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I. Fundamentals of Biomass Combustion in Bubbling Beds - Phil McKenzie, B&W

Interest in biomass combustion is currently very high. Biomass is a general term for a wide variety of combustable materials derived from plants. These range from relatively high grade wood products to bark to bagasse to rice hulls to grasses and leavings. Woody biomass consists of chips that can be conveyed and have a reasonable heating value. Even so, the fuel is variable. Variations include moisture content, ash constituents (and content), aging, glue, particle size, and associated waste materials (nails, packing, etc.). Wood pile management includes moving and blending the various deliveries to achieve a somewhat more uniform feed to the boiler. B&W is offering a 50 Mw. top supported, high pressure (2000 psi), bubbling bed for biomass applications.

Starting with a slumped bed, air is gradually added until the particles in the bed just lift off the grate. At this point, the pressure drop through the bed is just equal to the weight of the bed. As the particles lift, the properties become like a fluid. The particles rearrange themselves so that the pressure drop goes down slightly. As the air flow is increased, the additional air enters the bed in the form of bubbles which rise up through the bed, moving the solids in front (above) them. These bubbles give rise to the name, bubbling fluid bed. As the bubbles reach the surface, they break apart and splash the particles into the freeboard. The particles fall back to the bed and are mixed in with the material in the bed. If more air is added, a velocity is reached where the smaller bed particles are carried out of the bed. Until the velocity reaches the terminal velocity of the particle, the particle velocity is less than the gas velocity. If these particles are captured and recirculated, a circulating fluid bed is created. Once, the terminal velocity is reached, the particles are carried along at the gas velocity and a transport regime is achieved.

The B&W design uses a bed depth of about 36 - 40 inches. For fuels with insufficient heating value can utilized support fuels to provide the required energy to maintain bed temperature. For fuels with a relatively high heating value, in bed tubing can be utilized for additional heat transfer. The bed is generally run with a slightly substoichiometric theoretical air level with the rest of the air being introduced over the bed. The variations in fuel moisture are accomodated by changing the bed stoichiometry to match the heat liberation that is needed. For wet fuels, more air goes to the bed. For dry fuels, more air goes to the freeboard. A three level system can be used to minimize NOx formation.

BFBs tend to be lower in capital cost than CFBs, particularly in smaller sizes. The auxiliary power load is somewhat less than the CFB (no recirculation). B&W will offer biomass bubbling beds up to 100 Mw. As soon as coal is involved, the emphasis shifts towards CFBs. The CO levels are comparable. Turndown capability is in the range of 4 to

1 or 5 to 1. For erosive fuels, lower velocities are deployed to minimize the erosion potential. The fluidizing pressure tends to be about 55 inches. Although emissions limits vary from state to state, typical control requirements are for chlorides, NOx, and particulates. A baghouse is fairly common for particulates. Additives are used for chlorides. Air staging and SNCR can be used for NOx. New York State is requiring SCR. If the unit gets classified as an incinerator, there are more emissions to consider as well as lower levels to be achieved. In particular, there are time and temperature requirements for incinerator units.

II. Equipment Suppliers Forum - Facilitator - Charlie Wagner, B&A Engineers

Bill Campbell noted that recent permit requirements have asked for emission values at intermediate load (50 - 70%) range especially if the unit is not likely to comply with the full load condition. Start up and shut down is still in play (requires a start up, shut down, and malfunction plan). Averaging times, SCR/SNCR, and over control at full load are some strategies that can be followed. No equipment values were presented. The environmental groups have been emboldened as a result of the new administration. A 10 Mw unit at the University of Michigan was targeted and a number of precedents were established. Something called " fuel BACT " was put forth, which asks for the fuels that the boiler could burn and establishing which ones are cleaner.

Bob Bibb noted that we used to have New Source Performance Standards that provided a number to meet. Now that has long since been supplanted by state by state requirements and top down BACT. As far as, " How clean is enough? " , Bill Campbell noted that it is pretty much as good as you can do. In order to get a permit, good, solid technical data is required to back up the position on emissions limits. Mike Alliston pointed out that some requests for emissions levels at 40% load. It becomes important to note that lb/MMBTU at low load has a lower denominator so that the emissions level will likely be higher, although the lb/hr of emissions is much less. There is also uncertainty over the level depending upon the type of operation. Owners (and some suppliers) do not want to have their operating data made public.

Bill Pollock of Nalco-Mobotec noted that mercury monitoring has improved. However, variation in fuel can be in the range of a factor of 10. Without matching fuel analysis and monitoring measurement, it is difficult to determine what works and what doesn ' t. SO3 is a problem for activated carbon and mercury control. The SO3 competes with mercury for the sites on activated carbon. Reducing the SO3 would be a requirement before activated carbon can be successful. This does help with the condensable particulates, but adds to the cost.

Market activity has shifted towards units that either co-fire or utilize biomass. There is a push to biomass due to CO2 considerations. These will put pressure on prices for biomass. During the 1980s, agricultural projects in California were proposed based on $15/ton for agricultural waste (almond pits, leavings, etc.). In a relatively short time, these wastes rose in price to $70/ton. This made new projects uncompetitive. Coal for small units is very difficult as the permitting process requires staying power. Only the large utilities can justify taking the time or making the effort to permit a coal fired unit.

The Markets Division of EPA has to wait for Congress to pass legislation in order for EPA to set up a " cap and trade " system for CO_2. The details of such a system are specified in the legislation. Topics such as banking, borrowing, bonus allowances, and other features all must be delineated in the legislation. The cap and trade system for SO_2 was very successful. The nation reached the cap level last year, several years ahead of schedule. SO_2 allowances are currently selling for $70/ton. Original estimates ranged as high as $5,000/ton.

Gas prices have declined with the recession. Unconventional gas deposits have been discovered and can be developed at reasonable prices. For smaller units, the problems associated with permitting coal plants and the uncertainty associated with CO_2 and flyash considerations make gas look very attractive. Of course gas prices have been volatile. Whether the price level would return to the $13/MMBTU range is speculative at best. The likelihood is that gas prices will remain moderate in the short run.

Iqbal Abudullaly noted that tests at Gilberton on SCR for a CFB have been reasonably successful. There had been serious concern about poisoning the catalyst. However, for CFB applications, the SNCR process is much cheaper.

With respect to co-firing biomass in existing units, assuming reasonable fuel constituents, a fuel feed system needs to be considered. The level of 10% is still generally feasible. Higher levels can be achieved if the fuel ash is low in alkalies.

Bob Bibb noted that there has been some interest in waste to energy projects. Permitting problems are one issue. Cost issues are site specific. Classification as an incinerator, as opposed to a boiler, is another concern. The combustion of nuisance fuels will not necessarily get a break, but the permit level will typically be what the back end control equipment can do.

III. Owners and Equipment Suppliers Forum Discussions - Facilitator - Bob Bibb, B&A Engineers

The Owners Panel consisted of Glen Costa from Perdue Farms, Robin Ridgway from Purdue University, and John Thalhauser from Archer Daniels Midland. The Suppliers Panel consisted of Don Mylchreest from Alstom, Louis Nichols from EPA, and Tom Sheppard from Lutz, Daily, and Brain. Robin noted that the owners talked about fuel flexibility (getting the fuel in can be challenge), engineering controls/technology, environmental requirements, and training issues. Fuel flexibility is becoming more of a requirement as states move towards renewable portfolio standards and fuel prices continue to be an issue. In the case of the University, it will be nearly impossible to tear down the existing plants and start over. Thus, the possibility to co-fire some kind of alternative fuels becomes an issue. ADM is looking at corn stover. With higher yields on corn, less stover is needed to go back into the fields. With an excess of stover, the opportunity to utilize this material would be ideal. None the less, just to bring in feed equipment cost several hundred thousand dollars. The owners have noticed a lot of new engineers that lack experience coming into the industry. Don Mylchreest noted that the suppliers discussed the increasing number of requests for biomass or other alternative fuels. The supply and price of these fuels can fluctuate. In California, the prices for agricultural wastes started at $15/ton and rose to $70/ton. This price level made a number of plants uneconomical. The price has since declined. Similar issues arose for tires and other waste fuels. Louis noted that the EPA Markets Division has to wait for Congress to provide legislation for a cap and trade program for CO_2. The existing cap and trade program on SO_2 was very successful. Tom Sheppard pointed out that permitting is getting more difficult. It is also a moving target. Cherry picking by the permit writers is a problem. The environmental groups have been emboldened by the election and are pushing on every limit in every way. Emission levels at part load are being requested. Robin noted that operator training is another issue requiring attention. The owners surveyed themselves to see how many were working on new projects. Of the 27 in the meeting, only 4 were working on new projects. Another question was about working with utilities to meet some of the renewable standards. In California, utilities are scrambling to meet these standards. This has caused a change in the position on PPAs in California. Of course, these costs are expected to be “ passed through ” , which will translate into a price rise in utility rates. Fuel supply reliability is a key issue. Multiple users have been evaluating the same fuel source. Competition for the biomass (forest products, ethanol, fuel, etc.) will impact the price and availability.

IV. 2008 FBC Owner Survey Results - Jack Fuller, West Virginia University

Each year CIBO does a survey of owners of CFB units. A separate project on a baseline of alternative fuel usage is being developed with CIBO and DOE. This year 21 plants responded with 40 boilers in the survey. Of these, 15 plants were larger than 40 Mw. Of the 40 boilers, 37 were CFBs. The fuel sources included 11 coal, 5 gob, 2 petcoke, and 2 biomass units. There were 6 sources that had secondary fuel sources which included petcoke, tires, and biomass. The larger units tended to have better heat rates. Overall availability remains at slightly over 90%. Interestingly, the gob units are averaging close to 95%. The newer plants (post 1990) exhibited slightly better availability (92%) compared to older plants (88%). Of the total unavailability, about 35 - 40% is due to forced outages. The forced outage rate was not markedly different with age. The forced outage rate for the auxiliary equipment was significantly greater than the rate for the boilers themselves. Older units had fewer boiler related outage hours than newer units. Of the boiler related forced outages, tube leaks were by far the greatest contributor. The next area of steam turbines/generators was considerably lower in forced outage rate. There were a total of 40 different outage causes requested on the survey. Most of these items were small enough that they were not included in the slides.

V. Manufacturer’ s Panel - Moderator - Bob Bibb, B&A Engineers

The panel members included Scott Darling, Alstom; Phil McKenzie, B&W; Tom Steitz, FW; and Michael Alliston, Metso. Phil McKenzie noted that biomass has been the focus for B&W. Clean energy technology efforts include ultra super critical boilers, environmental controls, carbon capture and storage (oxygen firing), solar boilers, and nuclear. A solar boiler was shipped for a demonstration this year. This was a power tower application. Forest biomass is concentrated in the Southeast, Northeast, and Northwest. For woody biomass, about 7 - 8 times the volume of coal is needed to get the same energy output. This is due to the lower heating value of the biomass and the lower bulk density. A 100 Mw unit with 50% moisture wood requires 163 ton/hr of wood or 195 trucks per day. This presents a logistics problem. Trucks typically do not deliver at night or on Sundays. Thus, in the middle of winter, this average 200 trucks needs to get into the plant in something like 6 hours. The flue gas mass flow is on the order of 50% higher for biomass due to the moisture content. This means larger boilers, larger duct work, larger air heaters, and different surface arrangements. Scott Darling pointed out that Alstom is involved in nearly all aspects of the power plant. Alstom tends to concentrate on the larger projects, especially the 200 - 400 Mw CFBs. Alstom has experience with all types of fuel, including biomass and waste coals. CFBs offer considerable flexibility in co-firing. At the Gilbert plant a wide range of coals were planned, ranging from very poor coal to high quality coal. Tire derived fuel was tested at up to 15% heat input. This fuel was mixed with the main coal fuel. Wood chips have been tested as well. Switch grass testing is planned for 2009. There are alkalies in switch grass which will limit the amount of this material that can be co-fired. In California, petcoke is being co-fired with the design wood and agricultural waste. The law enforcement agencies have used the plant to burn confiscated substances from time to time. Alstom has the most experience in supercritical boilers and has applied this experience to CFB units. For CFBs the relatively constant heat flux in the furnace allows for a once through design as the peak heat flux around the burner zone of a PC unit is eliminated. CO2 mitigation strategies include back end scrubbing, biomass firing, and oxygen firing. Amine scrubbing has been installed on 2 Alstom units for food grade CO2 (Shady Point and Warrior Run). A slip stream from the flue gas is scrubbed to recover the CO2 as a cogeneration application. The CO2 is used for dry ice at one location and beverage carbonation at the other. Oxy firing has some unique aspects for CFB applications in that the solids recirculation can utilized for temperature control instead of or in combination with gas recirculation. Alstom has a number of demonstration projects for CO2 capture including chilled ammonia, advanced amines, and oxygen firing. Tom Steitz noted that FW has a number of technologies to apply to biomass firing including CFBs, bubbling beds and grate technologies. A wide variety of fuels can be burned in these units. The fuels with multiple challenges high variability such as municipal solid waste (MSW) tend to require grate technology rather than pulverized coal or fluid bed technologies. Bubbling bed units have been offered since 1970 have up to 100% biomass capability. A stepped grid can be used with multiple discharge points has been developed to handle more difficult fuels. In Europe, there are 9 of these type grids in operation (Finland). The stepped grid slopes downward towards the discharge points in order to keep the heavier materials moving towards the discharge. In the last 5 - 7 years, a number of bubbling beds have been installed in Europe for biomass ranging from 10 - 60 Mw. The stepped grid design has been adapted to the CFB with 18 units in operation. FW has CFB designs up to 800 Mw. Features include the INTREX heat exchanger and an idle back pass for difficult fuels. Options for biomass include reduced bed temperature, reduced steam temperatures, additives for the bed, and a sand flush to minimize ash agglomeration problems. A number of biomass CFBs have been installed in Europe in sizes up to 125 Mw. A " typical " size would be about 45 Mw. The largest CFB firing biomass is in Canada firing hogged wood and other wood wastes at a paper mill. A plant design for a 2 x 330 Mw CFB system in Virginia has been modified to allow for the co-firing of up to 20% biomass (forest residue) with waste coal. The wood fuel is about 45% moisture at 5000 BTU/lb. Mike Alliston of Mesto pointed out that the origins of the companies include Gotaverken, Keeler Dorr Oliver, Tampella, and Kvaerner. The fluid bed process is an amalgamation of combustion technology, boiler technology, and fluidized bed technology. One of the issues for biomass is getting enough fuel for the unit. A 260 Mw unit requires 30,000 cubic feet per hour of biomass. Co-firing with coal provides additional heat and provides backup for those times when biomass is not available. A " hydro beam " bottom is used to remove " rocks " from the bed material. These water cooled beams can allow heavy particles to fall through the grate and be cooled. Agglomeration is typically caused by alkalies in the fuel. Co-firing with coal tends to dilute the alkali materials from the biomass with the larger quantity of coal ash. A similar situation exists for corrosion potential. If chloride levels are too high, the high temperature superheat surface can be located in the fluid bed heat exchangers.

VI. Alternative Fuels - David South, Technology & Market Solutions, LLC

Energy challenges include the problem of price forecasting going forward. Although hedging strategies are available, natural variability of the weather, supply disruptions, and political instability make price forecasting difficult at best. Co-firing with biomass can provide a hedge on fuel prices going forward. The majority of states have renewable portfolio standards which creates renewable energy credits. Wind and solar can generate some of these credits, but are intermittent by nature. Capacity factors are on the order of 15 - 25%. The estimated costs for new transmission lines for wind farms is up to $100 billion. Biomass can be a baseload technology. However, the plants will probably be smaller to avoid the problems associated with the collection, transportation, and delivery of the biomass. There are also greenhouse gas initiatives in a majority of the states. RGGI is already operative in the Northeast. The Western Climate Initiative will start up in January. There is already a carbon market even in states without GHG regulations. There are a lot of potential revenue streams to be considered for any project. These include conventional emissions allowances, offsets, nutrient credits, production tax credits, investment tax credits, and renewable energy credits. In addition, the " stimulus bill " has provision for projects that are clean, green, and " shovel ready " . Loan guarantees and renewable energy provisions can be used for these projects. In some cases, the tax credit can be converted into a grant that can be used as equity for the project. Thus, alternative fuels can facilitate the continued use of fossil fuel technologies through co-firing. Smaller projects can qualify as distributed generation which has transmission and distribution benefits.

VII. Biomass Fuel - Tom Sarkus, National Energy Technology Laboratory

Biomass, blends, and co-firing are the keys to success with these fuels. The reasons for blending include fuel supply, economics, environmental pressures, or regulatory issues. Common blends include coal blends, coal and coke, coal and tire chips, PRB and lignite, and coals and biomass. Fuels are unique and blending two fuels creates another unique fuel. Taking an eastern bituminous coal with 12,000 BTU/lb and mixing in 20% by heat input of woody biomass creates a fuel with 9,000 BTU/lb. Fuel handling is not glamorous but very important. Biomass needs to be kept separate from coal. Biomass that is fibrous is not suitable for conventional coal handling equipment. Ash content and properties include moisture levels, sulfur, chlorine, alkalies, and iron contents. Flame profiles tend to be different for burners using blended fuels. Blended fuels have different efficiencies. Deposition and corrosion concerns need to be addressed. At 20% biomass, the gas flow increases by 28%. Blending is becoming more common. Blends will involve more low rank coals, waste fuels, and green fuels. Each blending application is unique. Blending issues must be addressed recognizing subtleties of the fuels and interactions between components. Blends do not behave as the weighted average of the components. Biomass or other co-firing materials should be limited to 10% by weight to minimize operating problems. This will add 7 - 10% in capital cost for the new feed systems.

VIII. Panel Discussion on Alternative Fuels - Moderator - Robin Ridgway, Purdue University

The panel consisted of Harvie Beavers, Colmac Clarion; Gary Mell, Michigan State; Carmine Gagliardi, Air Products; Peter Kline, Evergreen; and Daniel Traynor, Northampton Generating Company. Each of the panelist has at least one plant that is burning (or will burn) some kind of alternative fuel (including TDF, petcoke, paper mill sludge, and biomass). The Stockton plant in California has run through a fairly wide range of " opportunity " fuels originally driven by fuel cost issues. Petcoke, TDF, nut shells, and orchard prunings have been utilized. Chlorides and alkalies are monitored closely to avoid plume issues from the chlorides (due to SNCR ammonia slip) and agglomeration issues. The Evergreen plant in Reading, PA was driven by high natural gas prices. The area is running out of landfill space. They have teamed with someone that can identify potential fuel sources and process the fuel. The 30 Mw unit processes 800 tons/day of biomass type fuel. The Northampton facility is known for utilizing alternative fuels and is permitted for a wide variety of fuels. For TDF firing, the State of Pennsylvania took 4 years and additional testing. The fuel cost is about $35/ton. The Colmac plant was originally a waste coal plant. A number of small plants in PA and WV were built to address the waste coal pile problem in the early 80s. In order to qualify, a plant had to be less than 30 Mw and burn waste coal (small power producer). TDF was tested for about a year, but the cost of producing the TDF from tires was too high. A number of waste products were burned. Some of these products only lasted one or two years. A left over product from coke ovens or other gas producers was tested. The fuel potential looked good and the testing showed no adverse effects. The fuel was permitted and the fuel was fired. However, with the demonstration that the fuel could be utilized, the price went up. This reduced the economics to the point where the utilization stopped. Wood is now being considered, primarily for greenhouse gas issues. The 10% level was verified for the existing feed system and boiler operations. One of the fundamental issues is getting the fuel in and getting the residue out. Units that have no supplementary feed system. Mixing the fuel with the coal is a possibility, but density separation, volatile matter explosion limits, and handling considerations give rise to limitations on this approach. Even on relatively small plants, the cost of a second fuel handling system is on the order of $5 - 10 million. Such an expenditure would be prohibitive for doing a short test. Most plants would like to have the fuel processed prior to getting to the plant. Permitting is still and issue as most of the staff is not familiar with the fuel. The process takes 1 - 3 years. Ash disposal presents some issues as the blend will likely produce an ash that has a somewhat different chemical composition. In some cases, the regulatory authorities require testing and chemical analysis to demonstrate that the ash will not result in problems for either the landfill or the mine reclamation operation. In Pennsylvania, a new permit is required because the ash is no longer a pure coal ash that is covered under the Bevill Amendment. In the final analysis, it takes a lot of time and preparation to get to the point of being able to burn an alternative fuel.

IX. Biofuel/Biomass Co-firing: Carbon Implications and Tax Implications - Carl Bozzuto, Alstom

Carl noted that “ cap and trade ” proposals for CO2 amount to a carbon tax. The goal is to put a price on carbon to influence the behavior of consumers. The tax will mostly be borne by customers through higher prices. Economists favor a tax over a cap and trade system as being more efficient. It is easier to administer. It impacts the fuel at the source and it applies to all users. However, besides being a “ dirty word ” , a tax is not always the most effective vehicle. A tax is too easy to pay and forget. There are already taxes on gasoline, for example. The level of tax needed to influence behavior has to be guessed. Finally, a tax does not necessarily result in reduced emissions. A cap and trade system directly influences the overall level of emissions. It allows trading to reach the emissions level at the lowest cost to the economy. Further, trading brings value to reducing emissions below a fixed level that might result from a command and control approach. Trading requires markets. Markets require rules and transparent information. There still needs to be an enforcement mechanism. A $5/bbl tax on oil is equivalent to $0.80/MMBTU. This is the same as $20/ton of bituminous coal or $7/ton of CO2. Biomass now provides about 3.6% of total energy use in the US. In order to provide 10% of the energy use, the consumption of biomass would have to roughly triple. Dried biomass has a heat content of roughly 10 MMBTU/ton. Assuming 100% offset for CO2, the $7/ton would be equivalent to $8.4/ton of wood. For the northern half of the US, relatively fast growing plants can supply about 2 ton of dried biomass/acre. In order to supply 10% of demand, roughly 10 quads are needed. This translates into 5 billion acres. The total arable land in the US is 470 million acres.

X. Coordinated CFB Equipment and Permitting Equipment Needs for Co-Firing - Black & Veatch

Mike King and Diane Fischer of Black & Veatch reported on the regulatory drivers, fuel issues, and emissions controls for co-firing plants. Regulatory drivers include PSD rules, MACT rules, NSR letters, renewable portfolio standards, NAAQS rules, and state environmental rules. For new units, two examples include the Virginia City Energy Center (CFB) and the Yellow Pine Energy project. The Virginia project has 2 small boilers with an SO2 limit of 0.022 lb/MMBTU, a Nox limit of 0.07 lb/MMBTU. These are very tight limits. The Yellow Pine (BFB) project has an SO2 limit of 0,014 lb/MMBU and a NOx limit of 0.10 lb/MMBTU. These limits are for new units, but will influence existing units if retrofits are contemplated. The new Boiler MACT rules are due July 15, 2009. It will include major sources and area sources. It is expected that surrogates will be used and will include particulate matter, HCl, mercury, and CO. The particulates are for heavy metals. The CO is for organic HAP. Fluid bed boilers can burn a variety of fuels. These fuels create a variety of flue gas constituents after combustion. Detailed analysis of fuel constituents will serve as a starting point for emissions control equipment. Ash content, moisture content, sulfur content, chloride content, heavy metals, and alkalies are all important factors in considering the emissions control systems that will be required. Fuel samples for as many fuels as possible are desirable. Detailed analysis of the fuels is better (proximate, ultimate, ash, and trace element analyses). The sample amounts should be such that they are statistically significant. For CFBs, a polishing scrubber is now a requirement on new units. Emission limits on HCl may turn out to be a bigger driver on the control system than the SO2 when high levels of biomass are used. Typically, semi-dry scrubbing systems are being utilized. In these systems, the sorbent material ends up above the dew point of the gas. Duct injection units are cost effective for smaller units or very low sulfur units. Spray dryer systems with a baghouse can achieve better performance and are applicable to larger units. A circulating dry scrubber recirculates the absorbent material. The flash dryer absorber (NID System) achieves a similar objective by using duct injection with sorbent recovery and re-wetting. At the moment, SNCR is still being allowed for the CFB units for NOx control. The permit process is heading towards SCR. Fuel constituents will play a major role in the cost of the SCR system. A high dust SCR is used prior to the air heater. The tail end SCR requires flue gas reheat in order to get the gas temperature up to the operating temperature of the SCR. The applicability of SCR to fluid bed boilers is still in question. It is highly fuel dependent. Particulate loading and catalyst poisoning are potential problems. The tail end SCR uses a regnerative air heater for gas reheat. A regenerative SCR is being sold by Babcock Power which is designed to lower the cost fo reheat. In this system, a regenerable heat recovery bed is used in combination with a catalyst bed in a manner similar to a thermal oxidizer. The gas goes over the hot bed and then the catalyst bed. The hot gas then passes over the other side of the heat pick up to give up its heat prior to going to the stack. Periodically, the gas flow is switched so that the hot bed now sees the entering gas. Some natural gas is fired between the two beds to assure that the gas temperature entering the catalyst is correct.

XI. Tube Leaks and Air Leaks Panel - Moderator - John Malloy - AC Power Colver

The panel consisted of Alex Bonnington, Constellation Energy; Ian Hall, Integrated Global Services; and Fred Farabaugh, AC Power. Alex Bennington reported on fluid bed boiler tube failures and damage mechanisms. Alex presented 4 case studies. The first was a reheater tube failure at the Colver Power Plant. This plant is a 110 Mw CFB burning waste coal. The reheater is at 1005 F and 650 psi and made of SA 213 T22. The reheater did not fail, but was experiencing some unusual characteristics. After 100,000 hours service, the tube was pulled for samples. A thick, internal, iron oxide scale was observed. Some coal ash corrosion was observed on the outside. There was significant high temperature oxidation. It was estimated that the tube was operating at a temperature that was over 100 F greater than design. Creep failures could be expected in the near future. By looking at the oxide layer thickness and the time in service, a prediction could be made about the remaining life of the material. In this case, perhaps another year might have been left on the tube. Another sample in a different section of the same reheater showed a much thinner scale and less corrosion. This calculation indicated that over 11 years life was remaining. Thus, the entire reheater did not need to be replaced. At the Chinese station in California, the finishing superheater experienced several failures after 3 years of service. The original material was T22 that only lasted one year. It was replaced with 310 stainless steel. The first replacement lasted 11 years. The second batch lasted only 3 years. The tube was substantially corroded. Deposit analysis showed chlorides, sulfides, calcium, potassium, and sodium. The high levels of chlorides indicate chloride corrosion. The existence of alkalis put low melting chloride salts on the tubing which provided the starting point for the corrosion. The finishing superheater was replaced with a bundle that had the top two rows clad with Inconel 625. This material is still in operation, but long service is still to be demonstrated. At the Rio Bravo unit, waterwall erosion was experienced. Due to high volumes of entrained ash, waterwalls are subject to erosion damage. Damage is often located directly above the refractory lining. The original material was SA-178C. The wall was previously repaired with SMAW 7018 stick electrode weld overlay. A cross section through the failed tube showed veins of elemental copper. If a tube has experienced thinning and then is weld overlayed, the copper from the feedwater train that remains behind on the inside deposit can be melted and drawn into the grain boundary. The tube might not be burned through, but the effect is the same. Tubing less than 0.1 inches thick should not be welded. At the Rocklin plant, the vortex finder was missing about 30% of the plates from the bottom ring and 10% of the plates from the second ring. The top rings appeared to be OK. The bottom rings were a proprietary alloy. Visual examination revealed extensive corrosion damage. The material was a 20 Cr-10 Ni alloy. The nearest commercial material to that mixture indicated a maximum operating temperature of 1600 F. The upper plates were a 25 Cr- 25 Ni - 1.5 W material which survived reasonably well. This material was indicated to be good to 1900 F. A year later, the middle plates failed. It was found that a 3rd material had been used. The material had good high temperature resistance, but the strength was not acceptable. The material experienced creep in operation. The lugs bent and allowed the plates to fall into the unit. The plate material has to consider both the corrosion aspects and the creep strength for proper service.

Ian Hall of Integrated Global Services reported on waterwall reliability, restoration, and protection. There are 3 main approaches to surface protection. These include thermal (or metal) spray, ceramic paints, and weld overlay. Thermal spray technologies have developed into two types. The first is a gun with a wire feedstock. The compressed air blows the melted wire onto the wall. The material freezes when it hits the wall. The powder system uses a high temperature flame to melt the powder and move it to the wall. This material does not fully melt, but softens to the point where it sticks to the wall. These approaches attempt to change the metallurgy at the surface of the wall, rather than to build up a sacrificial material on the wall. A relatively thin coating is applied. Material selection is dependent on erosion rates, fuel types, corrosive species, installation time, outage history, and budget. Erosion tests show that the wire material does not really hold up as well for erosion. The high tungsten carbide/cobalt carbide sintered material shows the best resistance. The weld overlay approach builds up material on the surface that can be sacrificial. Cored wire materials tend to allow good build up of material that adhere well and are pre-stress relieved. However, these materials tend to have “ built in cracks ” . These cracks allow corrosive species to penetrate the coating. These sprays are better for erosion resistance than for corrosion resistance. This material would need a sealant spray to keep such corrosive species out. Weld overlay is used to increase wall thickness and to increase estimated tube life. Good surface preparation is a requirement. Grinding that smooth and then putting on the thermal spray can serve to restore the tube thickness and provide future resistance. Welding methods include TIG (GTAW), stick (SMAW), MIG (manual), and MIG (automatic). Although stick welding is popular, there is a risk of burning through a thin tube. TIG is good for small areas and used to pad weld a thin tube or a small leak. The stick weld is good for a few square feet and is typically ground to match the rest of the wall. Typical MIG uses a relatively small wire for up to 10 sq. ft. Automated pulsed MIG uses a larger diameter wire and good for larger areas (greater than 10 sq. ft.). Carbon steel is generally good for most applications, but 309 stainless can be used for mild corrosion and IN625 can be used for higher corrosion levels.

Fred Farabaugh of AC Power Colver reported on an air heater case study. The typical air heater for a PC unit is a regenerative unit that rotates material from the hot gases to the cooler air and then back to the hot side. Due to the higher air pressures needed for fluid bed unit, tubular air heaters are often used to minimize any leakage. Tubular air heaters can suffer from cold end corrosion due to cold air entering against cooler flue gas with SO3 in the flue gas. In some cases the dew point is reached and acid gases are condensed which cause corrosion. The condition is aggravated by the amount of flyash passing over the tubes. To avoid corrosion, an air heater bypass was used until the gas temperatures increased to operating temperature. Better materials for the tubing (T11 or T22) were recommended. Steam coil heaters were to be used for very cold weather. Keeping the heater clean any time the unit is down is helpful. The better materials were not really successful. Partial replacement and sealing sleeves did not provide any better results. Using eddy current testing during an outage, full bundle replacements, and cleaning help to keep on top of the problem. Thermal spray coating has been applied as a test on several tubes. Thermocouples were added to tubes and tube sheets to determine low temperature conditions.

XII. CFB Ash Management in Pennsylvania - Keith Brady and Ron Hassinger, PA DEP

The TVA had an ash dam failure during the winter. The new EPA administrator has promised to come up with new regulations for " combustion byproducts " . In the meantime, the State of Pennsylvania has been overhauling its rules on beneficial uses of coal ash. Keith Brady of the Bureau of Mines and Reclamation pointed out that 11 million tons of ash has been used for beneficial purposes per year. This represents a major savings over landfill practices. New policies and regulations are needed as the current set is confusing and antiquated. Monitoring requirements need to be brought up to modern standards. There is constant public scrutiny and high level national interest. The National Academy of Sciences report indicated that there were more chemicals to be monitored and new technology to provide better data. In Pennsylvania, coal ash that is not beneficially used, is considered a waste. Coal ash that is beneficially used is not considered a waste. Revisions to the program now will have their own chapter and will incorporate Technical Guidance. Draft regulations can be found on the state DEP web site. Coal ash is used for mine reclamation and other beneficial applications. A 2 step process is envisioned. A source approval will come through the state offices in Harrisburg. The site approval will be by district. The centralization will improve consistency in review and approval. Regular samples and volume reports will be required. Tracking of sources and better quality control are anticipated. Certification will be the responsibility of the generator. The material will be tested on the generator site. The ash needs to be characterized and to meet quality parameters. The material must be coal ash and not mixed with other waste. Testing will be done at the generator site. The mine site approval process looks at the number and location of monitoring wells, chemical analysis of the water, proper collection techniques, and consistent results. Sampling will be done quarterly. When other materials are burned with the coal, the result is not coal ash and is disposed as waste. A general permit is needed. For small amounts of additional material, the beneficial use can still be allowed.

XIII. Limestone Utilization - Case Studies

Michael Riley of California Byproducts reported on operational modifications to a Pyro Power CFB to reduce limestone usage. The Grant Town Power Plant in West Virginia is operated by Edison Mission O&M and consists of 2 x 400 kpph with about 80 MW total output burning bituminous gob. The limestone was about 79% $CaCO_3$ with about 20% inerts. The design Ca/S ratio was 2.4 for 90% sulfur reduction. The variables affecting limestone consumption include limestone size, reactivity, excess air, injection location, sulfur content, bed temperature, and residence time. The specification size for the fuel was actually coarser than the actual fuel. The lowest cost fuel had a substantial amount of fines. The power purchase agreement (PPA) had penalties for both over and under production. Thus, fuel cost was a major concern. The limestone was ground on site. The design spec was again violated because the mill had to be slowed down due to relatively high moisture with the limestone. The slower mill speed caused a finer grind. As a result, the Ca/S ratio increased to 4.5. Initial studies suggested that the fuel and limestone had to be brought to spec, the air distribution needed improvement, and the bed nozzles to be changed. The plant decided to add a vortex finder as well. The Ca/S ratio went down to 3.6. The change in bed nozzles caused more problems and were changed back. It was nearly impossible to meet the fuel and limestone spec with respect to fineness. With no capital budget and increasing costs, the operations were reviewed. The excess air was reduced to its most efficient setting. The oxygen level was reduced to 2.5%. Fuel and sulfur were adjusted. The continuous emissions monitor was checked regularly for drift. This reduced the call for limestone as the drift was in the wrong direction. The fuel input rate was studied to get the plant to its best efficiency. The inlet to the cyclone was modified with the addition of a " bull nose " . The grinding speed was reduced from 95 rpm to 45 rpm to reduce maintenance cost. The mill dust collector bag material was changed allowing the mill air flow to increase and improve the mill cyclone cut. The cyclone discharge rotary valve drive was replaced with a VFD (variable frequency drive) to reduce surging pressures in the product conveying line. The limestone was a waste product called limestone sand. The top size of this material was reduced. The controllers to the rotary feeders were improved, which prevented overfeeding conditions. The fuel feed system was modified to include bin vibrators and high chrome steel bins (rather than Tyvar lined bins). A splitter box was added to balance the fuel flow. Once the fuel flow was balanced and stabilized, the limestone consumption was reduced. Overall, the improvements reduced the limestone consumption by 50%. One unexpected result was that the reduced limestone use caused an increase in the silica level in the bed ash. The increased silica caused additional tube wear and eventually increased tube leaks.

Howard Fitzgerald of Chemical Lime reported on lime kiln dust opportunity sorbent test results at Twin Oaks Power FBC. In the process of calcining limestone, there are potential " by products " called limestone fines and lime kiln dust. The limestone fines are fine limestone particles that escape the kiln without calcining. The lime kiln dust is a fine dust that has been calcined. Limestone quality is important for a variety of products ranging from specialty papers and fillers to scrubber and FBC additives to Portland cement. If good quality limestone is too expensive, the fines or kiln dust might be used. The lime kiln dust is typically 50 - 70% $CaCO_3$ equivalent from a baghouse. There is 10 - 50% available CaO. Full scale testing has been carried out at the Twin Oaks Power Plant in Texas. The units are 2 x 175 Mw CFBs firing lignite with 1.1% S. The kiln dust was injected at a rate of 25% of the limestone feed rate. The SO_2 removal increased from 70% to 90%. The excess SO_2 allowances were sold on the market. The good results lead to a second, more controlled, test. The kiln dust has a relatively higher percentage of calcium due to the " free lime " available as CaO. The plant fired about 130 ton/hr of coal and about 13 ton/hr of limestone. Tests were done with kiln dust only. Due to the increased calcium level, only 7 ton/hr of dust were added. In both cases, the Ca/S was about 2. One particular kiln dust that had more available CaO increased the overall utilization such that the Ca/S was down to 1.7. Looking at the lb SO_2 removed per pound of additive showed increasing numbers with the kiln dust. The cost/ton of SO_2 was reduced from $61/ton down to a range of $52 - 54/ton. The Twin Oaks plant is continuing to utilize and test the application of kiln dust for longer period operation.

Bill Pollock of NALCO Mobotech reported on the ROFA/ROTAMIX system. The

ROFA is a rotating overfire air system. The ROTAMIX is an SNCR version. The MerControl is a new mercury capture system. These systems are intended to improve the overall operation of the CFB including CO burnout, excess air, SO2 and NOx reduction, and sorbent injection rate. The goal is to provide some additional control in the middle of the furnace. Large, adjustable nozzles injecting high pressure air about half way up the furnace provides for a rotating flow to improve mixing in this region, giving a more uniform outlet condition for all components. As these nozzles are adjustable, changes can be made to optimize the outlet conditions. Since the total amount of air is still the same, the velocities in the dense bed portion are somewhat lower. Incremental SO2 reductions up to 60% have been observed. With the combination of ROTAMIX, incremental NOx reductions up to 72% have been observed. Longer term operation is needed to verify that wear issues or other long term issues are not impacted. The addition of halogens to the gas improves the mercury capture by as much as 90%. In addition to emissions reductions, the overall efficiency of the system can be improved (excess air reduction, additive reduction). Heat rate measurements at one unit indicated a reduction in heat rate from the 10,000 BTU/kwhr level to the 9700 BTU/Kwhr level. A dry system for fuel improvement is being developed. A magnetic separator after a pulverizer takes out some ash with sulfur and heavy metals. The BTU recovery was 94%. The reduction in ash and heavy metals was on the order of 60%. The idea is to improve the quality and consistency of the fuel. The rejects can sometimes be blended with the fly ash. If the heavy metals are too high, separate disposal would be needed.

XIV. Panther Creek Plant Tour - Richard Gawel, Plant Manager

Panther Creek is located in Nesquehonking, PA. The plant has 2 Pyroflow CFBs rated at 380,000 lb/hr firing anthracite culm. The steam turbine is a 90 Mw Alstom machine. The fuel is 6,000 BTU/lb culm with 45% ash, 12% moisture, and 0.4% S. Limestone consumption is relatively low. Fuel is purchased from up to 15 different sources. Originally the fuel was not blended, leading to a wide variation in fuel heating value. The SNCR system uses anhydrous ammonia. The unit is required to monitor and report CO. The plant has its own 31 mile transmission line to interface with Metropolitan Edison. The plant operates on an 18 month outage cycle. Turbine hauls are every 7 years. There is no planned outage every 3rd year. Extensive thickness checks are done throughout the furnace and backpass. The outages focuses on 18 months of reliable operation. The boilers are mapped throughout the system to make sure the units can survive for the next 18 months. Capacity factor is the key to success. The plant needs to run at 100% load all the time. Although efficiency is important, reliability is critcal. Capacity factors for the 3rd year (no outage) were 100.4% in 2003 and 98.2% in 2006. Thus far in 2009, capacity factor is 100%. The overall average was over 95%. For the tubular air heater, a more efficient method to replace air heater tubing was developed to minimize down time. In the early days of operation, there were tube leaks. Thickness mapping and shield installation have reduced this problem. The last leak was in 2007. The prior leak was in 2004. All bends in the back pass have shields. Over time, the controls have been upgraded. Variable frequency drives have been installed. Ash and fuel conveyors were upgraded. Safety valves were flanged so that they can be replaced with new pieces. The old valves can then be repaired off line. Alternate sources of cooling tower water were developed. The plant makes full use of predictive and preventive maintenance techniques. Practical techniques are used to determine whether to “ cut and replace ” or to measure and evaluate.

Carl Bozzuto