May 23 - 25, 2011
Hershey, PA

I. Owner's Equipment and Service Suppliers' Only Forums - **Joe Gonzales**, Bibb Engineering, Architects & Constructors

The Equipment panel included **Bill Campbell**, AECOM, **Hamilton Walker,** Allied Environmental Solutions, Inc., and **Bob Deneault**, Metso Power & Automation. The Owner's panel included **Robin Ridgway**, Purdue University and **Gary Anderson**, A/C Power Colver.

II. Review of Concurrent Forum Discussions - **Lou Gonzales**, Bibb & Assoc.

The Owner's discussion indicated that half of the owners might fall under Utility Boiler MACT and half might fall under Industrial Boiler MACT. **Don Frey,** ADM, pointed out that alternative fuels have attracted more interest. Concerns include unburned carbon (LOI), NOx and SO2 emissions, and maintaining bed temperature. Fouling issues arise when low melting contaminants are introduced with the fuel. Robin discussed some of the emissions issues. Mercury and HCl are part of both MACT rules. Trying to understand the fuel quality is important. It is not possible to contact the coal factory and dial in the chloride or mercury content of the coal.

A PM CEMs is required for units over 250,000 lb/hr steam flow. These are expensive and are not useful for control of the particulate control equipment. Waste coals have a lot of variability, particularly with respect to mercury and chlorides. **Arun Mahabirsingh,** Air Products, noted that bed temperature control has been an issue at their plant. Air splits, bed level, and ash reinjection have all been used. Biomass (fruit pits) has been used for fuel due to their location in California. Agglomeration has been an issue. Screened bottom ash from another unit was used, which helped in the control of bed temperature but was very erosive. Sand injection is being considered. Kaolin has been another consideration.

Questions from the supplier group included the MACT compliance strategy and the owner's response to the stay, as well as the overall regulatory compliance situation for solid fuel units. Older units are not being replaced with new solid fueled equivalents. No new units were underway by the owner's in the audience. The universities are being pushed away from coal. The environmental groups are using the Freedom of Information Act to pry into plans of the universities to find out what they are doing.

Some owners that have CFBs are looking at biomass co-firing, but supply concerns and environmental permits, as well as public opposition (" burning up our forests") have made that option difficult. Fuel flexibility is a big issue as a permit issue. Units that convert to gas will not likely be able to go back to coal (either because of permits or because the equipment will be removed). One CFB is co-firing natural gas. At lower loads, gas can be co-fired at a relatively modest cost to create a very low emissions unit. When full load is needed, the unit can come up on coal all the way to full load on coal. The potential for cogeneration is dependent on location. In states with regulated utilities, the prices offered for cogenerated power tend to be low. Some areas that have high power costs can benefit from cogeneration. Most of these opportunities result from the use of back pressure turbines to recover energy from high pressure steam.

III. Overview of Air Permitting Issues - **Russell Bailey**, Trinity Consultants

Russell pointed out that the last time he presented at the FBC Conference was in 2006. The permitting and energy landscape has changed very dramatically. In 2006, natural gas prices were high. Coal was making a comeback. The economy was doing well. The EPA leadership was attempting to provide reasonable, or achievable, regulations. Today, natural gas prices are down. Coal is being forced out. The economy is weak. The EPA is trying to regulate wherever it can. EPA determined coal combustion residuals (CCR) to be non-hazardous in 1988, 1993, 1999, 2000, and 2005. This EPA is taking another run at CCR, but the rule has been delayed. The cooling water issue is another example of EPA activity. This rule could have a larger impact than the air regulations.

The Clean Air Act requires the ambient air quality standards to be reviewed every 5 years. This requirement has generally not been met until this current EPA administration. EPA's implementation of each new 1 hour standard is causing challenges. Predicting 1 hour standards under all weather conditions is a major modeling challenge. The Transport Rule (CATR) is a replacement for the CAIR rule that was vacated by the courts. The rule was proposed in July 2010 and is expected to be signed by summer 2011. The EPA has already opened Regulation Identifier Numbers for a new Transport Rule to update expected 2011 ozone and PM2.5 revisions. This rule is expected to come out right after the new NAAQS are finalized.

Section 112 of the CAA requires Maximum Achievable Control Technology ( MACT) for the control of Hazardous Air Pollutants (HAP). The Industrial Boiler MACT was issued on March 21st, but has been stayed by the EPA due to the number of comments that have been received. In addition to the Boiler MACT, additional rules include the definition of solid waste, incinerator rules (CISWI), and Area Source MACT (for small boiler sources). Trying to determine which HAP program a source falls under is a challenge.

On the Greenhouse Gas (GHG) rules, some of the rules have changed some of the deadlines. The EPA has a new electronic reporting tool which will be ready for testing in June. Several states, local governments, and environmental organizations have sued the EPA over its failure to update pollution standards for power plants and refineries. In December, EPA issued a time line for issuing New Source Performance Standards for GHGs. The Tailoring rule was finalized last June. This rule provided guidelines for when PSD permitting would be triggered including construction of a new facility, major expansion of a facility, and significant modification of an existing facility. With this rule, the traditional major source criteria of 100 ton/yr of any regulated pollutant or 250 ton/yr of any combination of regulated pollutants does not apply. After July 1st, a source that emits more than 100,000 ton/yr of GHGs and makes a modification that causes an increase of more than 75,000 ton/yr of GHG will trigger the need for a PSD permit. Thus, a unit that improves its dispatch position on the grid (say by implementing a steam turbine upgrade), and thus has the potential to operate more hours per year, will trigger PSD requirements for GHGs.

IV. FBC Owners' Survey Results - **Jack Fuller**, West Virginia University and **Gary Anderson**, A/C Power Colver

The results from the 2010 FBC owners' survey were presented. The raw data is only available to the survey team. Detailed boiler and fuel information are requested. Efficiency, performance data, and emissions data are requested as well as outage and availability data. The owners were also asked to identify their concerns for 2011. A total of 16 plants responded to the survey including 25 boilers. Of these, 7 were less than 40 Mw net.

Primary fuel sources include 8 coal plants, 4 gob plants, 1 wood plant, and 2 petcoke plants. Secondary fuels include biomass, RDF, wood, and petcoke at 4 plants. Of the 25 boilers, 21 were CFBs and 4 were BFBs. Roughly 44% of the flyash was used for beneficial purposes. About 56% of the bottom ash was used for beneficial purposes. Twenty of the 25 boilers made use of their ash. Some 41% of the facilities are addressing concerns for mercury due to the Industrial Boiler MACT. Some units are relatively low emitters, but have the problem of how to prove they are low emitters. One plant emits only 2 lb of mercury per year. They had to modify their testing procedures to be able to routinely demonstrate their compliance.

Plant availability for gob, coal, and overall ranged from 90 - 95%. The gob plants continued to show higher availability. Since these plants are typically used in qualified facilities, their economics are more dependent upon plant availability leading to stronger maintenance practices. Forced outages due to fuel were examined by fuel type over the past 6 years and appeared to be fairly random. There does not seem to be any fuel pattern. For 2010, the numbers were about 20% for all fuels. Unit age was also considered. Again, no particular trend was found. Boiler related outages represented 80% of the total outage hours. In 2010, about 20% of the forced outages were turbine/electrical related, 19% were pressure parts related, 14% were back pass pressure parts related, and ash handling and fuel handling were 4% and 3% respectively.

Owners' concerns were highest for ash regulations, ash disposal, fuel quality, tube erosion, and NSR definition changes. Refractory, cyclones, and fuel feeding were of relatively low concern.

V. DOE/NETL - GHG and Alternative Fuels - **Bob Romanowsky**, DOE NETL

The Advanced Power Systems group in DOE Fossil Energy works in synergy with other programs to increase power plant efficiency, lower cost of energy, and mitigate GHGs. The Advanced Program has a 15-25 year horizon for technology that supports breakthrough concepts. These include advanced materials, sensors and controls, modeling and simulations, and university coal research.

In advanced ultra-supercritical boiler technology, steam temperatures up to 760 C and pressures over 5000 psi are being investigated along with oxygen firing. Key research areas for GHG include post combustion capture, oxy combustion, chemical looping combustion, and advanced $CO_2$ compression. Goals include commercial deployment of post combustion and oxy combustion systems by 2020.

Oxygen fired CFBs with some biomass firing has the potential to achieve a "negative" $CO_2$ footprint. The oxy fired CFB is smaller and does not need an SCR for $NO_x$. The DOE likes the idea of "co- sequestration" of $CO_2$ along with $SO_2$/$NO_x$ (i.e. flue gas sequestration). On the IGCC side, hydrogen turbine development is being supported along with component improvements. There is also a fuel cell program with the idea of combining the fuel cell with IGCC to achieve power plant efficiencies over 60%.

As there are 6.3 billion tons/year of $CO_2$ emissions, we cannot use all of the $CO_2$. Therefore, sequestration will be required. DOE has a sequestration program with 7 regional partnerships doing test sequestration wells. The US has substantial storage capability in saline aquifers (up to 400 years). DOE has recently reviewed its cost assumptions on power plants. They have concluded that a supercritical CFB with oxygen firing and 30% biomass have a negative $CO_2$ footprint at reasonable costs. These systems compare favorably with natural gas combined cycle systems. Chemical looping is being proposed as a potential product for the industrial boiler market. There are a lot of smaller boilers that could utilize the chemical looping system and avoid the need for post combustion $CO_2$ capture. The demands for cost effective energy systems that satisfy environmental requirements are increasing and innovative systems will be required.

Errors in the EPA calculations have been identified for mercury emissions and some other compounds. The EPA missed the conversion from lb/trillion BTU into lb/Gwhr by a factor of 1000. In May, EPA responded with a proposed change by a factor of 20. The DOE has gone back to EPA requesting the other factor of 50 times.

VI. Regulatory Issues That Impact FBC Technologies - Panel

The panel consisted of **Vince Brisini,** Leonardo Technologies, **Bill Campbell** , AECOM, **Russell Bailey**, Trinity Consultants, Inc., and **Terry Black**, ERM.

**Vince Brisini,** Leonardo Technologies, talked about the impact of the Boiler MACT rules. The problem is which rule does the fluid bed fall under? If the unit produces more than 25 Mw of electricity and sells 1/3 of that power to the grid, the unit falls under Utility Boiler MACT. If the unit burns any waste material, the unit falls under the CISWI rules. If the unit is not one of those, it would fall under the Industrial Boiler MACT rules. The next qualifier is whether the source is a major or a minor source. Minor sources will fall under the Area Source MACT. Major sources remain under the Industrial Boiler MACT. Major source limits are broken down into coal or biomass units that are new or existing and are either fluid beds, stokers, or PC units. Area sources are broken down into coal and biomass with units greater than 10 MMBTU/hr or less than 10 MMBTU/hr. Existing units under the Area Source rule generally have no numeric limits. The revised, proposed rule was published in the Federal Register on March 21, 2011 with a 3 year compliance date.

The EPA also published a proposal to reconsider the rule. On May 18th, the EPA issued a stay of the rule. The effective date is delayed until judicial review is no longer pending or until EPA completes its reconsideration. This stay applies to both Boiler MACT and CISWI. EPA has requested additional comments by July 15$^{th}$. This is not necessarily a cut-off date, but a request.

The Utility MACT rule was posted in the Federal Register on May 3, 2011. This regulation is to be finalized by Nov. 16, 2011. However, in the settlement on this rule, EPA can take more time if needed. The comment period is 60 days. The 8300 BTU/lb line of demarcation is on a moisture and ash free basis. For units with a fuel greater than 8300 BTU/lb, the mercury standard has been revised to 1.2 lb/trillion BTU or 0.013 lb/Gwhr for existing units. For units with a fuel less than 8300 BTU/lb, the mercury standard remains at 11 lb/trillion BTU or 4.0 lb/Gwhr. For new units, the standard has been revised to 0.0002 lb/Gwhr, which still suffers from a calculation error. Mercury monitors are not able to measure levels reliably at these levels. The sample system is a problem. This might preclude continuous emission monitoring systems.

The sub categorization with only two levels will likely make some coals unmarketable in the US. There are no boiler sub-categories. Thus, a CFB with a baghouse typically gets fairly good mercury capture. These units will set the MACT floor. Other units with other fuels will have to meet that limit regardless of fuel type or boiler type. The timing will be a problem as permit times will lengthen making it difficult to start purchasing equipment until the permit is finalized, which limits the remaining time to meet the standard. Implementation and record keeping with add to burden of demonstrating compliance. The general compliance issue states that the system must operate to minimize emissions at all times, not just meet the limits. Affirmative defense will apply for malfunctions. These problems are those that could not have been prevented by better planning and maintenance practices. The Transport Rule only applies if you are an electric generating unit (EGU) in the Eastern US. The SO2 NAAQS will impact units in complex terrain. These units will need extensive modeling. Pennsylvania is discussing re-RACT. This might lower the limits for Reasonably Achievable Control Technology.

**Bill Campbell,** AECOM , reported on the impacts of the new NAAQS limits. There are new standards for NOx, SO2, and PM2.5. The one hour standard has significant impact levels down to 8 micrograms/m3 for SO2. This is lower by a factor of 9. Similarly NOx is down by a factor of 7. The ozone standards will be finalized by July 2011. There is another round planned shortly thereafter. The CO standard is expected by August 2011. The SO2 standard has been completed. PSD permitting after August 2010 must utilize the one hour standard. Modeling for the SO2 standard is a challenge. Under the new proposal, areas that fail either monitors or modeling can be designated as non- attainment areas. Areas that do not have adequate monitors and are un-designated must demonstrate their status by 2014. The NOx standard has also completed review. With a 1 hour standard, the issues start to pick up start ups, shut downs, and malfunctions. The major contributors are vehicles and highways. EPA is pushing for monitors within 50 meters of roadways for all cities with populations greater than 200,000. The PM2.5 tends to be more of a local site issue compared to SO2 and NOx.

There are two major models approved by EPA (AERMOD f and CALPUFF). The models have been set up to be ultra conservative. For areas with a high background concentration, there is not much room between background and the standard. For rough terrain areas, the model will greatly over predict. The assumption of worst conditions with highest emission rates at all times will cause the model to over predict substantially. Modeling in the future is going to be very expensive and very detailed. These models tend to over predict at low wind speeds. Smaller sources with short stacks (including gas fired units) will have difficulty.

Sources that are required to model startup/shutdown/maintenance issues may not be able to demonstrate compliance under certain scenarios. Emergency generators can be a problem due to short stacks and low wind speeds (ie at night). One possible help is that emissions conditions that are not in effect more than 3 days/yr can be exempted. The EPA has issued a guidance document, but this only covers the first step (screening). When background monitoring data is impacted by a large source, multiple monitoring sources can be of some help. If the high background can be attributed to a particular source, that level can be reduced so as not to count it twice for the new unit being considered. With the lowered significant impact limits (SILs) for all 3 pollutants, it is not likely that extensive modeling can be avoided. Owners of existing units should begin to develop an understanding of ambient impact of their sites. Preliminary modeling should be considered. Critical information gaps should be identified. From there, potential strategies to demonstrate compliance can then be considered.

**Russell Bailey**, Trinity, reported on GHG PSD/NSR implications. For those with minor NSR permits, get these completed by July 1, 2011. After July 1, GHG PSD requirements will apply.

The first issue is the “potential to emit”. Average efficiency and 100% capacity factor are used. Although CO2 is the prime factor, GHG equivalents must be considered (CH4, N2O, etc.). With the Tailoring Rule, 100,000 ton/yr is the threshold limit (i.e. a little over 190,000 lb/hr steam flow). For these units, changes or modifications that would result in an increase of 75,000 ton/yr of GHGs would trigger NSR. As an example, a paper mill was looking to add a new paper machine along with a new gas fired boiler at 150,000 lb/hr. If the plant was already a major source, the addition of the new gas fired boiler would trigger a PSD requirement for GHGs. Now the source is a major source and could trigger considerations for other pollutants (ie VOC and NOx in this case). Another consideration could be changes in capacity factor. If some coal units are retired and some gas fired units will run more often (at another site), the gas units might run into a GHG PSD requirement due to their now higher potential to emit.

Once GHG requirements are triggered, top down BACT must now be applied. Now the installation of economizers, air heaters, plant controls, burner systems, etc. are potential control technologies. These options now must be ranked (from highest reduction levels to lowest). In the case of the paper mill, installation of an economizer, an advanced burner system, increased insulation, and good maintenance practices were required. This was translated to achieving an 85% boiler efficiency (on natural gas) and then further translated to a lb/MMBTU limit for CO2.

Another problem will be that environmental NGOs will now look at world wide data on efficiencies. One steel plant requested a permit with 13 decatherms of natural gas per ton of steel for a new process. The NGOs fought the permit on the grounds that there were other plants in the world that made steel using only 10 decatherms/ton (regardless of the type of process).

**Terry Black**, ERM, reported on the issue of waste vs. fuel. The suite of rules just issued includes MACT, GACT, CISWI, and solid waste definition. MACT applies to fuel burning sources. CISWI applies to waste burning sources. Coal, oil, natural gas and "traditional" alternative fuels (i.e. clean cellulosic biomass) are fuels. Units that burn any amount of waste are subject to CISWI. These units have regulations for 10 compounds rather than 5 with more CEMS and more reporting requirements. The rule does not assume that biomass is always a fuel. The rule does not prescribe which materials are a solid waste. There are legitimacy criteria as well as a process to get a determination if a material is a waste or a fuel. Recent coal refuse is considered an alternative traditional fuel. Material from a legacy coal pile is considered a waste and must be "processed" in order to become a fuel. Certain materials are identified as wastes including animal manures, mixed demolition wastes, pressure treated woods, legacy coal piles, and off spec used oil. Industrial by products obtained from a 3$^{rd}$ party are considered wastes. Waste materials can be reclassified by appropriate processing or by petitioning the EPA. The first step will be to determine which rule applies to your fuel (waste). Once the determination has been made, the potential emissions limits need to be identified and subsequently a compliance strategy must be developed. Additional comments are due by June 20th.

VII. Panel Discussion on Alternative Fuels - **Carl Bozzuto**, Alstom Power Inc., Moderator

The panel members included **Don Frey**, ADM, **Peter Kline**, Evergreen Community Power, and **Lou Gonzales**, Bibb Engineers Architects & Constructors.
ADM has a number of CFBs and utilizes a number of " biomass " fuels including tires, railroad ties, pallets, seed corn, and soybeans. Securing sufficient quantities of alternative fuels is a challenge. Bibb Engineering & Associates has worked extensively on waste coal projects and has experience on a wide variety of fuels. Evergreen Power has a plant in Reading, PA that supplies power to a corrugated paper mill. They burn paper mill sludge, bark, and clean, sorted construction debris. Question topics from the floor included the percentage of biomass co-firing, MSW, petcoke and biomass, sources and ranges, pelletizing, torrefaction, handling issues, and silviculture. The old rule of thumb about 10% biomass to be co-fired with coal came about from avoiding changing the chemical content of the ash in any significant way. Levels higher than that are possible with appropriate fuel analysis and design considerations. Alkalis, chlorides, and moisture content are all issues impacting the amount of alternative fuels that can be co- fired. There are on the order of 100 Municipal Solid Waste (MSW) plants in the US. They are classified as incinerators. It has been difficult to get more of these plants permitted, partly due to the usual NIMBY issues and partly due to the difficulty of getting so many cities and towns to agree to the costs and regulations to be followed.

There was one attendee that was firing petcoke and biomass (80/20). Sources are typically considered in the range of 50 miles radius for 50 Mw and 100 miles radius for 100 Mw. There are fuel supply consultants that can help find sources. Torrefication and pelletizing are being developed to overcome some of the handling and shipping issues. Decay and rot of biomass in storage and handling can be a problem. The deliberate growth of trees or grasses to use directly for fuel has not taken off. High costs have been reported as the problem.

VIII. Tube Leaks and Air Leaks - **John Malloy**, A/C Power Colver

**Jeff Campbell** of the Scrubgrass plant, has 2 x 380 kpph boilers of 1993 vintage. These units run well, but have refractory ledges where they get erosion. Proposed solutions include kickout tubes, widened ledges, crisp horizontal surfaces, raised refractories, metal sprays, and weld overlay. While the kickouts address the source of the problem, there can be issues with pressure part modifications. The exact mechanism of the erosion has been speculated upon.

Grove City University was contacted about doing a plexiglass model. The scale was 1:6. Cork was used for the solids. Full size tubes were used. Visual observation of the tubing showed that the ash built up on the ledge to the angle of repose. As additional solids built up, from time to time a slug of ash fell away wearing out the 2 o'clock and 10 o'clock positions. Specially designed tiles were used to convert the ledge into a steep slope. The amount of erosion and the severity erosion was greatly reduced in the first 9 months of operation with the tiles. Roughly 1/3 of the tubes show any signs of wearing out the metal spray. Of those, a few started to show some tube erosion. The wider ledge helps the problem due to the fact that the ash can build up to a larger distance. This spreads out the ash washing over a larger length of the tube. The crisp edge helps by cutting down the variability in the size of the slope, which affects the stability of the slope. These conditions tend to reduce the severity of the ash erosion.

**Chris Henderson**, JMP Engineering, reported on air flow measurements and controls. One of the major control aspects of the CFB is the control of bed temperature. Units with external heat exchangers have independent control of the bed temperature. For those units without an Fluidized Bed Heat Exchanger (FBHE), FGR or air flow changes can impact the bed temperature. Good emissions control and efficient combustion are dependant upon creating a stabile combustion environment. The bed temperature impacts the NOx formation, the SO2 absorption, the combustion efficiency, the CO level, and any unburned emissions. “Consumed Air Control” utilizes the boiler as a real time calorimeter to calculate the real time heat release in the boiler. Knowing the oxygen concentration in the flue gas and correcting from the oxygen concentration in air, one can calculate the amount of air that was consumed. The heat release per pound of air is relatively constant for most hydrocarbon fuels. Knowing the amount of air consumed thus determines the amount of fuel burned. The steam flow is related to the heat release. This system can be implemented in the DCS system.

**Dave Marut**, Midwesco Filter Resources Inc., reported on corrosion and insulation in CFBs. Corrosion is a chemical reaction that occurs deep down at the pore level of the metal. This corrosion is often hidden by the insulation. Coatings are an anti-corrosion approach that attempts to keep the metal surface protected from the corrosive materials. However, there is no way to prevent moisture from contacting the metal. The coating adheres to the surface to cover the metal. However, they don ’ t typically penetrate to the pores. Penetrating moisture cured polyurethanes can penetrate into the pores and are resistant to moisture, acids, and salts. They are also pressure resistant, which is important as the moisture that converts to steam on heating causes a high local pressure. A full cure surface tensile strength of 10,000 - 12,000 psi can be achieved without the need for white metal blasting.

Conventional insulation that uses fiberglass allows humidity to penetrate to the base of the metal. This moisture sets up the situation that can promote corrosion under insulation. Ceramic thermal barrier systems. The material can be applied while the system is in operation. It can be used on applications up to 900 F. It can be applied on hard to cover areas. The insulation parameters are superior. Heat loss is minimized. The system eliminates cold sinks and vapor drive by preventing water penetration. These systems are routinely applied in Japan. The system also “reflects” heat from the outside.

**John Kang**, Jacksonville Electric Authority, reported on their optimization experience with one of the largest CFB units in the US. About 5 years ago, the two 300 Mw CFBs were experiencing high forced outage rates (20 - 25%). The units were installed in 2002.

The original design was for 297 Mw, but the system could not get above 280 Mw. The CFB has 3 cyclones with 3 Intrex heat exchangers. There were 4 stripper coolers. The primary fuel is petcoke. In the last year, the forced outage rate was reduced to less than 5% and the steady state output has been increased to 312 Mw.
The original loop seal had some heat transfer surface has been removed. The Intrex SH tubing has had to be replaced. The unit has a spray dryer absorber (SDA) in order to get 98% SO2 removal. The spray nozzles are cleaned every day. Hydrated flyash is used as the sorbent for the SDA. The fuel domes cover the fuel piles. The limestone was originally outside. However, the plant went to sized limestone and a covered facility. This approach solved a lot of handling problems with the additive system. Cyclone pluggage has been a serious issue. Some plugs took up to a month to clean out. Stripper coolers and Intrex heat exchangers also experienced plugging. The unit was still operating in manual mode until 2008.

Extensive fluidization studies were carried out. Modifications were made to the fluidization system and surface modifications were made. The furnace was running hot as a result. An optimization team was formed in 2007. Six sigma concepts were employed to evaluate improvements. Prior improvements were based on making changes to improve fluidization, to correct steam temperature problems, and to correct problems caused by prior changes. The approach required operating data to justify any changes that were being proposed. Weak areas included bed level control, stripper cooler performance, high sulfur pet coke, and cyclones. Challenges included accuracy of flow measurements, availability of measurements, accuracy of valve and damper positions, poor DCS control, lack of standard operating procedures, and “tribal operating knowledge” about operating equipment.

The team changed the focus to looking at data when the unit was running well. The high cyclone inlet temperature was correlated to primary air flow. Units 1 and 2 do not necessarily operate the same. The plugging of the cyclones appeared to be caused by too high a mass level in the furnace. Operating with less material in the system allowed for better cyclone control. The potassium content of the ash correlated with ash problems. Maintaining steam temperature was also a problem. Correlations were developed to determine the variables that influenced the steam temperature performance. Fuel and limestone sizing was brought under control. Surface analysis was done once the unit was stabilized. Additional surface is being proposed. The bed temperature has been reduced from 1800 to 1720 F. The variation in main steam temperature was greatly reduced. With the improvements in the SDA, the limestone utilization improved. Ammonia consumption has also been reduced.

The major lessons learned is that fluidization is key, with ash quality being the important parameter. Cyclone plugs can be avoided by controlling the amount of solids in the system. Sticky ash does not like to flow. Reducing the potassium and sodium helps to reduce the sticky ash potential. Adding kaolinite helped to minimize the formation of low melting compounds. Petcoke ash has more alkalis than desired so that kaolin injection is used to tie up the alkalis. In the future, gas co-firing, and biomass firing will be tested. Load cycling will also be tested.

**Matt Dooley**, Sigma Energy (ALSTOM Power, Inc.) reported on the energy assessment of a 117 Mw CFB unit at Colver using the heat rate/heat loss method. Colver had noticed an increase in heat rate of 500 BTU/Kwhr and wanted to determine either the reality or the cause of the problem. The unit was operating reasonably well, but there was a degradation of heat rate compared to a reference point. The unit was originally designed for a lower load with a poorer quality fuel. A reference point had to be estimated for the unit. The design heat rate was 10,447 BTU/Kwhr and the as found heat rate was 10,982 BTU/Kwhr.

The turbine had some losses attributable to the HP section. Cycle isolation had to do with valves and piping. Auxiliary steam was high during the test due to the fact that the test was done in the winter when additional steam was needed for low temperature control. Increasing excess air was proposed to reduce the bed temperature. Cycle isolation losses (leaks, etc.) always contribute to reduced efficiency. The tubular air heater is subject to corrosion in the cold corner. High leakage resulted from corrosion. Limestone fineness was another consideration. The plant was experiencing a high Ca/S ratio of about 4. This resulted in additional calcination loss, additional heat loss from the bed drains and the fly ash, and additional pressure drop.

Testing of the limestone showed somewhat better reactivity at a higher bed temperature. Particle size distribution is important for good FBC operation. A “steeper” cut is desired for good CFB operation. A lot of fines causes the fine material to leave as fly ash with little time for reaction and carries heat out the system. The air heater leakage limited the fan capacity to provide excess air. The lower air flow led to higher bed temperatures. Improving the particle size, slightly lower bed temperature, and reduce Ca/S improved the boiler efficiency from 83.21% to 84.97%. This improvement was nearly 180 BTU/Kwhr. The air heater appeared to be performing as designed, but there did appear to be other air leaks that were causing issues. The HP turbine efficiency appeared to be low by nearly 5 points (72.6% vs 77.7%). The IP and LP efficiencies were pretty much at the design levels. The FW heaters were analyzed. The flow appeared to be 5.8% too high. There seemed to be a likely tube leak somewhere. Instrument accuracy is important. The conclusions are only as good as the data, which is strongly dependent on the accuracy of the instruments.

IX. CFB Ash Management and Utilization - Robin Ridgway, Purdue University

In addition to **Robin Ridgway**, **Sharon Hill** of the PA Dept. of EPA and **Mike Riley** of CA Byproducts joined the panel. **Robin Ridgway** noted that ash utilization goes back to the first large scale use of coal ash in 1949 in the construction of the Hungry Horse Dam in Montana. RCRA was enacted in 1976. The Bevill Amendments were enacted in 1980. Several times the EPA issued a report to Congress that coal ash does not exhibit hazardous characteristics.

In 2006, the National Academy of Sciences issued a report on managing coal combustion residues in mines. In June 2010, EPA issued a proposed rule. Comments were due in November 2010. The proposed rule was targeted at electric utilities. The preamble suggests that the rule is not applicable to beneficial use, mine fill, or industrial facilities. However, the regulatory precedent could easily apply to industrials and the state programs are not likely to differentiate when it comes to implementation. The subtitle C option is federally enforceable. The subtitle D option is not federally enforceable, though it could be enforced if the activity were not compliant with subtitle D. There is more flexibility in subtitle D. The "C" determination carries with it the stigma of being associated with a hazardous waste," which will likely preclude beneficial use.

The regulation starts from the point of generation (inside the boiler?). The land disposal requirements essentially eliminate the potential for using a surface pond impoundment. Liners and ground water monitoring will be required. Even under the "D" designation, the source would have to maintain a web site that is available to the public showing that the site is in compliance with the regulations.

There are a number of options that were also proposed. EPA requested public comments on all of these proposals. EPA received over 450,000 comments. A number of Congressional members have written letters to EPA requesting a "D" determination. Representative McKinley has proposed a bill to that effect. EPA has stated that they would delay issuance of a final rule until after the 2012 elections. The OSM has announced plans to move ahead with mine fill regulations.

**Sharon Hill** reported on the Pennsylvania program for beneficial use. The program started with regulation by guidance. Since regulations from EPA take a long time, the state implemented a lot of the recommendations that were proposed in the NAS report. The environmental groups were brought into the process to give them a chance to provide input. As a result, the state regulations are well ahead of the national level. However, current media themes still persist. Pennsylvania has a lot of data. The data can be "cherry picked" to attempt to demonstrate a point. However, the data is useful to defend the program.

The department's role is regulatory rather than advocacy. Industry still must advocate for beneficial use. The program has separate sections for each use. Certification is centralized with the Bureau of Mine Reclamation. Loopholes and exemptions were closed. Questionable ash is not needed for reclamation. The definition of coal ash was modified slightly to exclude ash that was mixed with scrubber sludge. The ash has to be maintained at least 8 ft over ground water. Waivers on chlorides and sodium were eliminated. A permit fee was assessed (department budget was reduced). There is a requirement to report volumes.

The generators and the mine sites have to report. Sometimes the sums don't match up. All parameters must be sampled. This provides data to support the various claims of safety and compliance. Water monitoring parameters now match up to the ash monitoring standards. There are standards for monitoring wells. Stricter site evaluation processes are in place. The hydraulic conductivity test was implemented, but is expensive. If there is a better test, the agency wants to know about it. Fact sheets have been completed (one for the generator and one for the mine site). The form updates reflecting the new certification limits and parameters are in process and should be ready soon. Electronic submission is preferred. Revised technical guidance documents will be updated. Generators in PA are responsible to provide updates to the agency, including e-mail addresses. The CA number is important because it is the certification number for approved benefices' use and generation of coal ash. Burning other materials can jeopardize the use of ash at mine sites. The new regs are more stringent, but the program is defensible and the state has 20 years of data to show that no degradation has occurred.

**Mike Riley**, CA Byproducts, reported on the coal ash utilization at the Grantown plant. The National Ash Association was founded in 1968 and is now the American Coal Ash Association. While the main constituents of coal are silica, alumina, and iron oxide, many other elements can be identified. The 4 main classifications are Class F, Class C, fluid bed, and flue gas desulfurization. The major difference in the Class C is the higher level of calcium in the ash. Moisture content is less than 1%. The use of flyash was 29 million tons out of 71 million tons in 2005. In 2006, 125 million tons was produced (including flyash), of which 43% was recycled or reused. Utilization comes from fly ash (64%), bottom ash, slag, and FGD sludge (13%). The uses include concrete production, embankments, and road salt/sand. Soil stabilization, lightweight aggregate, flowable fill, and asphalt concrete are additional beneficial uses. Mine reclamation provides significant use in Pennsylvania and West Virginia. A new application is the use of CFB ash to stabilize drilling pads in the Marcellus Shale drilling fields.

X. Backend Technologies - Gary Merritt, Inter-power/AhlCon Partners, L.P., Moderator

**David South**, Amerex, reported on backend technologies to meet future regulations. Amerex specializes in $SO_2$, $SO_3$, PM, mercury, HCl, and HAP comtrol. There is also an aftermarket parts and services group. Installation experience includes units from 25,000 pounds/hr up to 1 million pounds/hr. Sodium bicarbonate or trona injection forms the base of the capture technology. A pulse jet bag filter is used to build up a filter cake for acid gas capture. The PM guarantee for total filterable emissions is 0.0011 lb/MMBTU. The filterable $PM_{2.5}$ limit was 0.0029 grains/acf. The HCl limit was 0.0022 lb/MMBTU. The $H_2SO_4$ limit was 0.0035 lb/MMBTU. Activated carbon is used for mercury capture. The mercury limit was 3.5 lb/trillion BTU. The dioxin/furan rate was 0.02 nanogram/dry scm at 7% $O_2$. The estimated delivery time is 30 weeks from order. Warranty items include pressure drop, bag life, and noise. The combination of the sorbent injection for acid gas control, activated carbon injection for mercury and D/F control, and the pulse jet bag filter provides the opportunity to comply with Boiler MACT requirements for 4 of the 5 surrogates (PM, HCl, Hg, and D/F). The CO requirement is primarily a combustion control problem.

**Mike Cornell**, Siemens Environmental Systems (former Wheelabrator Environmental), reported on air pollution control design considerations to meet MACT standards on fluid bed boilers. Fabric filters are still the main control technology to meet the standards. However, the conditioning of the flue gas prior to the bag house and size of the baghouse are now more complex. Pulse jet fabric filters are typically specified. Considerations include minimizing the pulse rate, low velocities, gas distribution, and filter material. A perforated baffle plate is used to direct the gas to the bags. Gas flow modeling has been used to develop a system with balanced flow distribution, low compartment velocities, and low pressure drop. A pulse tube is used to direct the pulse jet into the bags for cleaning. The hole size is varied in order to get a more uniform pulse across a bag row. Up to 23 bags can be cleaned simultaneously. Intermediate pulse technology (30 - 35 psig) is used to improve bag life. Longer bags can used, which reduces the number of bags and associated hardware. Emission rates as low as 0.0003 lb/MMBTU were measured. Hydrated lime can be used for both SO2 and HCl control. Powdered Actwater Carbon (PAC) or Brominated - Powdered Activated Carbon (B-PAC) can be added for mercury control. A variety of dry” scrubber or dry” sorbent injection systems can be deployed. SO3 competes with mercury for sites on the activated carbon. For most fluid bed applications, the SO3 levels tend to be relatively low. For fuels with relatively low chloride in the fuel, B-PAC is recommended for mercury and dioxin/furan control.

**Jeff Arroyo**, SEGA, reported on biomass co-firing and emissions impacts. There have been a number of biomass co-firing projects that have gone ahead in the past few years. These applications are good for smaller plant sizes.

**Heidi Davidson**, Solvay Chemicals, reported on HCl and SO2 mitigation with dry sodium sorbents. Trona and sodium bicarbonate are the primary dry sorbents that are used for acid gas control. Typically dry sorbent is delivered by truck to a storage silo. Injection is typically after the economizer. Injection temperature usually needs to be above 275 F. The system is fairly simple to design and operate. The reagents and by-products are relatively safe to handle and non-corrosive. There is no liquid effluent.

Trona is a naturally occurring mineral called sodium sesquicarbonate. Sodium bicarbonate is baking soda. Solvay mines trona and manufactures sodium bicarbonate in upstate NY. Either material calcines to sodium carbonate when injected. The calcination process makes the sodium carbonate more reactive as compared to the mined mineral. The sodium carbonate reacts with acid gases (SO2, SO3, HCl, HF, etc.) to form sodium salts. The calcination occurs at temperatures above 275 F. The calcined material is highly porous.

In one application at a coal fired boiler 390,000 lb/hr, the SO2 level was up to 350 ppm and the HCl was up to 40 ppm. The injection temperature was 330 - 390 F. Sodium bicarbonate was injected. Even with low levels of SO2 capture (20%), 60 - 80% of the HCl was captured. At higher SO2 capture rates, over 90% of the HCl was captured. At a 100 Mw unit burning low sulfur coal, over 98% HCl removal and 80% HF removal were achieved. At a waste incinerator in Europe, over 99% HCl removal and 91 - 95% SO2 removal were obtained simultaneously with the use of baghouse. The sorbent is normally milled to obtain a particle size in the range of 10 - 50 microns.

A gas residence time of about 1 sec is desirable. A baghouse provides for a somewhat longer residence time. All of acid gases react with the sorbent and need to be considered in estimating the amount of sorbent that needs to be injected. Thus, for high sulfur coals with no prior sulfur control, the cost of the sorbent becomes quite high. The injection of trona or bicarbonate helps the PAC or B-PAC systems as it reduces the level of SO3 in the gas, which competes with mercury for sites on the activated carbon. Stoichiometric ratios range from 1.0-1.5.

**Mike Schantz**, Lhoist North America, reported on dry sorbent injection using calcium hydroxide. The chemistry of calcium hydroxide is similar to the sodium. Dry sorbent injection for HCl control has been standard in Europe for MSW applications. The levels of chloride are higher in these plants than in a typical coal fired boiler. Lhoist is the largest calcium mineral supplier in the world. Calcium injection systems started with the DOE LIMB (limestone injection multi-burner) program. At that time, the SO2 removal level of 50 - 60% could not compete with wet scrubbers. In 2004, TVA had an opacity problem due to SO3 levels in the flue gas. A dry calcium injection system captured the SO3 and resolved the problem.

There has not been a lot of experience on the use of hydrated lime for HCl control in coal fired power plants. Important factors include flue gas properties, reagent properties, and injection system configuration. Competing acid gases impact the capture of HCl. SO3 is the strongest acid, followed by HCl, SO2, and HF. Since the LIMB program, the hydrated lime properties have been improved by increasing the active surface area of the particles. Finer particles with much higher surface area and chemical activation can allow capture with much less material.(on an HCl basis). Global stoichiometric ratios of 1.0 - 1.8 were tested for “ standard ” hydrated lime and activated hydrated lime. With an optimized material and a baghouse and a reasonable chloride level, it should be possible to meet the HCl requirement of the Boiler MACT. At low injection temperatures (300 F), SO2 capture is low, but HCl and SO3 capture is fairly high. At higher temperatures SO2 capture increases significantly and HCl capture falls off. Hydrated lime can be injected ahead of a wet scrubber to capture SO3, which tends to go through a wet scrubber. The resulting calcium sulfate dissolves in the scrubber water.

High levels of injection in front of an ESP risks overloading the ESP. Injection ahead of an SCR has been considered to reduce any arsenic, which is a catalyst poison. It might also be possible to reduce the selenium as well. The reduction of SO3 helps the activated carbon system in collecting mercury. The reduced SO3 also reduces the PM2.5. Another potential application is to remove the HCl and SO3 ahead of the particulate removal system as well as the wet FGD system. This keeps chlorides out of the wet FGD, which reduces the waste water treatment requirements for the scrubber. When all of the ash, additive, and activated carbon are simultaneously collected in a particulate system, the resulting ash needs to be tested for leachability or utilization to make sure that the material can be handled appropriately.

XI. Overview of the Evergreen Community Power Plant - **Peter Kline**, Evergreen Community Power Plant

The plant is currently in operation. The company is affiliated with INDEVCO which is an international group that produces paper, plastic, and corrugated packaging. In the US, United Corrstack runs the paper plant and Evergreen runs the 300,000 pounds per hour cogeneration plant. The steam and most of the electricity is sold to the plant. Any excess is sold to the grid. Prior to the installation of the power plant, the paper plant had a natural gas fired boiler with purchased power from the grid. In 2006, the owners committed to the power project. The CFB was provided by Austrian Energy (now Andritz Energy and Environment). The unit has a multiclone, trona injection, SCR, and hot side ESP. A Siemens 30 Mw turbine provides the electric generation. The fuel is sorted construction & demolition biomass. The plant is located in the city of Reading, PA. The entire plant is less than 6 acres. Fuel is delivered by truck. Ash is removed from the site by truck.

The CFB uses flue gas recirculation for bed temperature control and a single cyclone. The entire backpass is convective surface including the walls. The grid floor is open with just bars making up the grid. There are 4 air hoppers under the grids to supply the air. Conveyors are enclosed to avoid dust issues with the city. The fuel storage silo is a 120 ft high, 80 ft diameter tank. A screw augur sweeps the bottom of the silo to drive fuel to the center off take of the silo. There are 2 x 100% feed systems with double screw augers. There are two feed points at the walls of the unit.

The air permit was received in June of 2007. The first fire was June 2009 with turbine synchronization in August 2009. A broken bolt on the turbine extraction grid valve caused a shutdown in Sept. 2009. In November 2009, the silo experienced a wall buckle caused by a rat hole. It took some time to empty the silo. The metering bins then started to plug. Bearing failures and wear on the augurs caused some additional problems. Soot blower erosion caused some tube leaks. A vortex finder failure was caused by a bed weld. Back pass fouling in the second superheater continues to be a problem.

> Currently, on line water washes are being used to help reduce the pressure drop. Challenges include multiclone performance, SCR catalyst fouling, trona feed system, ash handling limitations, and fuel receiving limitations. While boiler availability has been maintained, the system has been restricted to about 70% load due to other problems. In the April outage, a number of areas were addressed. Capacity after the outage has been generally above 90%.

XII. Plant Tour - **Peter Kline**, Evergreen Community Power Plant

Additional items observed on the tour included the following:

-The location of the trona injection was varied and now is at the inlet to the multi-clone to provide additional residence time.

- The steam turbine has a 100% bypass and a full flow condenser from 1200 psi steam

- The cyclone is brick lined.

- An additional shredder and recycle system was added to the main fuel feed system as considerable light material with high BTU content was "floating" over the scalping screen to the disposal dumpster. By sending this material to shredder and then back to the screen, the amount of material to be land filled was reduced by 80%.