulated pollutant. These two rules are interrelated. There have been requests to consolidate and coordinate these cases. The EPA and eNGOs are against this consolidation. There are also activities in Congress that attempt to slow down the EPA process (notably the Rockefeller proposed amendments to the energy bill). At the moment, all is up in the air.

Boiler MACT Comments and Advocacy - **John deRuyter**, E.I. DuPont de Nemours & Company

John pointed out that a very good presentation was given by Bob Fraser of AECOM at the IECT VIII Conference in Portland, Maine that was a "tongue in cheek" nightmare scenario on the concept of cherry picking the best of the best results from different units.

There are four interrelated combustion rules. These include the definition of solid waste, the Industrial Boiler/Process Heater Major Source MACT, the ICI Boiler Area Source MACT, and the Commercial and Industrial Solid Waste Incinerator (CISWI) rules. All four of these rules are scheduled for final promulgation by December 16, 2010. This is not really enough time to review the thousands of comments that are being submitted. The first issue is the definition of solid waste, because this determines whether a unit is a boiler or an incinerator. This issue was the one that caused the vacatur in the first place. Issues include the classification of secondary materials as waste when burned outside of the control of the generator, differing ownership structures in industry, processing issues, and historically combusted fuels.

The work practice approach for natural gas is a good idea that should be extended to other gaseous fuels and distillate fuels. The tune up requirements have some problems including the words "minimize CO" which would encourage the use of higher excess air and thus lower efficiency and more GHG emissions. Internal experts should be allowed for audits. Energy consuming systems are outside of the EPA authority. EPA cannot compel investments. Sources should be limited to those affected under the rule. Rather than requiring the Energy Star program, allow other audit systems.

The achievability of the limits presents a problem as the floors are determined on a pollutant by pollutant basis. This approach makes it difficult to find any units that can meet all of the limits simultaneously. Non representative units were used to establish some of the limits. There was not enough consideration of variability in MACT floors. Dioxin and furan limits were driven by one or two units that measured below detection limits. There was very little liquid data overall. A better statistical approach is needed given that the data set does not represent the diverse population of units and fuels. Industrial sources must have assurance of their ability to meet emission limits routinely. These sources must be able to meet the limits with available fuels and controls.

The start up, shut down, and malfunction (SSM) issue is not handled properly. The 30 day average was stated to "cover" start up and shut down. The EPA stated that top performers should not have any malfunctions. There was no data to demonstrate this claim. Risk based provisions are allowed under the act (Section 112(d)(4)). This should be applied to HCl.

EPA estimated the cost at $9.5 billion. The industry estimate is $20 billion. If Gas 1 limits would be imposed as discussed in the preamble, another $8 billion for the chemical industry would be required assuming that controls would be effective (and $50 billion overall).

The Area Source Rule suffers from some of the same problems. The emission limits are unachievable. The oil fired limit is 2 ppm CO for existing boilers and 1 ppm for new units. The energy assessment is too broad. The SSM issue is the same.

The CISWI rule has problems that impact boilers. There needs to be more subcategories. Energy recovery units (i.e. boilers firing solid waste) need to be broken down by fuel. A gas or oil fired unit that burns some waste oil will not have the same emission levels as a waste coal fired unit co-firing biomass or pet coke. Burn off ovens and laboratory analysis units should retain their exemptions. For example, a bomb calorimeter in a lab at an industrial site would be classified as an incinerator under the proposed rules.

URS and AF&PA worked over the EPA database to estimate the cost of controls needed to attempt to meet the limits. These include scrubbers (chlorides), baghouses (particulates), carbon injection (mercury and dioxins), and CO catalyst (for CO). For each unit in the database, a determination was made as to what controls already existed for a given unit. Costs were obtained for a 250 MMBTU/hr unit and scaled accordingly for the different sizes. This lead to the $20 billion estimate. Each unit has a NAICS code so that the economic sector for each unit is known. From this data, IHS Global Insights was hired to estimate the impact on job losses in the US. The number was estimated to be 337,000 job losses, or 16,000 jobs per $1 billion spent. If the Gas 1 limits were imposed, the number of job losses would exceed 800,000. This report will be released to Congress on Wednesday. The goal is to make Boiler MACT a workable rule (i.e. more like the rule that was vacated).

RCRA Ash - **Gary Merritt**, Inter-Power/AhlCon Partners, L.P.

EPA proposed a rule on coal ash classification that requested comments on 2 (at least) different approaches. The proposal is in 4 different parts. These would be sub title C (hazardous waste), sub title C special waste (includes exemptions), sub title D (non hazardous waste), and sub title D with special provisions. There is also special category under sub title D. The rest of the government agencies are against treating coal ash as a hazardous waste (i.e. sub title C). There is also a D prime classification which would have a major impact on impoundments. There needs to be a provision for beneficial use. One of the key issues is "federal enforcement". Under sub title C, EPA has enforcement capability. Under a "D" approach, EPA claims it has no enforcement capability. However, there is the potential to claim that the site could be classified as an "open dump" under which EPA would have enforcement capability.

The rule is intended to apply to electric generating units. However, sub title D does not have exemptions so that a D classification could conceivably pick up all coal fired units. The basic comment is that CCRs need to be regulated under sub title D and not sub title C. The rule must be clear regarding exclusions or applicability. It is not likely that industrial units will be exempted as the states typically regulate all coal ash facilities in a similar manner. By excluding industrials in the EPA rule, their analysis of the impacts is less. Meanwhile the industrial units get captured by default. Coal ash does not show up as a hazardous waste by normal testing (leaching analysis, TCLP, SPLP, etc.). If a material does test positive, it is already treated as a hazardous waste.

The performance standards proposed by EPA are essentially the same for either sub title C or sub title D. The big difference is that under C, there are additional requirements as well as the negative aspects associated with "hazardous waste". Personnel safety requirements, hazardous waste management, insurance requirements, etc. will be impacted all through the power plant. EPA has dismissed the "stigma issue" with respect to beneficial use. However, the Office of Surface Mining has reported to EPA that the classification of coal ash as a hazardous waste would put such a stigma onto coal ash that beneficial uses would essentially be eliminated.

EPA has other authorities besides RCRA, including drinking water rules and NPDES. The performance standards include impoundment standards, monitoring standards, etc. The monitoring system could trigger the need for an assessment, which could lead to a remediation plan and perhaps a plan implementation. Setting the trigger levels would be critical. There are closure and post closure requirements. This is typically long term monitoring (10 years or longer). EPA has stated that they will look at all comments. The environmental groups have organized mass mailing and e-mailing to flood the agency with form letter comments. The industry is starting to set up similar activities.

NAAQS - **Rob Kaufmann**, Koch Companies Public Sector, LLC

Regional Haze is back on the radar. There are 37 states that failed to file adequate SIP updates. The environmental groups have told EPA that they will sue to force EPA to issue a FIP to force BART retrofits on existing units. EPA is still on schedule to issue a new PM2.5 NAAQS standard early next year. This standard is likely to contain a secondary standard to address regional haze. This has been supported by staff and CASAC. Several senators have written letters against. PM10 is back. The old standard is 150 micrograms/m3. EPA is proposing 65 - 85 micrograms. CASAC is suggesting 65 - 75 micrograms. For PM 2.5, the 24 hour standard is currently 35 micrograms/m3. EPA is proposing 30 micrograms/m3. This is close to background levels. Modeling will be required to demonstrate compliance. This will get more difficult.

The ozone NAAQS will be delayed, most likely until after the elections. The current standard is 75 ppb. EPA was considering 60 - 70 ppb. There have been a lot of comments submitted, including bi-partisan senatorial letters. An anti back sliding rule is being proposed in response to court order.

On the SO2 NAAQS, EPA has been sued by the utilities and NEDA. The utilities claim that EPA lacks the scientific basis for introducing the 1 hour standard at 75 ppb. The main issue is that EPA is insisting that modeling has to be done to demonstrated compliance rather than monitoring. There is already a state law suit against EPA for a case where the monitors showed compliance, but the models showed non-compliance. The modeling problem is further complicated by the fact that EPA has not issued any guidance for doing the modeling. Without guidance, the states often "pass the buck" to the regional EPA office. The regional office then sits on the application, which further delays the process and drives up the cost. At the end of August, a temporary, interim guidance for SO2 was issued. For those situations where BACT does not model out, the EPA suggests that controls beyond BACT can be used, followed by purchasing offsets, the impact of which can be modeled until the NAAQS level is reached at the fence line. EPA, ECOS, and NACAA have formed a working group to "improve" the SIP process. A number of suggestions were made to attempt to "streamline" the process.

Clean Air Transport Rule (**CATR) Update** - **Rob Kaufmann**, Koch Companies Public Sector, LLC

Comments are due Oct.1, 2010. Utilities, IPPs, and large cogenerators have commented that the IPC model used to project utilization of emission units in the future are suspect. This could impact the number of allowances that would be issued. The current rule is only for EGUs. There is intended to be a second round. Several environmental groups have testified at public hearings that industrial units should be included in the second round. EPA is likely to agree. There is an exemption for cogenerators. However, EPA is taking comments on eliminating that exemption. There also appears to be a major records requirement to qualify for the exemption. EPA has requested records going back to November of 1990 to demonstrate that the unit has operated as a cogenerator every year. There is a methodology to determine if an upwind state is contributing to non-attainment of a downwind state. The cost effective threshold for this round was based on the 1997 NAAQS. The NOx threshold was $500/ton. In the next round, the EPA will attempt to bring the rule up to the latest level of the NAAQS. The EPA anticipates that each time the NAAQS are changed a new round of tightened Transport Rules will be needed. More recent estimates from the regional entities are in the $2,000 - 7,500/ton range. For small units the costs tend to be higher.

Protocol Gases - **John deRuyter**, E.I. DuPont de Nemours & Company

A final rule was issued on Monday for the supply of audit samples for gases from approved suppliers rather than from EPA. These apply to SO2, NOx, TRS, HCl, and others. The EPA has established some new sources for these samples. Instrumental methods are exempt. This applies to samples that are taken and sent to an independent laboratory. An audit sample must be sent along with the actual samples. The rule goes into effect in 30 days. In the preamble, it states that if an audit sample is not available, the requirement is waived. The EPA web site will post the suppliers.

GHG Regulations - **Rob Kaufmann**, Koch Companies Public Sector, LLC

On Jan. 2, 2011, PSD for GHG comes into effect. If a PSD permit has not been issued for a project before that time, then a PSD determination has to be made for GHGs. There are 13 states that are required to issue SIP calls for GHG regulation (including CT). If they don't meet the January deadline, EPA will issue a FIP. A PSD permit would require BACT for GHGs. These states have listed the PSD pollutants by name in their SIPs and GHGs are not listed. If there is no reference, the state can defer to EPA's interpretation. Without an approved SIP, a state may be stuck with the 100/250 ton threshold for PSD.

There is a CAAAC work group that is advising EPA on implementing the PSD provisions for GHGs. The CAAACis reviewing a preliminary report. EPA has been charging along in the interim. A top down BACT guidance document is going to OMB shortly in an effort to get something out before Jan. 2, 2011. A second approach has been to provide guidance to individual sectors including industrial boilers, cement, refineries, pulp and paper, iron and steel, and others. These second documents will not be available for public comment. The work group produced some consensus recommendations and some unresolved issues. The only "end of pipe" control technology that was identified was carbon capture and sequestration (CCS). This technology was not deemed to be commercially available at this time. That left energy efficiency improvements as the only technology based "control" that could be applied. The sector specific guidance will suggest that states look globally for ideas for energy efficiency improvements.

There are also Energy Star program guidelines for energy efficiency for various sectors. Under that program the following options can be considered:

- advanced controls
- combustion optimization
- flue gas quantity reduction
- low excess air
- condensate returns
- condensate or blowdown heat recovery
- reduced blowdown requirements

Presumably, a state that has to approve a PSD permit for GHGs would require the project to address these options in their permit request to demonstrate that energy efficiency is the "best available". One of the unresolved issues was the scope of the efficiency rule. This means that the efficiency boundary could be drawn around the boiler, or around the boiler and steam system, or around the whole plant. The environmental groups want the standard to apply to the whole plant. The second issue is whether fuel switching represents BACT. Here a coal fired unit could be required to switch to natural gas as BACT for GHGs. Another problem is the cost threshold for BACT. If the current levels of SO_2 and NO_x thresholds at \$2000 - 8000/ton, then almost any control project could be required, in spite of the fact that CO_2 allowances are on the order of \$20 - 30/ton. The work group has not talked about netting.

Next, Technical Focus Group/Environmental & Energy Committee Meetings

TUESDAY & WEDNESDAY, DECEMBER 7-8, 2010

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