How stealth combustion losses lower plant efficiency

At the average coal-fired power plant, the battle to reduce net heat rate is complicated by skin-tight maintenance budgets, staff reductions, and—for some—the switch from baseload to mid-peaking service. Experience indicates that many plants operate at a heat rate as much as 10% above design, and that those plants' inattention to O&M is responsible for the inefficiency. The most fruitful approach to improving a plant's heat rate is to optimize combustion in its boiler, particularly by minimizing the amount of "stealth" air in-leakage.

By Richard F. (Dick) Storm, Storm Technologies Inc.

On September 25, 2004, Widows Creek Unit 3 in Stevenson, Ala., established a new continuous-run record for Tennessee Valley Authority's (TVA's) fossil plant portfolio when it surpassed the 616-day mark held by Johnsonville Unit 3 in Tennessee. At press time in early February, Widows Creek 3 (Figure 1) had pushed that record to 750 days and continues to run strong.

The record is especially impressive considering that the 120-MW unit was built in the early 1950s and was considered by some as past its prime. During last summer's peak demand season, TVA's fossil-fueled plants produced most of the utility's electricity and set a record for reliability with the lowest forced outage rate in TVA history. However, all good things do come to an end: Widows Creek 3 is scheduled for a maintenance outage this spring.

Live long and prosper

As with a car, it's not the age of a plant but rather its upkeep that determines its reliability. TVA's 59 coal-fired units, including the eight at Widows Creek (which is about 50 miles southwest of Chattanooga), supply more than 60% of the utility's load. To make sure these plants remain in tip-top shape, in January, TVA directors approved contracts with Paris-based Alstom Power Inc. and Porter-Walker LLC (Columbia, Tenn.) for up to $400 million worth of equipment, labor, and materials over the next decade. Given that TVA also plans to spend $5.6 billion to cut emissions from its coal-fired plants by at least 75% by 2010, workers' jobs are secure.

When asked to reveal the secret behind Unit 3's record run, Maintenance Manager Steven Standefer cited the plant's "atten-

1. Record-setter. Unit 3 of TVA's Widows Creek Plant recently set a U.S. record for continuous days of operation by a coal-fired boiler. At press time, Unit 3 had accumulated 750 days of operation and was still going strong. *Courtesy: TVA*

tion to complete inspections and preventive maintenance" so problems can be detected early and corrected immediately. The O&M folks at Widows Creek must be doing something right, because Unit 3 hasn't had a tube leak in more than 1,200 days. According to TVA, the previous American record for a coal-fired, single-boiler, single-turbine unit was 712 days and was held by Unit 4 of Toledo Edison's Bayshore Station.

Of course, most utilities lack the deep pockets that have enabled TVA to commit to the aforementioned long-term investments in its facilities. However, experience indicates that significant unit heat rate improvements can be achieved by making a concerted effort to eliminate "stealth" air in-leakage losses. As the list in "Isolating the impact of a change" (p. **TK**) shows, there's no shortage of variables that can be controlled more accurately to reduce heat rate, and many involve air in-leakage. However, what often makes combustion optimization difficult is the fact that many of these variables are interrelated.

The coal-burning community within the U.S. generation industry is well aware of the savings that lower heat rates can produce. In fact, the Electric Power Research

Institute has an ongoing program devoted solely to improving its members' efforts in that regard (see "Heat rate on the industry's radar," page **TK**). Similarly, the purpose of this article is to suggest specific steps you can take to restore your "senior citizen" to its former vitality.

Testing's role in optimization

The most common way to improve the heat rate and capacity factor of a coal-fired plant is to optimize the boiler's fuel and air inputs (Figure 2). Many plants strive to do that, with varying degrees of success. However, the author has noticed from his visits to many coal-fired facilities over the years that most plants running at or near peak efficiency have something in common: a high-value, test-driven maintenance program. Among the procedures such programs call for are leakage testing to improve air heater seal maintenance and frequent testing of the performance of pulverizers (including primary airflow calibrations), to optimize their performance.

Why does optimizing the combustion process have such a big and beneficial impact on a plant's heat rate, capacity factor, reliability, and profitability? One reason is that when the gas temperatures in a boiler's highly stratified upper furnace are running at the design level, the boiler can burn a wider variety of fuels and lower-quality fuels—including some with very low ash fusion temperatures—without slagging or fouling. Furthermore, reducing the number of high gas temperature "lanes" in the upper furnace reduces the potential number of superheater and reheater tubes that can overheat. With fewer tubes to overheat, the plant can stay on-line longer, with beneficial impact on its annual average capacity factor and heat rate.

The impact of optimized combustion on plant economics is likewise beneficial and can be quite substantial. As the table shows, the estimated annual saving produced by lowering the heat rate of a 400-MW coal-fired plant with an 80% capacity factor by 750 Btu/kWh is more than $2 million.
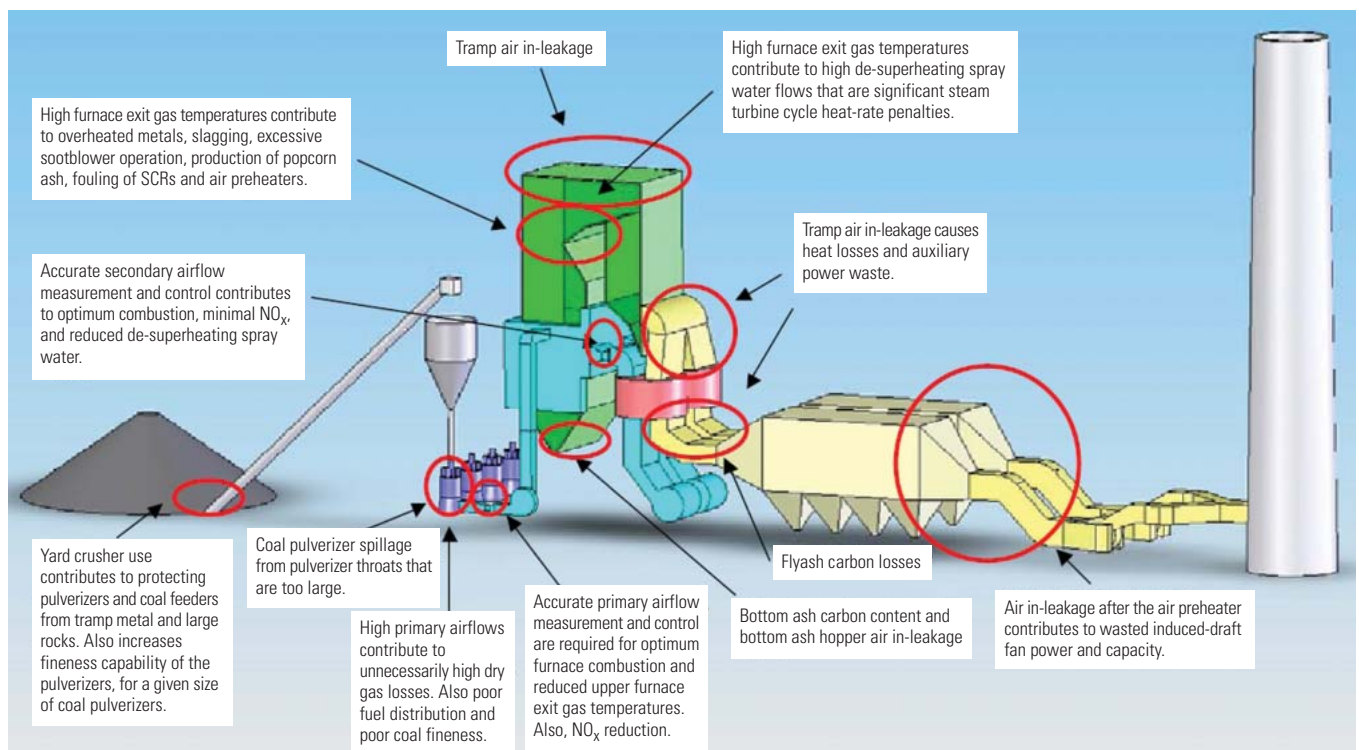
The possibilities for, and payoffs from, improving the heat rate of a 400-MW, 2,400-psi utility coal-fired boiler

Variable	Potential heat rate improvement (Btu/kWh)	Potential annual fuel savings
Boiler and ductwork ambient air in-leakage	300	$819,000
Dry gas loss at the air heater exit	100	$273,000
Primary airflow	75[a]	$204,750
Steam temperature	75	$204,750
De-superheater spray water flow	50	$136,500
Coal spillage	25	$68,250
Unburned carbon in flyash	25[a]	$68,250
Unburned carbon in bottom ash	25	$68,250
Slagging and fouling	25[a]	$68,250
Cycle losses	25	$68,250
All others, including sootblowing and auxiliary power factors	25	$68,250
Total	**750**	**$2,047,500**

Note: a. Interactions between variables will impact meeting this estimate.

Source: Storm Technologies Inc.

---

2. Hard to find. Stealth leakage losses in a typical balanced-draft coal-fired power plant could be responsible for losses in efficiency of up to 10%. *Courtesy: Storm Technologies Inc.*

Tramp air in-leakage

High furnace exit gas temperatures contribute to high de-superheating spray water flows that are significant steam turbine cycle heat-rate penalties.

High furnace exit gas temperatures contribute to overheated metals, slagging, excessive sootblower operation, production of popcorn ash, fouling of SCRs and air preheaters.

Tramp air in-leakage causes heat losses and auxiliary power waste.

Accurate secondary airflow measurement and control contributes to optimum combustion, minimal NO$_x$, and reduced de-superheating spray water.

Yard crusher use contributes to protecting pulverizers and coal feeders from tramp metal and large rocks. Also increases fineness capability of the pulverizers, for a given size of coal pulverizers.

Coal pulverizer spillage from pulverizer throats that are too large.

High primary airflows contribute to unnecessarily high dry gas losses. Also poor fuel distribution and poor coal fineness.

Accurate primary airflow measurement and control are required for optimum furnace combustion and reduced upper furnace exit gas temperatures. Also, NO$_x$ reduction.

Bottom ash carbon content and bottom ash hopper air in-leakage

Flyash carbon losses

Air in-leakage after the air preheater contributes to wasted induced-draft fan power and capacity.

Isolating the impact of a change

As the list below reveals, the typical coal-fired utility boiler has many O&M variables that can be controlled to lower the plant's heat rate (note how many directly involve air in-leakage):

- Pulverizer primary airflow.
- Air heater leakage.
- Boiler and ductwork air in-leakage.
- Pulverizer coal spillage.
- Flyash unburned carbon content.
- Bottom ash unburned carbon content.
- Superheater de-superheating spray water flow.
- Reheater de-superheating spray water flow.
- Superheater outlet steam temperature.
- Reheater outlet steam temperature.
- Air heater exit gas temperature.
- Excess air at the boiler exit.
- Leakage from the boiler vent and drain valves.
- Auxiliary power consumption due to non-optimized combustion, poor tuning, or inattention to maintenance of fans or ductwork.
- Sootblowing frequency and duration.

The fly in the ointment here is that many of those variables are highly interrelated. For example, consider flyash carbon content. If it is high, the cause may be higher-than-optimal primary airflow.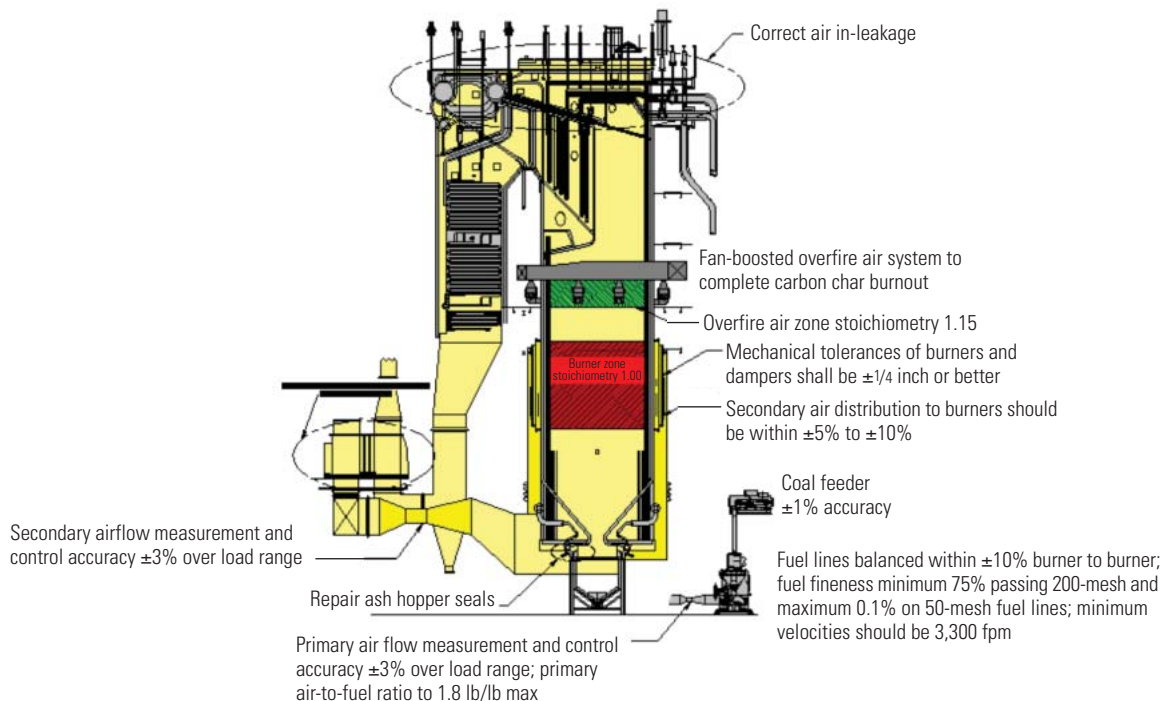 If the boiler in question is burning a bitumi-nous coal with less than 15% total moisture, a high primary airflow would call for a corresponding increase in tempering airflow (Figure 3).

However, raising the amount of tempering airflow above the design level would incur small penalties in both heat rate and boiler efficiency, because the tempering air bypasses the combustion air preheating in the air preheater. One result of the bypassing would be increased dry-gas losses, due to a slightly higher gas temperature at the air heater exit. Another would be a degradation of fuel fineness, because pulverizer fineness is nearly always lower at higher primary airflows.

For another example of the interrelatedness of O&M variables, consider what happens when secondary combustion in the upper furnace (from non-optimal fuel distribution in the burner belt) creates hot zones that are more prone to slagging than cooler zones. Running sootblowers more often to remove the slag deposits incurs a penalty on the steam cycle. What's more, the cinders removed from the high-temperature zones of the superheater or reheater can enter the flue gas stream as popcorn-sized particles of ash that could block the flow channels of a selective catalytic reduction catalyst or foul the baskets of a regenerative air heater.

Fouling does more than just increase draft losses. It also increases the differential pressure between the forced-draft fan discharge and the induced-draft fan suction, which, in turn,

---

3. That giant sucking sound. Sources of air leakage in a typical utility steam generator. *Courtesy: Storm Technologies Inc.*

Correct air in-leakage

Fan-boosted overfire air system to complete carbon char burnout

Overfire air zone stoichiometry 1.15

Mechanical tolerances of burners and dampers shall be ±1/4 inch or better

Secondary air distribution to burners should be within ±5% to ±10%

Burner zone stoichiometry 1.00

Coal feeder ±1% accuracy

Fuel lines balanced within ±10% burner to burner; fuel fineness minimum 75% passing 200-mesh and maximum 0.1% on 50-mesh fuel lines; minimum velocities should be 3,300 fpm

Secondary airflow measurement and control accuracy ±3% over load range

Repair ash hopper seals

Primary air flow measurement and control accuracy ±3% over load range; primary air-to-fuel ratio to 1.8 lb/lb max

4. Testing, testing. A water-cooled, high-velocity thermocouple probe is used as part of a diagnostic test to quantify "oxygen rise," furnace exit gas temperature, and flue gas composition stratification. *Courtesy: Storm Technologies Inc.*

increases air heater leakage. Also, higher draft losses require increased fan drive power for both the increased head as well as for the increased air heater leakage.

The rule of thumb for bituminous coal ash is that a 1% LOI (loss of ignition) improvement is worth about 0.1% in boiler efficiency improvement. However, this loss can be amplified for unit heat rate improvement due to the other interrelationships among potential combustion improvements.

The impact of controlling some O&M variables to reduce heat rate is much more straightforward and easier to quantify. As an example, reducing excessive flue gas temperatures in the extremely hot stratified upper furnace reduces the incidence of individual superheater and reheater tube overheating. Taking that step usually reduces the need for sootblowing as well as the frequency of outages due to tube leaks (Figure 4).

Some don't like it hot

Ready for a crash course in reducing air in-leakage? As a prerequisite, you should know that balanced-draft boilers can accumulate significant quantities of air in-leakage or "tramp" air. Tramp air can leak into the boiler casing, through expansion joints (Figures 5 and 6), into superheater tube penetrations in the boiler penthouse (Figure 7), through the ash hopper, or through torn welds in the welded wall construction. The result is a significant loss of boiler efficiency, caused by high furnace exit gas temperatures.

The tramp air, which contributes nothing to combustion, is discharged out the stack at the stack temperature. In some extreme cases, the amount of air in-leakage at the boiler has been found to be as high as 15% of the equivalent level of total combustion air. The heat rate penalty is even more significant if the tramp air also is leaking into the boiler backpass or economizer outlet flue gas ductwork. The flue gas composition at the air heater inlet flue gas is measured as if the air flowed through the burners and is generally not quantified or detected in an ASME PTC-4.1 or PTC-4.0 boiler efficiency test.

Air in-leakage also can reduce the quality of combustion by lowering the amount of excess oxygen in the furnace (Figures 7, 8, and 9). Low levels of excess oxygen can lead to secondary combustion high in the furnace, which then contributes to higher-than-optimal furnace exit gas temperatures (FEGTs). The higher FEGTs, in turn, contribute to steam cycle losses by increasing the flow of de-superheating spray water into the superheater or reheater above the optimal level. Recall

5. 15% loss. Leaks in an economizer expansion where the level of air in-leakage was about 15% that of total combustion air. *Courtesy: Storm Technologies Inc.*

6. From every direction. "Cupcake" expansion joint leaks at the economizer of a 585-MW supercritical boiler show air in-leakage from four sides and numerous cracks/tears. Total leakage was estimated to be equivalent to 5% of total combustion air. *Courtesy: Storm Technologies Inc.*
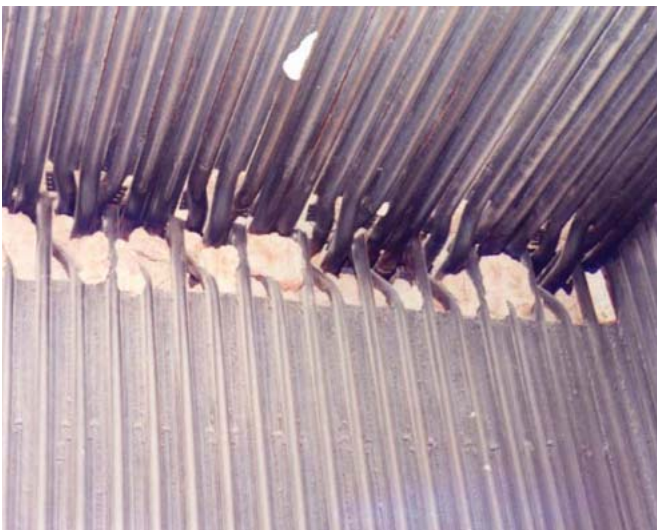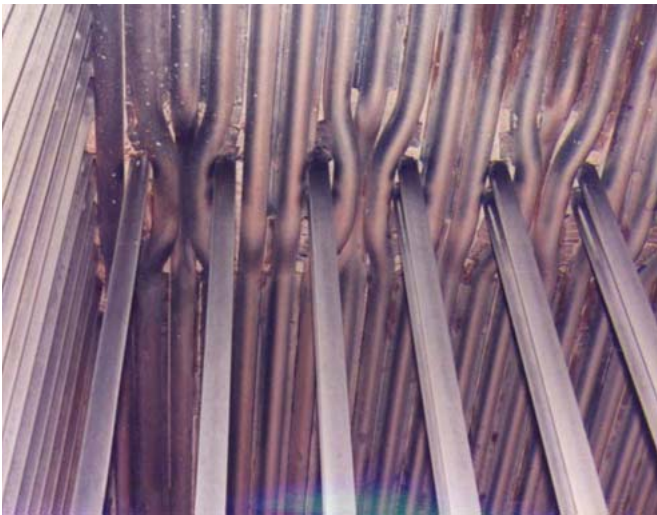
7. Roof/penthouse tube penetration. The level of air in-leakage was approximately 2% of the level of total combustion air. Shown are typical "air washing" of the tube penetrations (top) and air infiltration at the juncture of the roof and rear convection wall tubes (bottom). *Courtesy: Storm Technologies Inc.*

that in most subcritical steam cycles, de-superheating spray water comes directly from the boiler feedpump and bypasses the top feedwater heater(s), the top heater, and the high-pressure turbine.

High FEGTs will almost certainly be the result if the atmosphere in the upper furnace is reducing. When this is the case, often the softening temperature and sometimes the fluid temperature of the coal ash is approached or exceeded. Due to the high FEGT, and closer tube spacing of the boiler convection passes, slagging and fouling are likely to increase. Sootblowing more frequently may mitigate the problem, but doing so incurs two costs: the expense of using steam or compressed air to clean boiler surfaces and an increase in draft losses due to popcorn ash carryover into the baskets of the selective catalytic reduction system and/or air heater.

Regarding the latter, recall that increased draft losses contribute to higher auxiliary power consumption by the air heater. They also increase air in-leakage by increasing the pressure differential between outside air and air in the duct. Increased draft losses can even worsen furnace conditions by taxing the capacity of the induced-draft fan.

Finally, consider the air in-leakage that bypasses the airside of the combustion air heater. Whether it is backpass leakage or air that leaks into the lower boiler ash hopper due to a damaged water seal, this air does not flow through the air path of the air heater and therefore contributes to a higher FEGT. High FEGTs and the masking of high temperatures by the dilution of air in-leakage also can create significant increases in dry-gas loss that an ASME PTC-4.1 or PTC-4.0 performance test can quantify.

Heat rate on the industry's radar

The Electric Power Research Institute's (EPRI's) Heat Rate and Cost Optimization program coordinates much of EPRI's efforts to improve the performance of coal-fired power plants. Specific examples include implementing intelligent sootblowing techniques; using optimization tools to identify the tradeoffs between NO_x emissions and heat rate; and demonstrating on-line instruments that use continuous emissions monitoring to calculate coal feed rates, heating values, and heat rates in real time.

The EPRI group also hosts meetings like this past January's Heat Rate Improvement Conference in Cedar Rapids, Iowa. There, utility experts, suppliers, consultants, and academics came together to share their experiences and ideas for improving the performance of the U.S. coal-fired fleet.

Presentations at the conference covered the fundamentals of combustion, cycle isolation, turbine testing, feedwater heater testing and repairs, and intelligent sootblowing. A number of case studies also were presented. Participants outlined potential opportunities for heat rate improvement by applying diagnostic testing to feedwater heaters and condensers and by using cycle isolation to investigate turbine performance. The techniques involved ranged from the tried and true to the latest in on-line monitoring, advanced sootblowing, and fuel and air balancing in the boiler.

The consensus of conference attendees mirrored the main conclusions of this article. In a nutshell: The path to lowering the heat rate of the typical pulverized coal-fired utility power plant—and raising its profitability—runs through the plant's O&M department.

8. Penthouse ash accumulation accompanies air leakage. The before photo (top) shows buildup of ash; the after photo (bottom) shows the same area after repairs were begun. *Courtesy: Storm Technologies Inc.*

Test, and inspect too

The path to a "tight" gas path begins with periodic testing to identify and quantify specific opportunities for heat-rate improvement. Here are specs to meet and steps to take to optimize pulverized coal combustion:

- The furnace exit must be oxidizing, preferably at 3%.
- Fuel lines to each burner should be no more than 2% out of balance, as measured by a "clean air" test.
- Fuel lines should be no more than 5% out of balance, as measured by a "dirty air" velocity probe.
- Fuel flows should be no more than 10% out of balance.
- Fuel line fineness should be 75% or greater passing a 200-mesh screen. The difference in the fineness of 50-mesh particles should be less than 0.2%.
- Primary airflow and overfire airflow should be controlled to within 3% accuracy or better.
- Primary air/fuel ratio should be accurately controlled when above minimum.
- The minimum velocity within fuel lines should be 3,300 ft/min.
- Mechanical tolerances of burners and dampers should be ±0.25 inch or better.
- The flows of secondary air to burners should differ by no more than 5% to 10%.
- The feeds of fuel to pulverizers should be smooth during load changes and controlled as accurately as possible—preferably by load cell–equipped gravimetric feeders.
- The quality and size of the fuel feed particles should be consistent. Preferably, the size of the largest particle should be 0.75 inches.

9. Air leaks. Leaks inside the nose arch (top) and casing (bottom) within the "dead air space" of a 1950s-vintage coal-fired boiler. *Courtesy: Storm Technologies Inc.*

Tests to improve heat rate

Boiler air leakage tests between the furnace and the stack. They can quantify the levels of primary airflow and leakage in the boiler setting pulverizer as well as the amount of leakage in the air heater and ductwork leakage.

Performance testing of the pulverizer's primary airflow, with an eye toward fuel line balancing. Higher primary airflows, which are very common in older coal-fired plants, often produce higher-than-optimal tempering airflow. Fuel rejects due to non-optimal mechanical settings (for example, out-of-whack grinding element clearances or pressures, pulverizer throats that are too wide, and/or poor fuel fineness and fuel distribution) also can contribute to high furnace exit gas temperatures. Meanwhile, high gas temperature stratifications can raise the temperature of boiler tubes, decreasing their reliability and increasing the potential for slagging, fouling, excessive soot blowing, and higher draft losses. High levels of carbon in bottom ash and flyash are the most obvious consequences of non-optimized pulverizer performance.

Flow verifications of the combustion airflow measuring element, by hand traverses of all ducts, including those for secondary and overfire air.

Representative sampling of the carbon content of flyash and bottom ash.

Verifications of critical fluid temperatures, including those of main steam, reheat steam, superheating steam (before and after the de-superheater), cold reheat, reheat after spray, and feedwater.

See the box for a list of specific tests that have been used to improve the heat rate numbers of large pulverized coal-fired boilers. These tests should be conducted quarterly. This frequency provides ample opportunity to use the results to plan outage corrections, to monitor performance during high load factor periods, and to verify successful maintenance repairs immediately following each outage.

To conclude this crash course, here's a final piece of advice: Try to incorporate the principles of condition-based maintenance into your work orders. For an example of why that's a good idea, consider that the timing of most pulverizer-rebuilding projects is keyed to the pulverizer's total throughput or total hours of operation since the last rebuild. A better way to discern the need for pulverizer maintenance and air flow calibration is periodically testing the unit's flow and fuel fineness and distribution. ∎

*—**Richard F. (Dick) Storm** is president of Storm Technologies Inc. (www.stormeng.com), a consultancy based in Albemarle, N.C. The firm's specialty is optimizing the performance of industrial and utility boilers through testing and measurement and the pursuit of excellence in O&M. Dick Storm can be reached at 704-983-2040.*