The Fate of Ammonia and Mercury in the Carbon Burn-Out (CBO™) Process

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INTRODUCTION

Carbon Burn-Out (CBO™) has long been known as a very robust system for carbon removal for various types of ash feed stocks. Ash feed stocks with carbon contents ranging from 7% to 90% have been successfully processed. To date, over one million tons of coal fly ash have been processed using CBO™.

CBO™ processed coal fly ash exhibits excellent pozzolanic activity, consistent air entrainment, consistent LOI at 2.5% or less, and has gained excellent market acceptance.

Recently, there has been much discussion in the fly ash industry about the fate of ammonia and mercury on fly ash. These two parameters are present in coal fly ash via different mechanisms. Mercury is inherent to the coal while ammonia originates from post-combustion NOx reduction techniques using ammonia.

Ammonia on fly ash is primarily a result of recent pollution abatement techniques. Coal fired power generation facilities are under increasing pressure for NOx emission reductions. Recent United States EPA rule changes will require many coal fired utilities to meet NOx emissions limitations of 0.15 lbs./MBTU or less. In order to meet these requirements, many utilities will use a combination of combustion management and post-combustion processes. Combustion management techniques include low NOx burners, over-fire air systems, gas re-burning technology and flue gas re-circulation. These methods can contribute to higher residual carbon levels in fly ash, especially when operating for maximum NOx removal.

Post-combustion processes include Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR). Use of either of these treatment technologies will result in fly ash contaminated with ammonia slip, which may then be un-marketable, depending on the concentration.

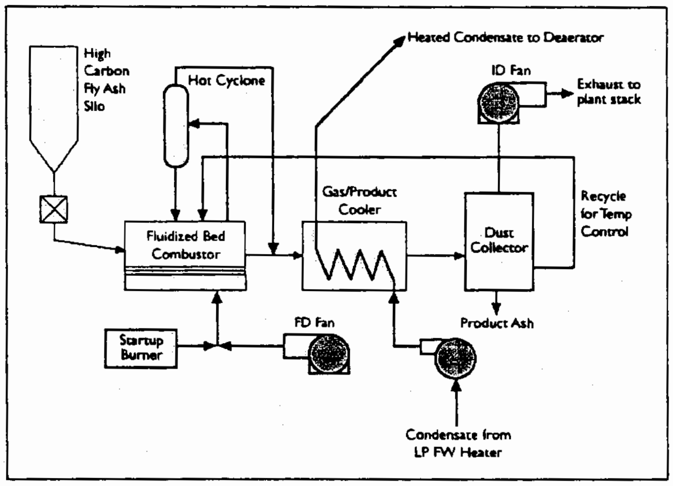
Mercury on the other hand is inherent or naturally occurs in coal. The average value for fly ash from Bituminous coal combustion is .41 ppm[1].

Given the industry's concerns, Progress Materials recently conducted investigations as to the fate of ammonia and mercury in the Carbon Burn-Out process. This paper presents recent findings concerning ammonia and mercury in the Carbon Burn-Out process.

THE CARBON BURN-OUT PROCESS

The Carbon Burn-Out process is a thermal process specifically designed for the reduction of carbon in fly ash.

FIGURE 1: CBO™ Process Diagram



Referring to Figure 1, the CBO™ process flow may be easily summarized:

- High-carbon ash is pneumatically transported to the high carbon fly ash silo.
- FD fan provides fluidization and combustion air to CBO™ fluid bed combustor.
- Start-Up Burner is used only during start up to heat bed to ignition temperature.
- High Carbon feed ash is metered into the combustor.
- Carbon combusts in the FBC on a continuous basis.
- Hot cyclones remove most elutriated particles from FBC flue gas.
- Low carbon fly ash exits FBC via level control weirs.
- Flue gas pneumatically conveys low carbon fly ash, both at about 1300° F through the Gas/Product Cooler.
- In the Gas/Product cooler, heat transfer occurs from hot product ash and hot flue gas to the condensate from the power plant.
- Product ash and flue gas exit at < 300° F.
- Heated condensate returns to power plant's feedwater heater system.

- Product ash is separated from flue gas via cyclone and baghouse.
- ID fan maintains entire CBO™ system at a slight negative pressure, transports product ash through the heat exchanger, and transports cooled, particulate-free flue gas to power plant stack.
- Product ash is pneumatically conveyed to storage for subsequent load out.
- Product ash is also recycled for FBC temperature control.

AMMONIA AND THE CARBON BURN-OUT PROCESS

Progress Materials' ammonia removal investigation approach was developed to accomplish two primary goals. The first goal was to determine Carbon Burn-Out's efficiency in removing ammonia from fly ash. Data would be generated to determine fly ash ammonia concentrations after Carbon Burn-Out processing. The second goal was to determine the fate of the ammonia in the Carbon Burn-Out process. This investigation step involved measuring gas phase ammonia concentrations thereby providing information as to whether the ammonia is exhausted or thermally decomposed within the CBO™ system.

This work on the fate of ammonia in the CBO™ builds on the work previously reported by PMI [2].

Ammonia Testing Procedures and Results

In order to determine the effectiveness of ammonia removal by Carbon Burn-Out, several fly ash feed stocks of differing ammonia contents were processed. Processing was accomplished using Progress Materials' one ton per hour pilot facility located in Tampa, Florida.

Ammonia containing fly ash samples from several Eastern United States utilities were selected for processing. Fly ash ammonia concentrations ranged between 50 and 750 ppmw. Ammoniated fly ash used in this study was generated in both SCR and SNCR systems. Ammonia or Urea was used as the process reagent.

Carbon Burn-Out's fluid bed technology provides heat and residence time dictated by conditions for optimal combustion of carbon found in fly ash. Fly ash residence times of forty-five minutes and temperatures in the 1300°F range are characteristic of the CBO™ process. Kinetic theory suggest that CBO™ conditions should be ideal for ammonia removal and decomposition.

Both feed and product samples were analyzed for ammonia content. Ammoniated fly ash was tested by several different methods. Testing methodology for ammonia in fly ash is not well defined. However, well-defined methods have been used for solid matrices in environmental testing. EPA methods 350.2, 350.3 and a rapid field technique developed by Boral Materials Technologies Inc. were selected for use in our testing program.

Table 1 illustrates results of four different, as-received fly ashes tested using the three methods. EPA methods 350.2 and 350.3 produced similar results. EPA 350.2 uses an aggressive acid distillation step while method 350.3 uses only distilled water for the dissolution of ammonia. The similarity of results between the two methods indicates that the ammonia is water-soluble. The Boral method, which is a simpler-to-run field test, also produced reasonably similar results.

Table1: Ammonia Method Comparison

	EPA 350.2 (PPM)	EPA 350.3 (PPM)	Boral Procedure (PPM)
Sample 1	300	306	320
Sample 2	351	300	250
Sample 3	534	660	525
Sample 4	735	610	720

Table 2 illustrates ammoniated fly ash samples before and after processing by Carbon Burn-Out. Ammonia content of the feed and product, type of NOx control device used and NOx reagent are shown.

Table 2: Ammonia in Fly Ash Feed

Feed Ash (PPM)	Product Ash (PPM)*	Control Device	Reagent
60	< 5	SCR	Ammonia
230	< 5	SNCR	Ammonia
300	< 5	SNCR	Ammonia
500	< 5	SNCR	Ammonia
650	< 5	SNCR	Ammonia
700	< 5	SNCR	Urea
735	< 5	SNCR	Urea

* < Indicates detection limit of the method

Results indicate that under normal Carbon Burn-Out operating conditions essentially all ammonia was removed from the fly ash feed material.

The second goal of the study involved the determination of the fate of released ammonia in the flue gas. To quantify the extent of thermal decomposition of ammonia, flue gas ammonia concentrations were measured at the fluid bed exhaust and the exhaust stack.

The test method selected for ammonia concentration in flue gas was EPA CTM 027, "Procedure for Collection and Analysis of Ammonia in Stationary Sources."

Sampling was conducted after the CBO™ system achieved steady state operation and recycle ash was used for FBC cooling. Such conditions closely simulate large scale CBO™ operation in the pilot facility.

Results of testing indicate that between 94% and 98% of the ammonia introduced into the system is being thermally decomposed. That is, the mass of ammonia in the FBC flue gas was between 4% and 8% of that in the feed ash. Both sampling points produced similar concentrations and decomposition efficiency.

MERCURY AND THE CARBON BURN-OUT PROCESS

Mercury as a trace element in coal is now coming under increasing investigation, particularly as a contaminant in flue gas from coal-fired power plants. Technology is being developed to capture mercury (Hg) contained in this flue gas.

Processes that absorb mercury from the flue gas by injecting carbon (typically activated carbon) into the gas ducting show significant promise. In these processes, the mercury containing carbon may be captured with the fly ash by existing particulate control devices. These processes report capture rates of up to 90% of the total Hg contained in the coal. The relatively small amount of carbon used in mercury capture is co-mingled with normally occurring fly ash.

Addition of even very small amounts of activated carbon to fly ash can reduce the value of the fly ash as a pozzolan used in concrete manufacturing. Activated carbon has been found to interfere greatly with the air entrainment reagents used in concrete mix designs[3].

While most of the regulatory effort has been on removing mercury from flue gas, the presence of mercury on either fly ash or on mixtures of fly ash and activated carbon slated for disposal is of significant concern. This scenario has the potential to change once marketable fly ash into a solid waste.

It was clear that the CBO™ process would combust the small amounts of activated carbon, along with the carbon in the co-mingled ash, and that the mercury would be vaporized at the FBC temperature. What was not clear was what the final fate of that mercury would be. One possibility was that it could simply remain in the vapor state and exit the CBO process in the flue gas. However, since the flue gas is cooled in the G/P Cooler, another possibility was that some fraction of the mercury would condense on the product fly ash and become sequestered when the fly ash was bound in the concrete matrix.

Mercury Testing Procedures and Results

A testing program was designed to determine the fate of mercury in the CBO™ process. A commercial scale CBO™ system was used for this testing program. Fly ash processed in this study was from a utility boiler without activated carbon mercury control equipment so the mercury represents only that captured by the fly ash. Various studies indicate that this can represent 30% to 100% of the total mercury from the coal. [4,5]

Table 3 illustrates sampling points used in this program, sample matrix and the sample type

Table 3: Mercury Sampling Locations

Sampling Point	Matrix	Sample Type
Fly Ash Feed	Solid	Grab
Fly ash product	Solid	Grab
Fluid Bed	Solid	Grab
Hot cyclone Inlet	Gas, Solid	Ontario Hydro
Hot Cyclone Outlet	Gas, Solid	Ontario Hydro
Baghouse Inlet	Gas, Solid	Ontario Hydro
Baghouse Exhaust	Gas, Solid	Ontario Hydro

A mercury balance of the CBO™ process was constructed by examining the mercury concentration of the high carbon feed, low carbon CBO™ product and the exhaust gas of the CBO™ system.

Table 4 illustrates the results of this approach. Three separate runs were used to determine the CBO™ system mass balance for mercury. The data shows excellent mass balance recovery ranging from a low of 94% to a high value of 109% with the average being 101%.

As the data indicates, virtually all of the mercury entering the CBO™ system on the high carbon fly ash feed is found on the low carbon fly ash product. Only .02% of the total mercury entering the CBO™ process is found in the exhaust gas of the system. The remaining 99.98% of the mercury entering the CBO™ process on the high carbon fly ash exits the system with the low carbon CBO™ fly ash product.

Table 4: <u>Mercury Mass Balance for CBO™ Process</u>

Run	Hg-Feed Mg/hr	Hg-Product Mg/hr	Hg-BHO Mg/hr	Prod+BHO Mg/hr	Material Balance %
1	13159	12395	12	12407	94
2	9899	9778	19	9797	99
3	11193	12119	37	12156	109
Average					101

Considering the operational temperatures of the CBO™ process, normally in the 1300° F range, one would assume that mercury would volatize and might exit the CBO™ process in the vapor phase. Indeed, fly ash samples taken from the fluid bed contain essentially no mercury. However, the mass balance information presented in table 4 does not support the assumption that mercury exits the CBO™ system along with the flue gas since virtually all the mercury introduced into the process exits "particulate bound" with the low carbon CBO™ product material.

Mass balance information in table 4 suggests that mercury volatization and a subsequent absorption/adsorption process is taking place within the CBO™ process. In order to develop an understanding of this mechanism speciation data was examined from several Carbon Burn-Out sampling points.

Table 5: <u>Mercury Particulate/Gas Data</u>

				-------Vapor Phase-----	
Sampling Point	**Matrix**	**Sample Type**	**Particulate**	**Oxidized**	**Elemental**
Fly Ash Feed	**Solid**	**Grab**	100%		
Fluid Bed	**Solid**	**Grab**		>96%	
Hot Cyclone Inlet	**Gas, Solid**	**Ontario Hydro**		>96%	
Hot Cyclone Outlet	**Gas, Solid**	**Ontario Hydro**		>96%	
Baghouse Inlet	**Gas, Solid**	**Ontario Hydro**	99.7%	.2%	.1%
Fly Ash Product	**Solid**	**Grab**	100%		

Combining the results presented in Table 5 with the CBO™ process diagram (figure 1) the fate of mercury in the Carbon Burn-Out Process becomes clear. Mercury enters the CBO™ process in the high carbon feed material. Mercury contained with the feed is on the particles of the fly ash.

The fly ash is then metered into the fluid bed combustor and subject to temperatures in the 1300°F range and residence times approaching 45 minutes. In the fluid bed combustor, the mercury is volatized and exits the fluid bed in the vapor state, existing as either the oxidized or elemental form.

The mercury free, low carbon fly ash product exiting the fluid bed is combined with 1200°F to 1300°F flue gas from the hot cyclone. At this point in the process, the hot cyclone exhaust gas contains essentially all of the mercury.

The combined stream of mercury laden flue gas from the hot cyclone discharge and mercury free fly ash exiting the fluid bed enter the gas/product cooler. The combined stream is then cooled from 1100°F to 300°F and subsequently collected by the cold cyclone and baghouse for storage or shipment.

The speciation data shows that fly ash efficiently captures the mercury as the hot fly ash and gas stream pass through the gas product cooler and cold cyclone. By the time the gas stream enters the baghouse, the final particle collection device of the CBO™ process, mercury is particulate bound.

Fly ash enters the gas/product cooler virtually mercury free and by the time it exits the low temperature cyclone, the mercury that was entrained in the flue gas is efficiently transfered to the fly ash. The conditions associated with the G/P cooler and cold cyclone are ideal for the capture of mercury.

The conditions associated with the G/P cooler and cold cyclone are as follows:

Table 6: G/P Cooler & Cold Cyclone Conditions

	G/P Cooler Inlet	Cold Cyclone Discharge
Fly Ash Carbon Content	2%	2%
Fly Ash Mass Flow	60 TPH	60 TPH
Flow Rate	13,500 DSCFM	13,500 DSCFM
Temperature	1050°F	300°F
Residence Time	1 sec	3-4 sec

CONCLUSIONS

Mercury and ammonia are two environmental parameters of interest for the fly ash industry. Progress Materials has undertaken in-depth studies to determine the fate of ammonia and mercury in the Carbon Burn-Out system.

Results indicate that, under normal Carbon Burn-Out operating conditions, essentially all ammonia is eliminated from the fly ash feed material and decomposed. Fly ash having ammonia concentrations between 300 and 750 ppm were processed and in all cases the Carbon Burn-Out process successfully reduced ammonia concentrations below detectable levels. The Carbon Burn-Out process with operational temperatures at 1300°F and 45-minute solid residence times decomposes the ammonia associated with the fly ash. Thus ammonia air emissions tests found that all but 4% to 8% of the total ammonia from the feed ash was decomposed.

Mercury is inherent to coal combustion and, even without activated carbon injection for mercury capture, a substantial portion of mercury found in the coal remains with the high carbon fly ash used as feed for the Carbon Burn-Out system. Operating conditions of the Carbon Burn-Out process results in mercury being volatized and subsequently absorbed/adsorbed on the fly ash product. Process efficiency for the absorption/adsorption process approaches 100%. Therefore, essentially all of the mercury entering the CBO™ process exits the process attached to the product ash. The product ash is used in concrete so the mercury becomes sequestered in the concrete product.

Testing conditions presented in this paper were conducted on Carbon Burn-Out systems functioning in their normal operational modes. No additional equipment modifications or process changes were made .

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By: Brian K. Schimmoller, Managing Editor

Coal and ash handling presents many problems, but cost-saving and revenue generation opportunties are available to aggressive asset owners.

A necessary evil. That is the term often applied to coal and ash handling at power plants. Such functions are typically not held in high regard because they incur costs without contributing substantially to power production. As a result, management understanding is limited in many cases, and time and attention are focused only when the wheel squeaks loudly enough. Efficiency improvements are available, however, if one is willing to look hard enough, as are revenue opportunities, primarily on the back end in terms of fly ash separation and marketing.

Coal handling is often a complex undertaking, particularly for larger power stations. The delivery route, from the mine to railcar to unloading facility to storage to reclaim to pulverizer, is subject to numerous inefficiencies. The significant increase in use of Powder River Basin coal – from next to nothing in 1970 to about 375 million tons in 2002 to a potential 500-550 million tons by 2010 – has introduced further complexities associated with dust generation, freezing tendency, spontaneous combustion, and the increased volume that must be handled at plants that have switched from eastern coals.

To an extent, however, these complications may be overblown. "Much of what we encounter when we perform handling system audits shows us that little, if any, capital is required to provide meaningful improvements, and these improvements can often occur without increase in operating costs," said Don Samples, Vice President and Senior Consultant with St. Louis-based Marston & Marston Inc.

Stockpiles and Track-laying

Stockpile configuration represents one area in which power plants could achieve some low-cost improvements. Ingrained practices rarely prepare coal-handling personnel to optimally manage the movement of coal from the unloading facility to the stockpile, particularly during unplanned outages. Stockpile configurations are often not planned for cost-effective coal movements and for minimized energy loss, but have evolved into a wrong configuration from "doing it the easy way." If an unplanned outage does occur, or if there is a need to take coal in excess of bum, plants often end up scrambling to get personnel and mobile equipment into action to prevent coal from sitting idle in railcars and backing up trains. Labor and equipment costs spiral, and the entire storage area is often disturbed in a costly and unnecessary way.

In many cases, when several trains are handled in a day, extra holding tracks could remedy this problem and, at the same time, keep train turnaround times to a minimum. "We often find that power plants approach this problem with the wrong philosophy," said Samples. "Extra track capacity enables power plants to handle coal when they want to with available crews rather than when they have to with extra crews." Whether to install extra track is a question that can be answered by a simple demonstration of economics. Is there enough potential benefit to afford the tracks? Modeling can give a good indication.

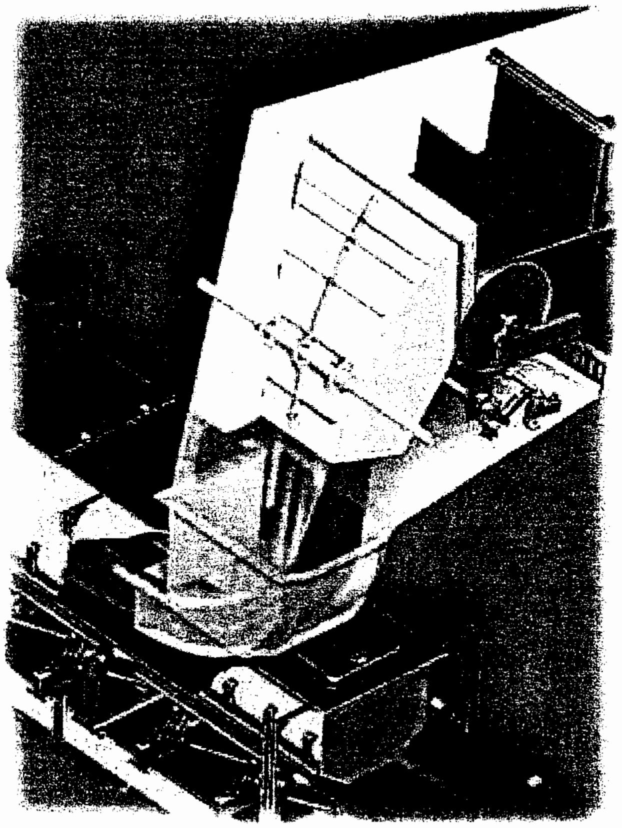
With the growth in demand for PRB coal, effective delivery and turnaround is critical. "There is little if any slack time in deliveries out of the Powder River Basin anymore," said Bob Yarkosky, Marston & Marston Vice President of Engineering Services. "Most large-burn power stations work with suppliers and railroads to structure deliveries as much as12 months in advance." In several cases it has been shown that if just one unit train on a long haul gets backed up at the power plant coalyard for several hours, it can force the side-tracking of five or six others, which forces the railroad, the power station, and sometimes even the coal supplier to reschedule. This result is added costs, expensive delays, and even shortages.

Computer modeling is effective for assessing the value of extra holding tracks, or even changed coal handling practices. Incorporating data related to plant bum, schedules, manning, equipment, number of trains per day, turnaround times and other variables of side-track capacity, crew-change points, overtime, maintenance, etc., users can conduct "what-if" analyses to determine the effect of extra tracks or other changes on train scheduling and costs.

Eventually a point of diminishing returns will be reached, but in the case of extra track, it can often be cost-justified unless nearby sidings are available or the plant maintains an unusually large and reachable stockpile. Obviously, to be cost effective, lower freight or handling costs must accrue to the investor in the new trackage. Samples offers a rough rule of thumb that the number of extra holding tracks should be one less than the average number of train deliveries on a given day.

Same Old Same Old

Because fuel and materials-handling functions can become routine – rarely appearing on upper management's radar screens – there is an inherent tendency for coal managers and operators to continue doing things for convenience rather than for optimum efficiency. Conveyors may run virtually all day long, sometimes impairing routine maintenance, even though bunkers are only being filled six or eight hours per day. Mobile equipment is left on with engines idling for hours without being used. Operators sit idly in equipment when they could be maintaining equipment. "Make-work" often occurs in the coal yard to fill work voids, and this can become instilled as practice, while maintenance or clean-up goes begging.



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Schematic of hood and spoon engineered chute design.
Courtesy of Martin Engineering.

Past practice and complacency can lead to resistance to change and inefficient use of resources. "If a change is proposed – maybe a different coal or an increase in throughput or a new blending program – there is a tendency to believe the only thing you can do is throw capital at it," said Samples. This is simply not true in most cases, and an objective analysis can show it. "The focus has been taken off efforts to ensure low-cost equipment usage." At plants Samples audited over the course of several years, equipment efficiency, in terms of equipment hours per ton of coal, rose tremendously while gross tonnage, and tons handled per hour, went down. The solution to every problem became more people, longer hours and more equipment.

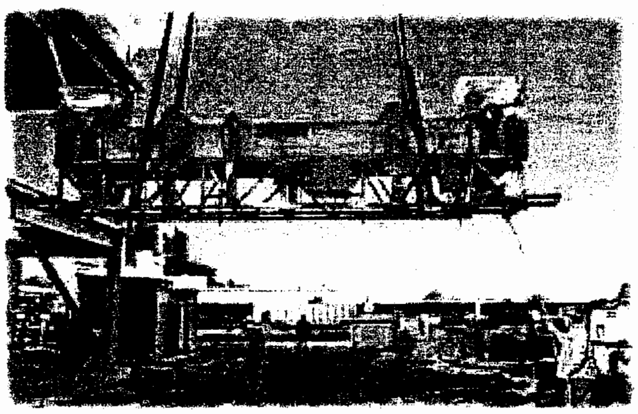
"Larger power plants are often 200-300 percent overequipped on mobile equipment, and this is in excess of ordinary redundancy levels," said Samples. To optimize resource utilization, Marston favors a benchmarking approach in which equipment is analyzed in terms of what it is capable of doing instead of what it is doing. Most plants record a lot of information on equipment operating hours, maintenance hours, manpower levels, etc., but few take the time to analyze it properly. "By reviewing manpower levels, mechanical availability, scheduling practices, stockpile configuration and other factors, for example, the reasons why a dozer or pan can move only 1,000 tph when it's designed for 2,000 tph can be pinpointed and corrective measures implemented," said Yarkosky. This is usually simple to accomplish, and if done right, the new practice is well accepted by the workforce. "In many cases, you'll find that several pieces of equipment see only minimal use and are only there for extra insurance purposes." This compounds what is already an over-redundant staff of machines and personnel.

Dust to Dust

Generating dust during coal handling is unavoidable at power plants. In all cases, dust can be controlled. Where excessive dust levels exist, however, they are typically due to a lack of attention rather than a lack of technology. "Maintaining dust equipment, particularly sprays, is simply not a high priority," said Samples. "However, I haven't seen a single plant where there was insufficient manpower to do normal maintenance and clean-up – generally without overtime – if properly planned and scheduled."

Still, technology can help. Redesigning transfer chutes can reduce dust. Most transfer chutes were designed simply to move material from point A to point B, not to accommodate the movement of coal with minimum dust generation. If the body of moving material is kept "tight," air entrainment is minimized, and dust generation is minimized when the material changes direction or velocity.

Engineered systems that control material as it comes off of a conveyor discharge pulley and then keeps the material tightly together through the drop chute, can minimize air entrainment, dust generation and belt wear. Such "hood and spoon" chute systems also may include seals at the entry point to reduce air movement into the enclosure, and stilling areas and staggered dust curtains to enable dust to settle back onto the belt before leaving the enclosure. Martin Engineering has performed extensive testing of such a hood and spoon system on the material handling equipment at a PRB coal mine in Wyoming and at a power plant in the Midwest, with promising results.



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In late February, JEA began installing an STI electrostatic separator at St. John's River Power Park to beneficiate carbon from fly ash. The separator is expected to go on-line in April. Photo courtesy of Separation Technologies Inc.

At the coal mine, the system was installed on a belt-to-belt transfer where 4,200 tph moved from a 72-inch belt to a 60-inch receiving conveyor with a drop height of 15.5 feet. The previous transfer chute had problems with dust control despite the installation of an extensive baghouse collection system. To test the performance of the hood and spoon system, Martin placed a series of catching pans on the floor adjacent to the transfer point. Table 1 compares the measured dust levels before and after installing the engineered chute design. Fugitive dust loads fell 76 percent and respirable dust loads fell 25 percent, while tonnage increased. Notably, the results achieved with the hood and spoon system occurred without the baghouse collection system in operation. At the power plant, preliminary results indicate greater than 90 percent dust reduction, and dust suppression requirements cut in half.

TABLE 1
ENGINEERED CHUTE TEST RESULTS

	Fugitive material load		Respirable dust load (g)	Material handled (tons)
	Pan (g)	Area (g/m²)		
Before (average of three tests)	207.5	88.75	0.0016	25,910
After (average of three tests)	49.67	21.24	0.0012	29,667
Results	76% reduction	76% reduction	25% reduction	14% increase

Source: Martin Engineering

Click here to enlarge image

Hood and spoon systems do more than reduce dust. Chute wear and belt wear can also be reduced because of the gentler transfer of material from one point to another. "There's no doubt that it's the best technology available for coal handling at transfer points," said Reese Kidman, Manager of Western Operations for Roberts & Schaefer, which has engineered and installed several hood and spoon systems. "The tradeoff is that it's somewhat more expensive because of the higher fabrication costs and the additional engineering costs associated with modeling material flow through the chute." Also, because coal moisture can have significant effects on material handling, Kidman stresses the importance of designing the system to accommodate both a very wet coal stream and a very dry coal stream.

Wheat From Chaff

When discussions turn from coal handling to ash handling, the focus quickly centers on ways to minimize disposal costs and maximize the marketing of combustion byproducts. A ton sold or transferred to a third-party is a ton that does not have to be landfilled. While a "cost-avoidance" philosophy predominates for most lower-value combustion byproducts (e.g., bottom ash and scrubber sludge), a revenue generation mindset is taking root for higher-value products (e.g., fly ash and wallboard gypsum).

While much of the fly ash derived from Western and Midwestern coals is marketable to end users without any dedicated processing, a number of coal-fired power plants burning Eastern coals have turned to beneficiation processes to improve the quality and attractiveness of their fly ash streams. The two most common beneficiation technologies in use are Carbon BurnOut (CBO) and electrostatic separation.

The Carbon BurnOut process, patented by Progress Materials Inc., relies on a proprietary fluidized bed furnace to combust the carbon in the fly ash, leaving a consistent fly ash product for the ready mix concrete market. South Carolina Electric & Gas has had a CBO unit running at its Wateree station since early 1999, and Santee Cooper contracted with The SEFA Group Inc. to bring a CBO unit on-line at its Winyah station in late 2002.

A multitude of factors must be considered to determine if a power plant is a good candidate for CBO, according to Jim Keppeler, Vice President with Progress Materials. The list includes ash disposal costs, environmental restrictions, local and regional ash markets, quantity of available fly ash, LOI (loss on ignition) content, proximity to supply and market, and construction labor costs. Each power plant will have its own circumstances that will affect cost and viability. "Wateree wasn't quite large enough to justify a CBO unit on its own, which is why we had to supplement with ash from three of our other plants and a few non-SCE&G facilities," said Ted Frady with SCE&G. "We also had to invest in a dry collection and load-out system at one of the supplying plants to enable us to get the fly ash into a tanker truck for delivery to Wateree."

The CBO unit at Wateree processes about 220,000 tons of ash per year. Feed LOI levels have ranged from 6.5-18 percent, and fly ash product LOI has consistently averaged 2.5 percent. Blending capabilities have been important in accommodating operating periods during which fly ash LOI levels spike high or low. A lower limit of 9 percent is targeted to ensure enough carbon is in the furnace to sustain combustion; because throughput drops with increasing LOI, an upper limit of 12 percent is maintained. The 2.5 percent target can be achieved consistently regardless of feed LOI. The CBO furnace is started up on light oil or propane until the bed temperature reaches approximately 800 F, at which point the ash auto-ignites. Like a conventional furnace, continuous operation is the preferred mode of operation, although a slumped ash bed can maintain temperature above 800 F for at least 12 hours without requiring a re-ignition start. Because the flue gas from the CBO can be integrated into the power plant's main stack, permitting is relatively straightforward, often via a modified stack permit with a state agency.

A key feature of the CBO technology is its ability to recover heat from the process and improve station efficiency. Both Wateree and Winyah opted to use the heat from the CBO flue gas to preheat feedwater from one of the low-pressure feedwater heater trains. In such a configuration, heavy-walled heat exchangers are not required, and the stream can be returned to the steam cycle ahead of the deaerator at the required temperature and pressure levels. Wateree can trace a heat rate improvement of about 60 Btu/kWh to the CBO unit, according to Frady. Depending on the plant design, other heat recovery options are possible, said Keppeler, including air pre-heating and making steam.

An important lesson learned from the CBO at Wateree is the need for exhaust gas recirculation (EGR). Fluidized bed operators face two main challenges in controlling combustion. The first is controlling the bed velocity at the right level to maintain efficient combustion without blowing off the bed. The second is providing adequate oxygen for combustion. By controlling the amount of oxygen-depleted recirculating exhaust gas, the combustion process can be controlled at an acceptable burn rate (lb C/ft2/hr). If the feed LOI drops, for example, EGR can be increased, slowing the process down so the ash silos don't run empty trying to maintain the same carbon input. With EGR, Wateree can achieve a 2:1 turndown.

Ammonia-contaminated fly ash from power plants equipped with SCR, SNCR or precipitator conditioning systems is not expected to provide any operational problem for CBO units. In pilot testing, feed ash with ammonia levels of up to 1000 ppm resulted in product streams with undetectable ammonia levels. Performance at utility scale, and the reaction of end users, will be demonstrated later this year, when SCR units at Wateree come on-line.

Various ownership and operational arrangements are available with CBO. At Wateree, SCE&G owns the unit, but The SEFA Group operates it. At Winyah, The SEFA Group owns and operates the unit. Various payment options are available, according to SCE&G's Frady, including a monthly fee, or a fixed $/ton figure, and a percentage of the revenues. Power plant owners need to assess which alternative fits best with their business objectives and acceptable risk level. When SCE&G first committed to the CBO unit, it expected a 3-5 year payback period; after four years of operation, Frady maintains that they are on track to meet this goal.

Electrostatic Separation

Fly ash processing via electrostatic separation is an entirely different animal. Rather than combusting the fly ash to get rid of the carbon, a physical separation takes place. Differential charging enables carbon-rich particles to be separated from the low-carbon ash particles, creating two potentially valuable product streams: low LOI fly ash for use in the ready mix concrete market and a carbon-rich material for use as a supplemental boiler fuel or as feedstock for cement plants.

Separation Technologies Inc. (STI), which patented the electrostatic process for power plant fly ash, currently has three plants in operation in the U.S., one in operation in Scotland, and a fourth U.S. plant scheduled for on-line operation in April. The units in operation have an on-stream factor of 90 percent, according to STI. During short periods of downtime for required equipment maintenance, fly ash simply accumulates in silos. STI has identified at least 50 coal-fired plants in the U.S., and another 50 worldwide, as prime candidates for fly ash separation technology, based on an analysis of regional markets for concrete-quality fly ash.

Constellation Energy Group's Brandon Shores Plant has relied on a 35 tph electrostatic separation system (owned and operated by STI) since 1999 to process its fly ash. The system handles a wide range of feed LOI levels, from the low teens in the summer ozone season to around five percent in the non-ozone season. Brandon Shores works very closely with STI. "We share information so that we can supply sufficient ash to STI so they can meet their commercial commitments," said John Strauch, General Manager at Brandon Shores. "In turn, STI works within our maintenance and scheduling constraints, and provides data – including LOI and foam index – that enable us to improve combustion tuning and airflow." Further, although the system only processes the fly ash from Unit 2, Constellation sometimes asks STI for an LOI reading on samples from Unit 1 since STI can measure LOI more quickly.

When JEA's St. John's River Power Park began firing a mix of petroleum coke and coal in 1997 to maintain lower power costs, a higher fly ash LOI level resulted than when burning coal alone. The high LOI level, and high ammonia levels resulting from the ammonia injection system used to buffer the SO3 plume, rendered the fly ash unmarketable in the Jacksonville area. JEA decided to have STI install an electrostatic separation system to upgrade the quality and value of the 300,000 tons of ash it produced each year. "The key benefit to JEA, apart from recycling another plant byproduct, is the avoidance of landfill costs and the extension of the life of our existing landfill capacity," said Paul Smith, plant manager. "For this plant, that savings can amount to more than $1 million annually. In fact, the STI system will almost eliminate all of our landfill costs."

Although several power plants using STI technology have performed extensive testing to demonstrate the viability of recovering the fuel value of the carbon-rich stream, none have allocated the necessary capital to install feed systems to utilize the carbon on a continuous basis. "At Brandon Shores, because of engineering differences introduced when the boilers were converted from oil to coal-fired, there is some concern that the higher ash content of the carbon-rich stream could increase boiler tube erosion," said Strauch. "Further in-depth analysis to measure the impact of this increased ash content, as part of the overall project cost and benefit, would be necessary prior to full-scale implementation." A portion of the carbon-rich material from Brandon Shores, however, is used as feedstock in cement kilns, and JEA is exploring the use of the material at a fluidized bed plant.

The electrostatic carbon separation process is not affected by the presence of ammonia on the fly ash. Two of the plants with STI operations are using SCR systems to control NOx emissions, and no impact on ash quality has been observed. To mitigate potential concerns, however, STI has developed an ammonia removal process that can be integrated with the carbon separator or operated as a stand-alone unit. Small quantities of alkaline compounds and water are added to the fly ash, creating a thin-film solution of high pH on the ash particles that cause the ammonia to be rapidly released under controlled conditions. The final chemistry of the ash is insignificantly changed from the untreated ash.

JEA's St. John's River Power Park will house the first such ammonia removal system, capable of handling up to 40 tph. "If fly ash with elevated ammonia slip is used in concrete, the curing concrete releases strong ammonia fumes that are unacceptable," said JEA's Smith. "Removing the ammonia certainly is a customer requirement. We felt STI had the only fly ash separation technology that could handle the ammonia removal cost effectively and at the high volumes we needed."

Coal and Ash Handling

Historically, the sale of high-quality fly ash into the ready-mix concrete market has received the greatest attention, and power plant operators and third-party marketers have been the primary sales agents. Over the past decade or so, however, a stand-alone ash marketing industry has formed, consolidating many smaller players into larger entities with greater reach and financial resources. Many power plants utilize the services of companies such as ISG Resources, SEFA Group, Mineral Resource Technologies, and others to market and manage fly ash and other combustion byproducts. These companies are adept at identifying buyers, arranging the sale, and managing the myriad logistical details associated with matching ash availability and product specifications with buyer requirements.

Cinergy produces about 5.6 million tons of combustion byproducts each year from its coal-fired power plants in the Cincinnati area. It markets 100 percent of the gypsum, about 50 percent of the fly ash and bottom ash, and a small fraction of the scrubber sludge. In early 2002, Cinergy began using FlyAshDirect (www.flyashdirect.com), a web-based CCP marketing assistance program, to market the fly ash from the Beckjord, Miami Fort and Zimmer power stations.

"Instead of paying a broker, the logistical capabilities at FlyAshDirect enable utilities to market their own products," said Jim Irvine, President of FlyAshDirect. The web site enables potential buyers to access key data pertaining to a given power plant's CCPs: inventory levels, quality specifications, loading instructions, directions to the plant, MSDS information, insurance requirements, emergency procedures, and current weather conditions. Lag time between data availability and on-line posting is about 30 minutes, essentially real-time for CCP marketing.

"I've been amazed by the customer response," said David Beck, Cinergy's ash utilization manager. "Customers are sent updates twice a day via e-mail or fax regarding quality and quantity levels so they know exactly what is going on with fly ash inventories and qualities at our plants." Utilities can pay FlyAshDirect a flat monthly fee for the use of its on-line system, or a revenue split can be arranged. Unique requests can also be accommodated. For example, Cinergy wanted a marketer that didn't represent other fly ash sources in the area, so FlyAshDirect agreed to a certain radius around Cincinnati within which it would not market non-Cinergy fly ashes, according to Beck.

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