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Boiler MACT Compliance

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Boiler MACT Compliance: You Might be Closer Than You Think

Insights learned from working with power utilities and industrial facilities on compliance projects

Introduction

Neundorfer, Inc., Storm Technologies and United Dynamics Corporation are working together to help utilities and industrial companies develop pollution control and energy efficiency strategies. In this paper, we discuss factors in each area of the process that affect the existence, formation or capture of pollutants regulated by the Boiler MACT rules.

These insights touch on many sub-topics, including:

- The concept of control, influence and react as it relates to MACT compliance.
- How fuel preparation and combustion impact MACT pollutants.
- How issues with heat transfer affect the formation of MACT pollutants in the boiler.
- Air in-leakage and how this impacts MACT pollutants.
- Effective ways of capturing MACT pollutants on the back end of the plant.

Control, Influence, React

Our objective in this paper is first to touch on what we can control, what we can influence, and what we need to react to in relation to pollutants regulated by MACT. Envision these as a series of spheres; what we control is very small, in the center. What we can influence, but not control, is a larger sphere. What we have to react to, but cannot control or influence, is much larger.

When creating strategies, such as for compliance, we are faced with this scenario and must understand what is within our control, what we influence, and what we are reacting to. We will start by sharing some of the things learned so far from working with customers on MACT compliance projects.

Figure 1: Spheres of Control, Influence and React

What We Have Learned About MACT

We are currently involved in a few MACT compliance planning efforts. One of the initial steps in the planning process was to design and execute a baseline testing program that produces the information necessary for making future decisions. In reviewing some of the initial baseline results, most of the boilers were meeting or within reach of compliance on many of the MACT pollutants.

Figure 2 displays a summary of current MACT pollutant emissions (carbon monoxide, dioxins/furans, hydrochloric acid, mercury and particulate) from 11 of the boilers we are currently evaluating. The colors indicate each boiler's level of compliance with each pollutant. Green means that they are well within compliance. Yellow indicates that the emissions levels are below MACT limits with little margin. Orange indicates that current emissions levels exceed MACT limits.

		Emissions Testing Results						Particulates		
Boiler	Boiler Steam Flow (Mpph)	SO2 (ppmvd @ 3% O2)	NOx (ppmvd @ 3% O2)	CO (ppmvd @ 3% O2)	Dioxin/ Furan (ng/dscm @ 7% O2)	HCl (lbs/ MMBtu)	Mercury (lbs/ MMBtu)	ESP Inlet (lbs/ MMBtu)	ESP Outlet (lbs/ MMBtu)	Removal (%)
Boiler 1	98.99	239.4	179.5	5600.0	0.1044	0.0003	2.93E-06	2.13	0.0126	99.40
Boiler 2	96.57	263.2	212.7	1300.0	0.0267	0.0017	4.04E-06	2.26	0.0030	99.80
Boiler 3	98.49	270.4	204.7	1067.0	0.0300	0.0018	4.58E-06	2.67	0.0069	99.80
Boiler 4	158.74	167.4	239.8	77.4	0.0013	0.0030	1.22E-06	3.25	0.0074	99.77
Boiler 5	156.93	189.1	297.9	91.8	0.0011	0.0015	1.13E-06	3.27	0.0024	99.93
Boiler 6	242.28	208.8	282.8	2957.7	0.0164	0.0013	5.13E-06	4.45	0.0360	99.20
Boiler 7	241.57	234.8	286.7	2262.5	0.0121	0.0006	4.09E-06	3.82	0.0330	99.10
Boiler 8	245.81	236.7	290.0	1396.1	0.0646	0.0012	3.98E-06	1.13	0.0700	93.80
Boiler 9	102.67	248.8	430.4	334.8	0.0057	0.0023	2.29E-06	3.74	0.0149	99.50
Boiler 10	101.86	314.5	379.5	199.8	0.0045	0.0022	2.89E-06	3.89	0.0303	99.10
Boiler 11	102.76	206.4	341.0	430.7	0.0036	0.0011	4.11E-06	6.36	0.0182	99.70

Figure 2: MACT Case Study

This group of boilers has a serious problem with CO and dioxins and furans. About half of the boilers are near or above MACT mercury limits. The same can be said for particulates.

Note that boilers 4 and 5 easily passed all MACT emissions tests. We believe that some of the answers for improving the other boilers can be extracted from further analysis of #4 and #5; it seems likely that their MACT pollutant levels are partly a result of superior combustion and optimal flue gas temperatures.

For the other nine boilers, we would first recommend a program to improve combustion. The goal of this program is to reduce CO and D&F formation, and also improve particulate and mercury emissions by reducing treated gas volume.

If mercury is still an issue after these front-end improvements are made, it might be necessary to add some sorbent and make sure the precipitator is operationally good. Likely, most of these boilers can be brought into compliance without spending a dime on particulate or mercury removal equipment.

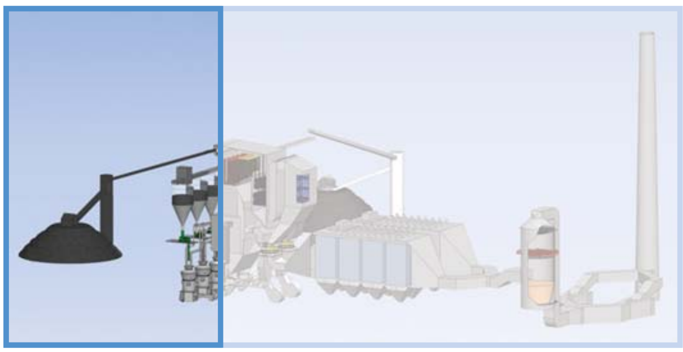
The next step might be to look into any other process improvements that could reduce treated gas volume. These include improving thermal efficiency, reducing air in-leakage, and reducing exit temperatures to a reasonable level. In extreme cases, as much as 1,000 BTUs per kilowatt hour heat rate can be gained through such a program. This translates to 20-30 percent reduction in particulate emissions. After completing this program, we might recommend re-testing the MACT pollutants.

Before considering any add-on controls, boiler operators should first invest in a baseline testing and optimization program. Baseline testing is more than just a stack test. It is an integrated effort that seeks to understand the whole system and the stack test is just part of it. The goal is to combine combustion systems testing (primary/secondary/over-fire air measurements, O_2 rise from furnace to the stack, etc.) with reliability and environmental considerations. Thorough testing and optimization for a typical 500 megawatt boiler costs around $200,000. Ideally, such testing should be performed before and after each major outage so maintenance people have data they need to make cost-effective, meaningful and results-oriented corrections or adjustments.

Such a program requires looking at the right data and understanding how it is all interconnected. We have been involved with many programs where the user thinks they have the right data, but it does not correlate with anything and we have to start over. Bad data usually leads to bad decisions.

Fuel Preparation and Combustion

It is also necessary to understand how each of the MACT pollutants is created, influenced or controlled in the fuel preparation part of the system and during combustion.



First, consider particulate matter. If coal is not burned completely, carbon becomes part of the particulate matter that has to be treated. That is why coal fly ash is sometimes called "refuse" by boiler efficiency engineers. The refuse is both ash and unburned carbon. Coal fineness has a huge impact on particulate matter quantity and properties. High levels of carbon in ash causes problems for electrostatic precipitators.

Poor fuel fineness has at least three adverse effects on combustion. First, it affects carbon in ash. Secondly, it impacts flame carryover into the convection pass of the boiler, which can result in superheater slagging and fouling, draft losses, and other problems. Finally, because of delayed combustion and resulting flame quenching, poor fuel fineness causes carbon monoxide production. CO can be minimized by optimum particle size and fuel distribution. These are all fundamentals of good combustion.

One characteristic, like fuel fineness, can have multiple effects on the process, which then can have multiple effects on emissions.

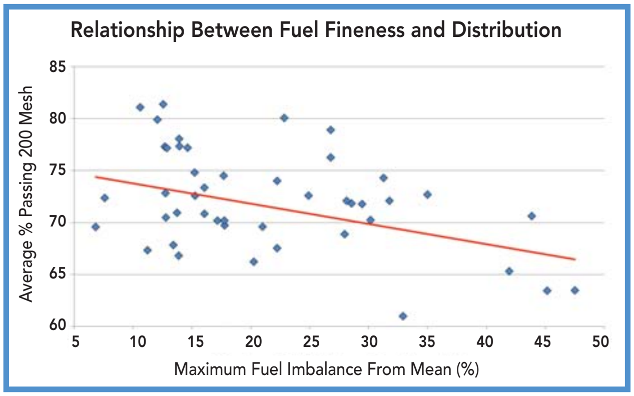


Figure 3. How Fineness Affects Fuel Distribution

Best Practices for Optimizing Combustion

Optimizing inputs to the furnace is important for five reasons.

First, most plants do not have good fineness on a day-to-day basis. When a push comes to a shove, operations will generally sacrifice fineness for pulverizer throughput. More fuel into the furnace can create more steam production to produce more megawatts even if it is done inefficiently. Often, the plant focus is on power production not excellence in combustion.

Second, when fineness deteriorates, so does fuel balance. Conversely, when fuel fineness is very good, so usually is fuel distribution. Good fineness by our definition is about 75 percent or better passing a 200 mesh screen and only one or two tenths of a percent on a 50 mesh screen. So, when fineness is very good, usually so is fuel distribution balanced to the individual burners. The idea here is to treat each burner like a cylinder in an internal combustion engine. We like to have in the range of plus or minus 10 percent to each burner. Poor fineness can result in fuel distributions of ±25 percent and even worse.

Third, the furnace residence time for complete combustion is only one or two seconds, at most. We have seen some boilers were residence time is as low as a quarter second from the top burners to the superheater. From this, it is easy to understand the importance of getting the inputs to the burner belt optimized.

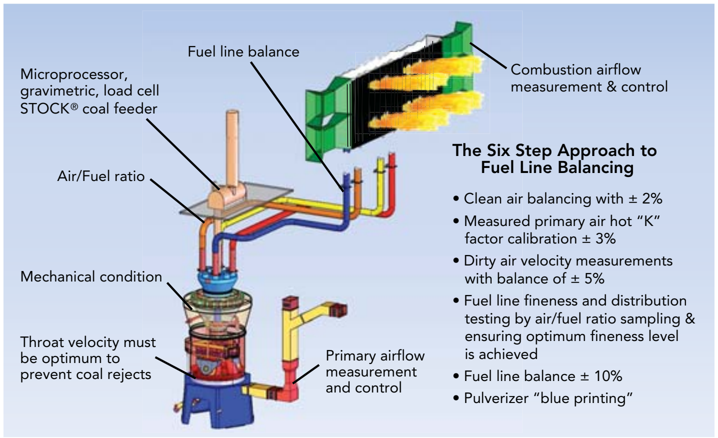


Figure 4: Solid Fuel Injection System

Fourth, CO must be combusted in the furnace. Achieving low CO at the furnace exit is the start of reducing the formation of dioxins and furans. Excellence in furnace combustion can be measured by using a water cooled HVT probe and extracting furnace flue gases to run through an analyzer. If the furnace is oxidizing, say, three percent excess oxygen at all points, and the fineness is good, then chances are the CO levels will be very low.

Finally, temperature is a key factor of efficient combustion impacted by optimized inputs. In a non-optimized furnace, we have seen gas temperatures at the superheater being 1,000 degrees higher than design—hot enough to melt platinum-rhodium and stainless steel radiation shields. Platinum melts around 3,200°. If flames are being quenched in the superheater, CO will be off-scale for many of our analyzers. Getting the inputs right is a huge opportunity on almost all the boilers we have been involved with.

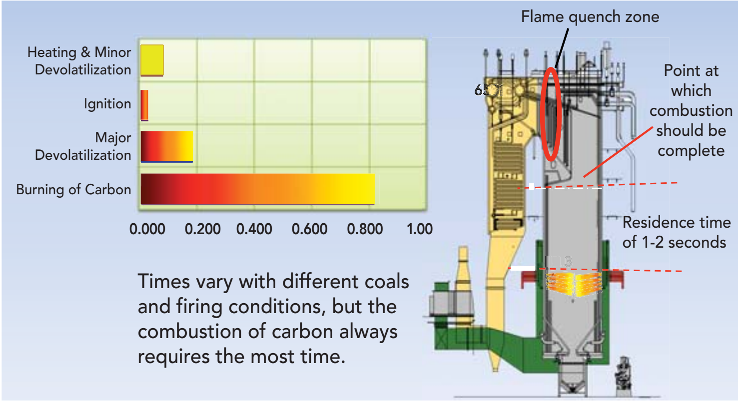


Figure 5: Combusting Coal - Time Requirements

At Storm, based on our long experience in this area, we have developed our pretty well-known **13 Essentials of Optimum Combustion.** These are a great start.

1. Furnace exit must be oxidizing, preferably 3%.
2. Fuel lines balanced to each burner by "Clean Air"test ± 2% or better.
3. Fuel lines balanced by "Dirty Air" test, using a Dirty Air Velocity Probe, ± 5% or better.
4. Fuel lines balanced in fuel flow to ± 10% or better.
5. Fuel line fineness shall be 75% or more passing a 200 mesh screen. 50 mesh particles shall be less than 0.1%.
6. Primary airflow shall be accurately measured and controlled to ± 3% accuracy.
7. Overfire air shall be accurately measured and controlled to ± 3% accuracy.
8. Primary air/fuel ratio shall be accurately controlled when above the minimum.
9. Fuel line minimum velocities shall be 3,300 fpm.
10. Mechanical tolerances of burners and dampers shall be ± 1/4" or better.
11. Secondary air distribution to burners should be withing ± 5% to ± 10%.
12. Fuel feed to the pulverizers should be smooth during load changes and measured and controlled as accurately as possible. Load cell equipped gravimetric feeders are preferred.
13. Fuel feed quality and size should be consistent. Consistent raw coal sizing of feed to pulverizers is a good start.

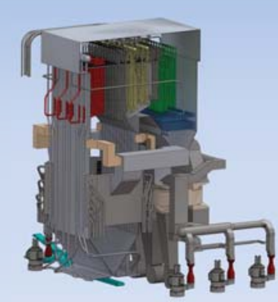
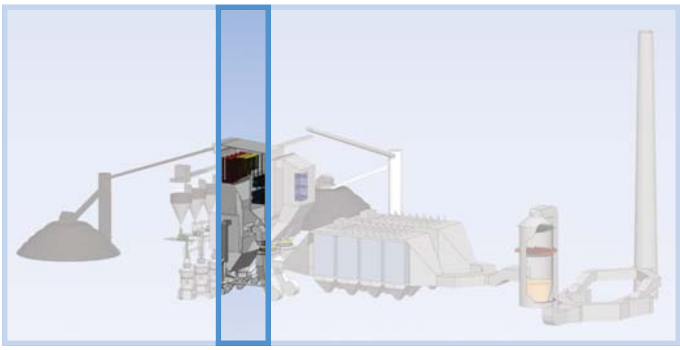


Figure 6: 13 Essentials of Optimum Combustion for Low NO_X Burners

Nine of the 13 essentials are pulverizer, primary air, fuel line and classifier related. Fuel fineness, primary airflow measurement and control, classifier tuning, secondary airflow, and over-fire airflow measurements and control remain vitally important. Proper airflow proportioning during load changes is a particular challenge with swinging loads, such as where intermittent wind mills supply power to the grid.

Heat Transfer

In this section, we consider how slagging, soot blowing and other issues with heat transfer affect the formation of MACT pollutants in the boiler. We also touch on influences that come into play in the boiler, affecting the difficulty of separating these pollutants when reacting to them downstream.



Historically, the boiler reliability group at UDC has not spent much time thinking about environmental compliance issues. It was not until the development of our alliance with Storm and Neundorfer that our eyes were opened to all aspects of plant operation, from the coal pile to the stack outlet. We soon discovered that by understanding the other processes we could significantly improve our own specific scope of concern—"The Pressure Parts."

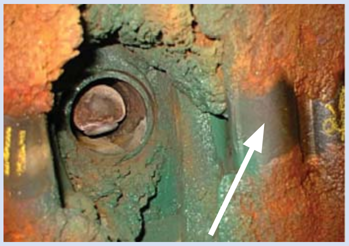
Slagging is a great example of something that ranks near the top of the list when it comes to boiler tube leak preventative maintenance, and which also impacts and is impacted by other processes. Removal of slag is one of UDC's bread-and-butter maintenance programs. We do sandblast cleaning and take extensive tube thickness readings utilizing ultrasonic instruments. Our goal is to eliminate boiler tube leaks. After sandblasting and thickness testing, we replace or repair tubes to restore original minimum wall thickness, and also adjust or repair soot blowing devices. What is typically left out of our equation, though, is a joint effort involving combustion performance and environmental people.

If the combustion inputs are correct, then the formation of slag and ash buildup is reduced, and subsequently the need to spend time removing slag is also reduced. Ultimately, there are multiple benefits achieved by optimizing combustion. In this scenario, our responsibility in the boiler reliability group is to supply meaningful information in the form of quantity and specific locations of ash and slag to the combustion folks so they can take proactive measures that get at the root causes of slagging.

Reducing slag not only helps with the overall tube life and reduction of forced outages caused by its removal, but also helps the distribution of heat evenly across all pressure parts. Slagging causes plugging and poorly distributed heat transfer. Some tubes are much hotter than design and some tubes are much cooler. Failures always occur at the extremes, not the average.

This imbalance creates long-term overheat conditions in portions of a component. However, when we replace pressure parts, it is normal practice to replace all tubes because of economies of scale. Many good tubes are scrapped and a lot of money is wasted by these premature replacements.

What we really want to do is prevent tube failures from happening in the first place, and that requires controlling slagging and the related problems of corrosion. Coal and fuel ash corrosion is temperature-dependent—the right conditions must be present for corrosive chemicals to form. Plugging makes it harder to



PRB-fired boiler waterwall section next to active soot blower. Part of tube (arrow) was cleaned by sandblasting.

Pad-welded tubes (to restore thickness)

Figure 7: Waterwall Sandblasting and Pad Welding

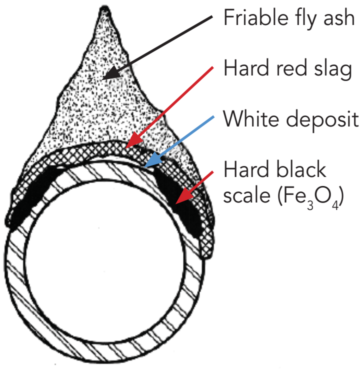


Figure 8: Fuel and Coal Ash Corrosion

predict where this corrosion will appear, and makes managing the problem far more complex and much more expensive than it would be otherwise.

The erosion, or thinning, rate of boiler tubing increases to the square of velocity of the combustion gases. Slagging causes high velocity in some zones and low velocity in others. The result is high thinning in some locales and less thinning in others.

When the boiler is not fouled due to slag and ash it breathes easier or more predictably. Certain locations of the physical design of a boiler were intended to provide changes in pressure drop, resulting in drop out of larger slag and ash. These locations include the hopper bottom, the slag fence at the inlet to the back pass, and a turn and drop out hopper at the economizer outlet. Slagging in many cases reduces the effectiveness of these design elements, causing high erosion rates and higher ash loading of the air heater and environmental collection equipment.

Slagging and plugging cause poor gas distribution, which in turn causes overheating and tubing exfoliation.

Figure 9: Tubing Exfoliation Caused by Slagging/ Plugging and Poor Gas Distribution

Ash plugging restricting gas flow in a horizontal tube component area. Velocity increases along the path of least resistance, where there is less ash (line).

Figure 10: Effect of Ash Plugging on Gas Flow

The point here is that many factors related to efficiency and compliance are inter-related. For example, with better control over chemistry in the firewall area we get a better shot at reducing corrosion and long-term overheat caused by poor gas flow and temperature distribution. This is why our three companies are working together with a holistic approach to optimization and compliance. Our goal is to look beyond the things where normal return on investment is considered. Many benefits come out of the woodwork when we go back to the basics.

1. Slag fence at top of aperture slope causes ash to drop out to bottom of the boiler.
2. Aperture slope returns ash from upper furnace to boiler bottom.
3. Economizer outlet, with 90 degree turn and hopper to collect ash, slag and debris.
4. Hopper bottom directs heavier ash to removal system at bottom of boiler.

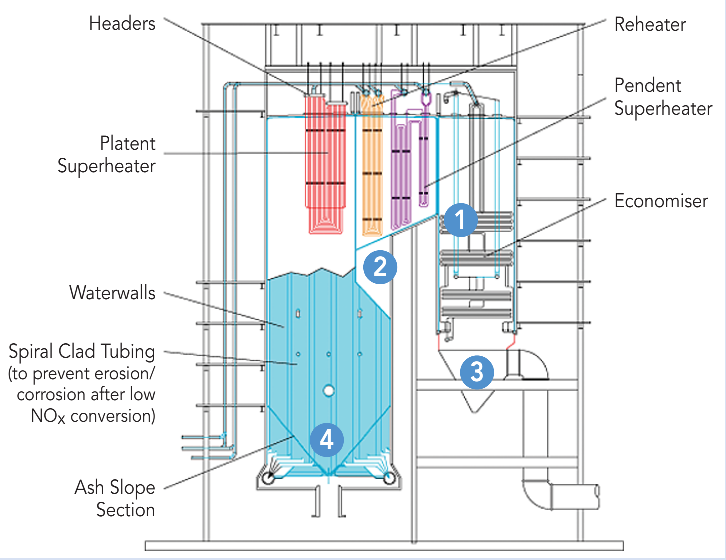
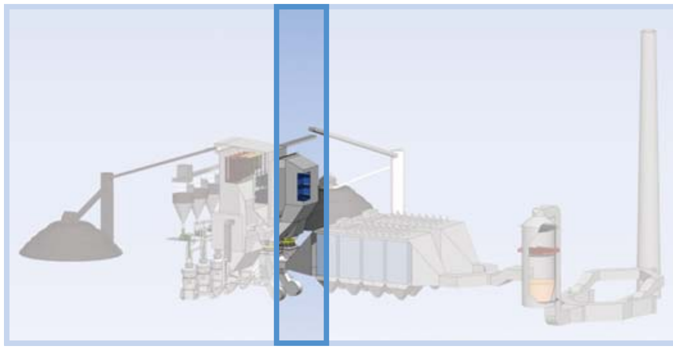


Figure 11: Boiler Design and Slag Removal

Air Heater and Air In-Leakage



Our next topic is tramp air: how an innocent-sounding circumstance such as a little bit of air in-leakage can influence MACT pollutants.

The average age of coal fired boilers in America is nearly 40 years. As boilers age, and joints, weld seams, boiler tube membranes, convection pass tube penetrations and expansion joint cracks open up, the result is excess outside air getting drawn into what we call the boiler setting. This is "tramp air" or "air in-leakage."

Air that leaks into a furnace bottom, ash hopper water-seal, or through a penthouse or convection pass, does nothing for combustion. But this air in-leakage is sensed by the oxygen analyzers at the economizer exit and it is treated by the combustion controls as "combustion air."

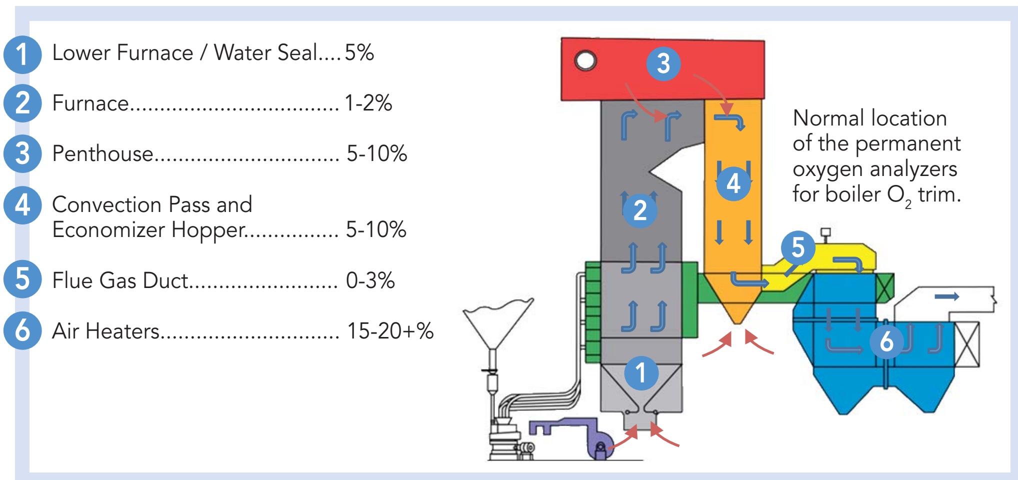


Figure 12: Sources of Air In-Leakage

The excess air that leaks into a suction fired boiler is measured by an oxygen analyzer, just the same as air that was admitted through the windbox. This is an industry-wide problem and is very much under-appreciated. Air in-leakage can result in heat rate penalties on the magnitude of 300 BTUs per kilowatt hour.

This can be quantified by oxygen rise measurements using water cooled HVT probes in the furnace, combined with air heater flue gas inlet and flue gas outlet traverses for a traditional air heater leakage test. Checking the oxygen rise from the furnace to the stack is useful. For a new boiler in operation and at normal excess air levels, the stack excess oxygen may be as low as five percent. Often we test as much as 15 percent excess oxygen. This is a lot of air in-leakage and it is very costly from fan power standpoint alone. It is even worse when the heat losses are calculated.

Air-in leakage at the air heater is another factor. Regenerative Lungstrom air heaters should be capable of nine percent or lower leakage rates. Leakage rates higher than nine percent negatively

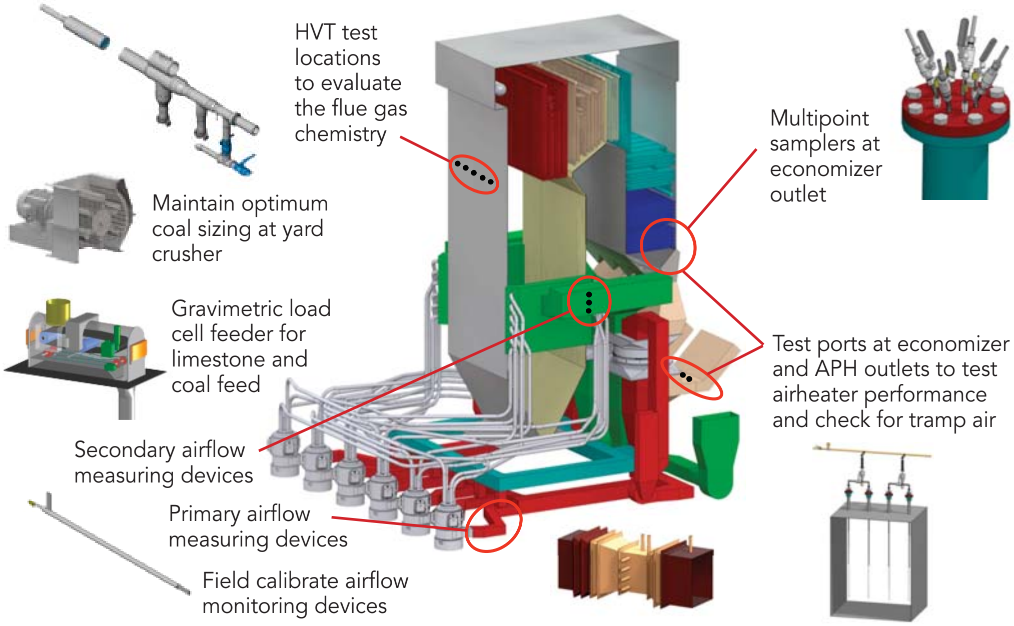


Figure 13: Optimizing Combustion - Ideal Test Locations

affect boiler efficiency in two main ways. First, excessive auxiliary power for fans is required to move the extra airflow. Second, the heat rejection of the flue gas is greater because wasted heat requires operators to maintain the air heater's "cold end temperature."

Greater leakage rates mean more heat needs to be applied to the air entering to keep the cold end baskets above the acid dew-point. When the boiler efficiency is calculated with a "corrected to no-leakage" flue gas exit temperature, the corrected temperature will be significantly higher when the dilution is accounted for. For example, if the corrected-to "No-Leakage" temperature is 35˚ above normal or design, then this represents about one full percentage point in efficiency penalty.

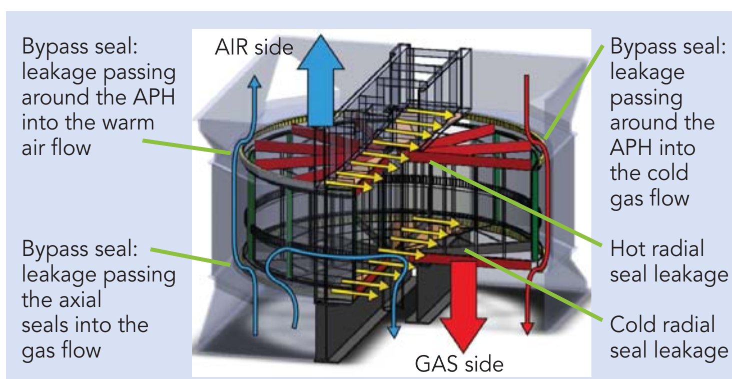


Figure 14: Air In-Leakage and the Airheater.

Air in-leakage is just one part of a holistic focus on compliance. Taking this approach uncovers unseen opportunities, which often translate to basic process adjustments—saving lots of money on downstream equipment investments.

We have seen people spend hundreds of millions of dollars for scrubbers and SCRs and back-end equipment, and walk right past expansion joints, casing tears on the furnace, pulverizer re-builds, fuel fineness analysis, and tramp air in-leakage as high as 25 percent. There are a lot of opportunities being missed.

Process Conditions and Emissions

Improving a boiler's thermal efficiency and airheater performance, and reducing air in-leakage, are important aspects of whole-plant optimization and regulatory compliance planning. These factors can contribute significantly to the volume and temperature of flue gas treated by environmental equipment. In this section we discuss in more detail specific process improvements and their effects on emissions.

First, consider thermal efficiency or unit heat rate. The red line in Figure 15 shows a case where the unit heat rate is reduced from 11,500 to 10,500, thereby reducing treated gas volume by 8.7 percent. Correlating the effects of this efficiency improvement to ESP performance, we see that the result is a 26 percent reduction in outlet emissions. (Blue line in Figure 15.)

Next, let us look at air in-leakage. The dark red line in Figure 16 shows a case where reducing the stack O_2 concentration from 7.5 percent to 6 percent reduces the treated gas volume by 9.5 percent. This can produce a 22 percent reduction in outlet emissions. (Orange line in Figure 16.)

Finally, let us take flue gas temperature into account. The red line in Figure 17 shows a case where the flue gas temperature is reduced from 350˚ to 280˚, and the gas volume is reduced by about 8.6 percent. In this case, since flue gas temperature is also critical to ash resistivity, the ESP performance is improved through two methods. The result is that the outlet emissions are reduced by over 36 percent. (Green line in Figure 17.) It is also important to note that any reduction in gas volume should also reduce the quantity of sorbent feed-rates.

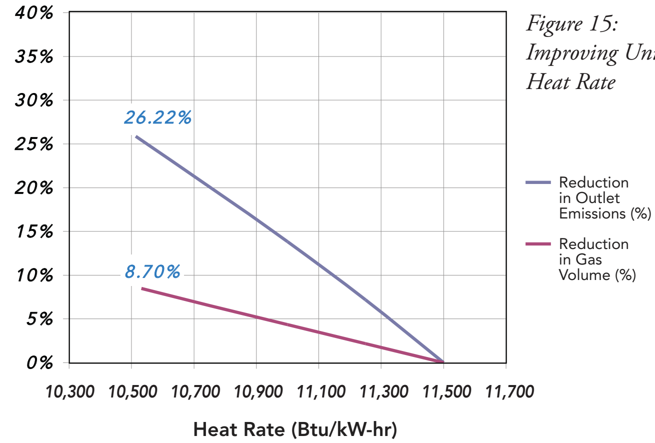


Figure 15: Improving Unit Heat Rate

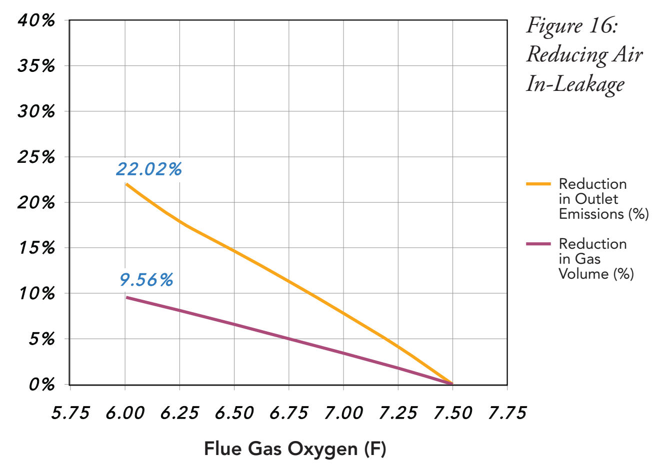


Figure 16: Reducing Air In-Leakage

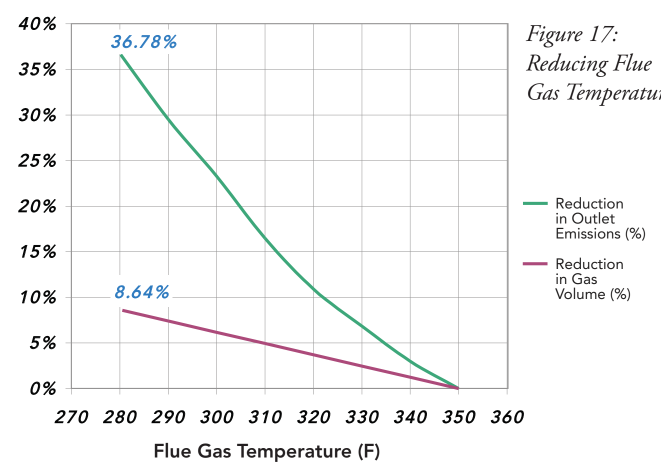
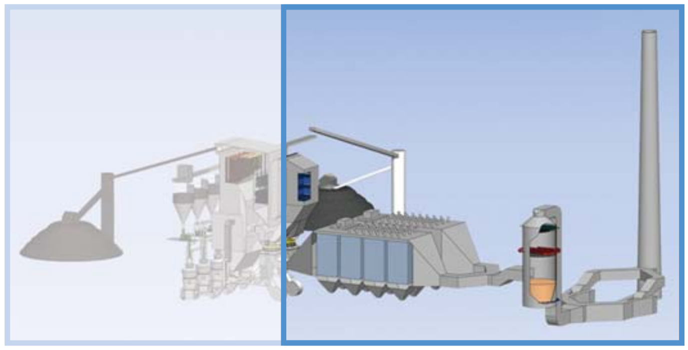


Figure 17: Reducing Flue Gas Temperature

Pollutant Capture



Finally, we move downstream to the back end of the plant to look at effective ways of reacting to particulate matter, mercury, D&Fs, CO and HCl to prevent these pollutants from exiting the stack.

In this section, we look at a case study that illustrates what can happen on the back end and what can be done to respond to all the factors discussed so far. Figure 18 displays the current particulate emissions and various improvement options for each of the boilers discussed in the **What We've Learned About MACT** section of this paper (see page 2.)

	Predicted Mass Emissions Based on Various Modifications							
Boiler	Current Emissions (lbs/MMBtu)	Flow Improvement A (lbs/MMBtu)	Flow Improvement B (lbs/MMBtu)	Reduce Inlet Temp to 350F (lbs/ MMBtu)	Rebuild ESP (lbs/ MMBtu)	Optimize Power Supplies (lbs/MMBtu)	Flow Improvement B and Power Supply Optimization (lbs/MMBtu)	Rebuild ESP and Add 3rd Collection Field (lbs/MMBtu)
Boiler 1	0.01260	0.00886	0.00718	0.00585	0.00433	0.00946	0.00515	
Boiler 2	0.00300	0.00195	0.00149	0.00139	0.00122	0.00217	0.00096	
Boiler 3	0.00690	0.00451	0.00345	0.00315	0.00136	0.00529	0.00250	
Boiler 4	0.00740	0.00410	0.00278		0.00336			
Boiler 5	0.00240	0.00134	0.00092		0.00103			
Boiler 6	0.03600	0.02712	0.02300	0.01428	0.01133	0.02843	0.01722	
Boiler 7	0.03300	0.02515	0.02144	0.01343	0.00983	0.02697	0.01672	
Boiler 8	0.07000	0.05443	0.04726	0.03847	0.04597	0.05942	0.03913	0.01161
Boiler 9	0.01490	0.01026	0.00818		0.00663	0.01159	0.00590	
Boiler 10	0.03030	0.02336	0.02008		0.00526	0.02322	0.01491	
Boiler 11	0.01820	0.01398	0.01198	0.00684	0.00453	0.01441	0.00898	

Figure 18: Pollutant Capture Case Study

Our approach is to use experience with various equipment designs and process characteristics to suggest cost effective improvements. Then, we use our precipitator performance model to predict the future emission levels that would be achieved with each option.

Some of the options are strictly related to process changes. For example, we know that dioxin and furan levels reduce dramatically if precipitator inlet temperatures are reduced below 350°. This process change will also reduce particulate emissions by reducing treated gas volume and ash resistivity.

In this case, we predict that reducing inlet temperatures would bring all of the boilers into compliance on particulate, except for Boiler 8. Many other possibilities exist for improving precipitator collection efficiency. These include optimizing power supplies, making flow distribution improvements, and upgrading internal components. With this modeling process we can predict which combination of options provides the best value.

Once compliance is reached for particulate emissions, we would recommend re-assessing MACT pollutant emissions. If mercury and/or HCl are still an issue, it is probably time to evaluate various sorbent injection systems.

It is worth noting that very similar fuel sources were utilized for all eleven of the boilers in this case study. As we continue the evaluation process, fuel considerations will be one of the first things to look at. If it is possible to get around some of the mercury emissions by changing fuels, and if doing so does not negatively impact the rest of the process, that is a good choice to make. Part of the holistic approach is taking into account fuel options and how they impact combustion, slagging, boiler performance and ESP performance.

Conclusion

We all know where we want to get to on MACT, but if we do not know where we are starting from, it is difficult to get there. Our goal is to go after the low-hanging fruit: simple things like removing slag and re-establishing gas lanes so the gases can flow through as designed with no restriction, or reducing tramp air in-leakage. Revisiting these factors in the process of inspections, repairs and re-alignment does not require a lot of capital money.

The good news is, by starting with baseline testing and optimizing inputs, you may very well find out that little or no investment is required on the back end as far as new equipment. There is a good chance compliance is within reach simply by optimizing what you already have.

Comments

We invite you to share your thoughts about boiler MACT in general and this guide in particular. Please send comments to Mae Kowalke, **MaeK@neundorfer.com**.

About the Authors

Steve Ostanek, Neundorfer's President, joined the company in 1982 and has contributed to its performance in many ways including customer relations, process and equipment analysis, training, consulting, strategic planning and personnel development. He works with the Neundorfer team and with customers to identify opportunities for increasing energy efficiency and reducing air pollution. Steve holds a Bachelor of Science in international marketing from the University of Akron.

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Richard Storm is CEO and Senior Consultant at Storm Technologies, Inc., and has more than 40 years experience fine-turning coal-fired boilers to achieve lowest possible NO_X, best efficiency and maximum fuel flexibility. He founded Storm Technologies in 1992 to focus on helping improve the efficiency of America's coal utility fleet. Richard has authored dozens of technical papers and presented numerous workshops and seminars. He holds a Power Plant Operation degree from Williamson School of Mechanical Trades and is a member of American Society of Mechanical Engineers, National Society of Professional Engineers, American Coal Council, and ASTM International.

John Cavote, expert boiler inspector and instructor, founded United Dynamics Corporation in 1979. He has performed more than 1,000 inspections of utility boilers in his 35-plus years in the industry. John followed in the footsteps of his grandfather and father, benefiting from generational experience handed down consecutively from father to son. His instruction to thousands has advanced the quality of boiler inspections worldwide. John is the author of more than 10 training manuals and holds licenses and certificates in the repair of pressure parts. He is recognized as one of the world's foremost experts on techniques and methodology for boiler inspection.

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