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Technical Publication

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ABSTRACT

Owners of existing coal-fired power plants today have a very compelling case to consider: the addition of, or conversion to, natural gas firing. Lower natural gas prices and more stringent air emissions regulations, in combination with the ability to burn natural gas with its inherently lower emissions have created an atmosphere that warrants analysis. The owner must consider several factors including gas pipeline availability, cost, permitting, timeline, fuel cost and volatility, fuel equipment, and boiler equipment modifications. This paper will focus specifically on several aspects of the boiler that require analysis when considering a gas conversion, including the boiler thermal performance and required combustion system modifications.

This paper describes the required analysis and potential modifications to the boiler combustion system and pressure parts, as well as the resultant change in boiler performance. The analysis will cover the design aspects from the natural gas supply header through the boiler outlet. Topics include FEGT, radiant superheater absorption, spray attemperation, back pass absorption, and potential pressure part modifications. Wall-fired and T-fired PC boilers as well as stoker fired boiler gas conversions are discussed. Several projects (studies and actual retrofits) from the experience of Riley Power Inc., a Babcock Power Inc. company, are used to illustrate the range of modifications and the steps to a proper up-front evaluation required for fuel conversion planning and analysis.

INTRODUCTION

When evaluating the prospect of converting a coal-fired boiler to natural gas, there are a number of factors that need to be independently evaluated. The combustion system modifications and boiler performance impacts are several important aspects to be considered. The combustion system modifications include the firing configuration, emission requirements, fuel supply, and controls. The key boiler performance impacts include furnace exit gas temperature, radiant superheater absorption, air and flue gas flow rates, heat transfer through sections, boiler efficiency, attemperator flow, and tube metal temperatures. This paper will address these considerations and draw on examples for illustration.

COMBUSTION SYSTEM REQUIREMENTS

Analysis of conversion of the combustion system starts at the current and desired firing configuration. Is the unit wall fired, T-Fired, Turbo fired, or Stoker fired? When settled into a firing configuration, more detailed considerations on the burner design and arrangement must be considered including heat input and number of burners, flame length, system and individual burner turndown, valving arrangement, and emissions requirements. This analysis must then be coupled with the boiler performance impacts discussed later in this paper.

Firing Configuration

Natural gas is a very flexible and consistent fuel that allows for industrial and utility burners to be designed for a wide range of heat inputs, from 25 to 250 MBtu/hr or more. At first glance, it is economically appealing to consider using fewer burners with higher heat input to reduce the unit conversion cost. This approach must be cautious, however, because the burner firing arrangement must be mated with the furnace geometry and boiler design. When considering the number of burners and firing arrangement, the furnace heat flux distribution and burner flame length should be evaluated and optimized

Riley Power Inc. (RPI) was contacted to correct the boiler thermal performance issues of a stoker fired unit that had been retrofitted with burners firing vertically up from the surface of the stoker. In that installation the superheat temperature was significantly higher than the original design. To resolve the issue, the client removed forty percent (40%) of the superheater surface to bring the final steam temperature in line with the original design. This point is brought up to emphasize the need to properly size the burner. In this case, the flame length was not fully considered, and resulted in flames extending into the superheater. The optimum heat flux profile for the boiler considers keeping the flames within the furnace and thus having higher furnace gas temperatures and lower furnace exit gas temperatures.

In addition to flame length, side to side heat flux should also be evaluated. With too few burners across the width of a unit, temperatures can potentially result in localized overheating of the superheater, uneven temperatures across the unit, and in severe cases can cause uneven steam drum water levels. This can be evaluated through knowledge of the burner design, as well as boiler thermal hydraulic modeling. In addition, Computational Fluid Dynamic (CFD) modeling can be a powerful tool to evaluate furnace thermal conditions.¹ Figure 1 shows an example of the CFD modeling results feasibility study that RPI performed on several wall fired boilers located in the Midwestern region of the U.S., each rated at 1,000 kpph main steam flow. CFD modeling was used to analyze the furnace temperature distribution and its impact on boiler thermal performance when switching the fuel from bituminous coal to natural gas. In this case, the predicted furnace exit gas temperature between the boiler thermal hydraulic model and the CFD model closely matched, giving greater confidence in the accuracy of the model and boiler thermal predictions.

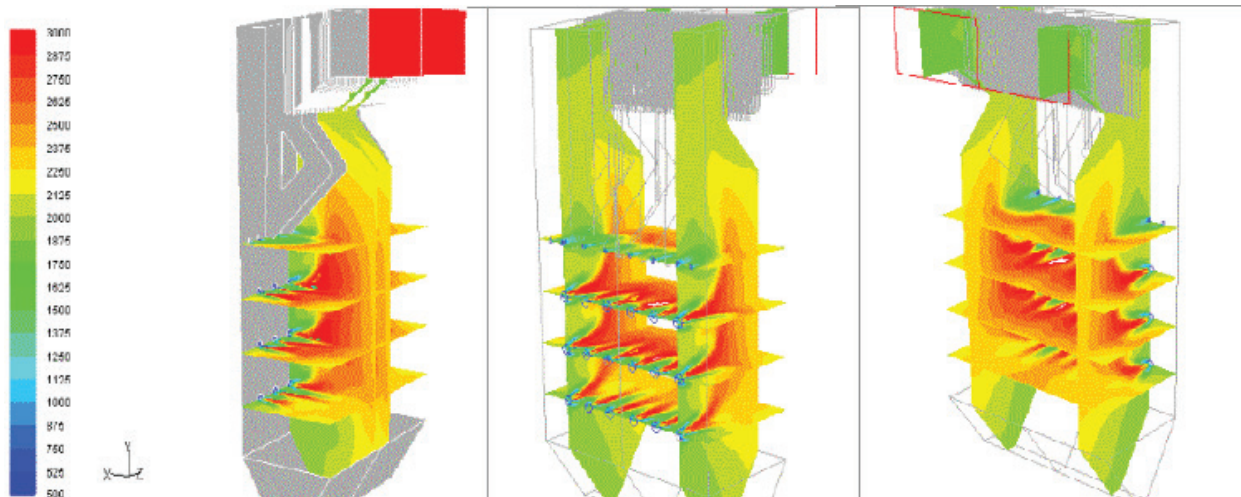


Figure 1 – Calculated Temperature Distributions through Horizontal and Vertical Burner Planes Firing Natural Gas

Emissions Requirements

In today's regulatory environment, emissions play a significant role in boiler owners' decision making, and can be a key driver to convert to natural gas. Not only has natural gas had an attractive price in recent years relative to other fuels, but it also offers the potential for lower stack emissions. Natural gas combustion produces negligible mercury emissions, and has the potential to significantly reduce NO_x as well. Since commercial natural gas contains no sulfur except in the form of mercaptan (the chemical that is added to odorize the gas) there are only trace amounts of SO₂ emissions. Similarly, since natural gas contains no Particulate Matter (PM), the PM emissions are virtually zero other than "background" PM present in the combustion airflow or that which is swept from the boiler.

Regarding NO_x, natural gas contains low fuel-bound nitrogen content and requires lower excess air for combustion than coal. These mechanisms can contribute to low total NO_x emissions that are primarily formed from the thermal reaction between oxygen and nitrogen present in the air at high combustion temperatures. A properly designed combustion system for good NO_x control reduces the peak flame temperature of the primary combustion zone thereby reducing the thermal NO_x formation. State-of-the-art low NO_x gas burners, such as RPI's low NO_x STS[®] gas burner pictured in Figure 2, utilize fuel and air staging to limit the thermal NO_x formation present in highly turbulent and hot gas flames.²

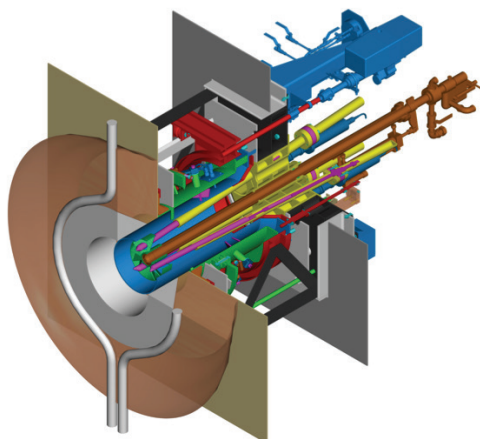


Figure 2 – RPI STS[®] Low NO_x Gas Burner

If low NO_x burners alone are not sufficient to bring the unit into compliance, other combustion system modifications can be made. Additional typical modifications to the combustion system include the addition of OverFire Air (OFA) and Flue Gas Recirculation (FGR).

- Overfire air (OFA)
 - Overfire air ports divert some of the combustion air away from the burners (primary combustion zone) to lower the combustion temperatures and therefore NO_x emissions.
 - Overfire air ports are typically located above the top row of burners.
 - This technology can be used with other NO_x control techniques such as Low NO_x burners and Flue Gas Recirculation.
 - Modifications include the addition of ductwork, air registers, airflow measurement, and boiler wall openings.
 - The furnace performance and geometry must be evaluated to determine if there is sufficient residence time in the furnace for CO burnout with the installation of OFA.
- Flue gas recirculation (FGR)
 - Flue gas from the outlet of the boiler is mixed with the combustion air to the burners.
 - FGR reduces the combustion temperature and lowers the localized O₂ concentration in the primary combustion zone to achieve a reduction in NO_x.
 - Increasing the flue gas flow through the convective pass of the boiler increases heat transfer.
 - Retrofitting the boiler with this system involves new fans, ductwork and dampers, control system, flow measurement and a mixing device.
 - Increase in plant operating cost as a result of the FGR fan motor power consumption.

Computational Fluid Dynamic (CFD) modeling is a valuable tool that can be used to assess the emissions performance and impact of the various combustion system modifications described above, including airflow distribution, furnace temperatures, and CO and Volatile Organic Compounds (VOC) distribution. Figures 3 and 4 depict a single burner CFD Model of the STS[®] Burner and a furnace CFD model of the STS[®] burner coupled with OFA on a 258,000 lb/hr boiler with a down pass furnace design at a West coast paper mill. The single burner model was used to determine the burner settings required for the optimum burner near field flow patterns and the furnace model was used to evaluate the effect of OFA on the furnace VOC, which was particularly important for this application because the furnace combusted several waste fuel gases along with natural gas.

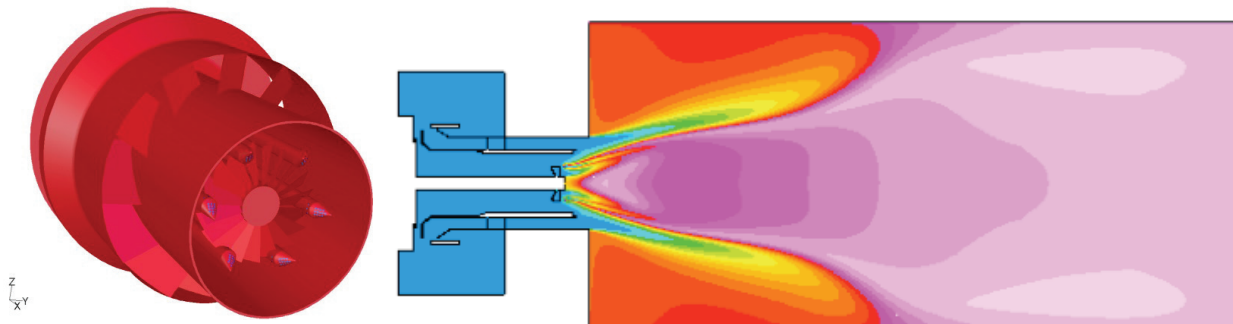


Figure 3 - CFD Model of the RPI STS[®] Low NO_x Gas Burner

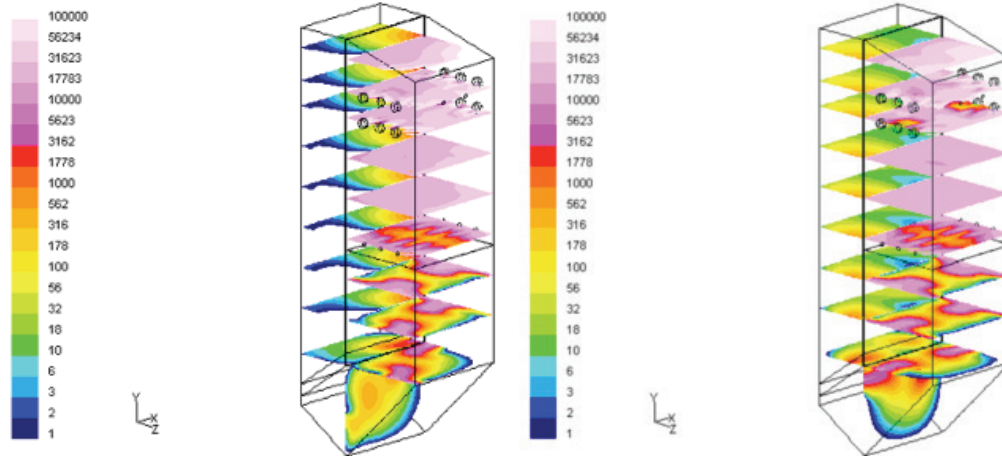


Figure 4 -CFD Furnace Model of RPI STS® Gas Burners & OFA Analyzing VOC Distribution

Beyond combustion system modifications, the use of chemical reagents including Selective Non-Catalytic Reduction (SNCR) or Selective Catalytic Reduction (SCR) can further lower NO_x emissions. The SCR can be designed either as a stand-alone reactor vessel or, for natural gas, part of the ductwork (in-duct SCR). For many industrial applications, combustion system modifications will be generally less expensive in terms of both capital and operating costs, and can be designed to provide sufficient levels of NO_x reduction while firing natural gas such that SCR and SNCR become uneconomical and are not required.

Fuel Supply

An obvious and major component in the evaluation of switching fuels is the supply of natural gas. Without existing gas pipeline access, a plant can face significant costs for gas supply. After the gas supply to the plant has been secured, the plant will need to install the proper piping and valving to allow safe and reliable operation that meets the firing flexibilities required by the boiler. Although valving and burner systems can be designed for lower pressures, it is ideal for the combustion system to have a plant inlet supply of 25 psig or higher. Valve train piping and instrumentation requirements for safe boiler operation are outlined in the latest edition of the National Fire Protection Association (NFPA) boiler and combustion systems hazards code.³

In addition to the NFPA code, an understanding of the desired unit operation needs to be considered when designing the natural gas supply system. Do the burners need to be operated independently, or can they be fired as one? Does the burner have multiple gas manifolds, and do they need to be controlled independently? Is a total unit gas flow control adequate, or is heat input biasing necessary? The system designer should investigate these questions, as there are inherent tradeoffs between flexibility and system cost.

Riley Power recently participated in field testing on a wall fired boiler rated at 1,779,000 lb/hr of main steam flow. The boiler is an opposed fired design with two (2) levels of burners on both the front and rear walls. The natural gas supply system to the boiler utilized a single flow control valve for all the burners. The plant operation wanted the ability to bias heat input in between different levels of burners, but the single control did not allow it. Furthermore, when bringing individual burners in and out of service, the single control valve set up could cause pressure fluctuations among the other burners in service, and required close monitoring by operations. This same drawback of having a

single flow control valve has been observed on other boilers.⁴ As a result of the operations feedback, the plant is undertaking an effort to install a flow control valve at each level of burners to allow for heat input biasing as well as limit the fluctuations when taking burners in and out of service. Thus requires the need to consider the desired boiler operation when designing the gas supply system.

Controls Modifications

A fuel conversion will require an update to the plant’s Burner Management System (BMS), which is the control system that is dedicated to the safe and proper operation of the combustion system. Many of the considerations necessary to design a safe and proper BMS for a variety of boiler types are outlined in the latest edition of the NFPA boiler and combustion systems hazards code.³ Burner Management Systems are generally implemented in two types of platforms. The most common for utilities is in a plant wide Distributive Control System (DCS). In industrial boilers, there is a mix of DCS as well as Programmable Logic Controller (PLC) based systems. When switching from coal to gas, BMS logic must be developed for implementation into the DCS or PLC hardware.

Typically, new scanners or a scanner upgrade will be required when converting from coal to gas. Natural gas flames emit a higher intensity of radiation in the ultraviolet (UV) zone than coal flames and are therefore typically monitored with UV scanners, while coal flames are typically monitored with infrared (IR) scanners. The different flame spectrum wavelength between the two fuels is also attributable to differences in flame emissivity and boiler radiant heat pickup, which is discussed in the boiler performance section below.

BOILER PERFORMANCE

One of the first questions that may come to mind when considering converting a coal-fired boiler to natural gas is, “What happens to the boiler performance when firing natural gas, and does this require any equipment modifications?” This section of the paper discusses various parameters that must be analyzed, and provides performance comparisons for five (5) different industrial boilers that were selected from past coal to gas conversion projects. Table 1 identifies the original performance and general description of each of the five (5) boilers discussed throughout the remaining sections of the paper.

Table 1 – Original Performance of Natural Gas Conversion Boiler Case Studies

Parameter	Boiler 1	Boiler 2	Boiler 3	Boiler 4	Boiler 5
Steam Flow (lb/hr)	150,000	150,000	170,000	325,000	275,000
Steam Temp. (°F)	735	550	760	905	750
Steam Press. (psia)	630	190	490	890	655
Feedwater Temp. (°F)	350	214	360	350	335
Drum Press. (psia)	650	206	-	967	674
Superheat Attenuation	No	No	Yes	Added Later	Yes
Original Fuel	Bituminous Coal	Bituminous Coal	Coal	Bituminous Coal	Bituminous Coal
Firing Arrangement	PC / Wall-Fired	PC / Wall-Fired	Traveling Grate Spreader Stoker	PC / Wall-Fired	PC / Wall-Fired
Superheat	Yes	Yes	Yes	Yes	Yes
Air Heater Type	Ljungstrom	Tubular	Tubular	Ljungstrom	Ljungstrom

Furnace Exit Gas Temperature (FEGT)

Furnace Exit Gas Temperature (FEGT) is the temperature of flue gas leaving the furnace and entering the convective backpass of the boiler. This is an important factor to determine, as it affects many aspects of boiler performance.

It is typical when converting to natural gas from coal firing for the FEGT to increase. The reason this occurs is because the emissivity of the flame from natural gas firing is lower than that for coal. Therefore furnace water wall absorption is typically lower with natural gas firing. The heat from combustion that is not absorbed by the furnace water walls produces a higher FEGT entering the backpass.

The FEGT for Boilers 1-5, for coal and natural gas firing is displayed in Figure 5. The results demonstrate that there is a trend for the FEGT to increase when switching from coal firing to natural gas. Note that in the case of Boiler 2, there was a slight decrease in the FEGT when firing natural gas. The FEGT for coal firing represents the original predicted performance. Recent coal-fired FEGT data didn't exist because the plant has been firing natural gas for a number of years. The noted decrease in FEGT is due to the fact that the original coal can be classified as a high fouling coal. A high fouling coal will tend to have a high FEGT. The fouling of the furnace walls insulates them reducing the amount of heat that can be absorbed. The FEGT resulting from firing a high fouling coal often exceeds the FEGT that would be produced firing natural gas. However, in general, FEGT is more likely to increase with natural gas firing when switching from low and medium fouling coals.

As previously stated it is a very important to understand how FEGT changes when switching from coal to natural gas firing. An increase in FEGT will affect final steam temperatures, requiring greater

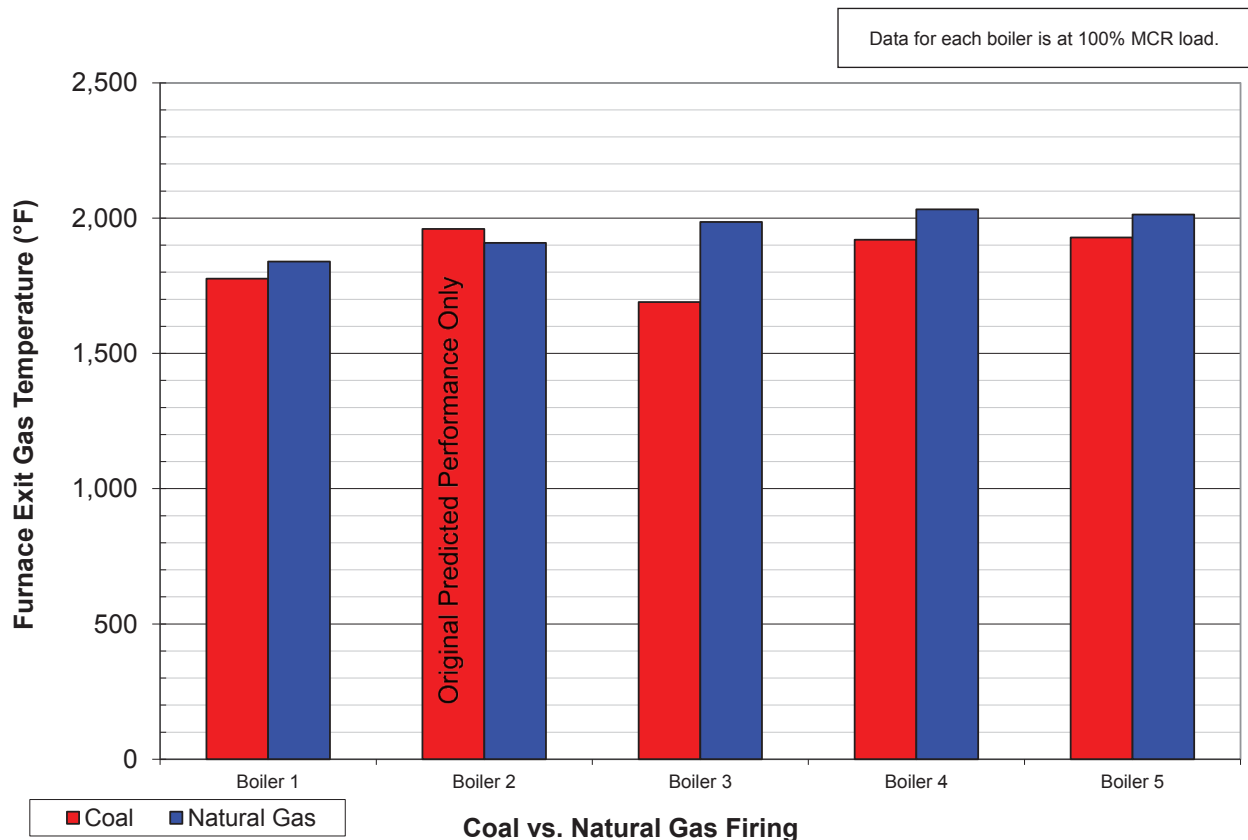


Figure 5 – FEGT for Coal vs. Natural Gas Firing

attenuator flowrates, or other means of steam temperature control. If an increase in steam temperature is acceptable from a performance standpoint, it would also warrant a review of the tube metal temperatures to ensure allowable stress values and material temperature limits are not exceeded. In some cases, pressure part modifications may be required.

Radiant Superheater Absorption

Radiant superheater absorption is another important parameter that should be addressed. Although most industrial boilers don't utilize a radiant superheater section, (Boilers 1-5 don't have a radiant superheater) it is still important to understand how this section may be affected.

Radiant superheater absorption typically decreases when switching from coal to natural gas firing. The reasoning for such is due to the same principals resulting in changes to FEGT. The flame emissivity for natural gas is less than that of coal. Since the primary mode of heat transfer for all surfaces within the furnace is by radiation, the radiant superheater therefore is unable to absorb as much heat when firing natural gas.

A reduction in radiant superheater absorption will mean that final steam temperature may not be achievable. However, this is often offset by greater heat transfer in the convective pass sections caused by the increase in FEGT.

Combustion Air and Flue Gas Flowrates

Differences in combustion air and flue gas flowrates should be evaluated when switching from coal to natural gas firing. Table 2 provides a summary of the fuel, air, and flue gas flowrates, as well as fuel Higher Heating Value (HHV), dry air requirements, and excess air for the five (5) boiler case studies.

It should be observed that natural gas as a fuel has a much higher BTU content than coal when compared on a weight basis. This means less fuel is required. However it also means that there is a greater dry air requirement per pound of fuel for stoichiometric conditions.

Typical coal fired applications operate with approximately 20% excess air. When firing natural gas, excess air of 7-12% is a good range for proper combustion and low emissions.

(Note: Changes in boiler efficiency due to fuel switching will also have impact on fuel flow, and therefore the combustion air and flue gas flowrates. Boiler efficiency shall be discussed later in this paper.)

Table 2 – Fuel, Air, and Flue Gas Data for Natural Gas Conversion Boiler Case Studies

Parameter	Units	Boiler 1		Boiler 2		Boiler 3	
		Coal	Natural Gas	Coal	NG	Coal	NG
HHV	Btu/lb	12,003	23,135	12,300	21,457	11,617	22,250
Fuel Flow	lb/hr	15,517	8,512	15,512	9,300	17,493	9,682
Dry Air Req'd Per Lb Fuel	lb/lb	10.5	18.0	10.7	17.0	12.6	17.4
Combustion Air Flow	lb/hr	164,495	155,262	168,675	160,493	222,950	170,485
Excess Air	%	16.4	10.0	22.0	10.0	47.1	10.0
Flue Gas Flow	lb/hr	178,224	163,774	182,227	169,793	239,162	180,167
Parameter	Units	Boiler 4		Boiler 5			
		Coal	NG	Coal	NG		
HHV	Btu/lb	11,700	23,144	12,195	23,175		
Fuel Flow	lb/hr	35,484	18,714	31,833	17,730		
Dry Air Req'd Per Lb Fuel	lb/lb	10.9	20.5	10.7	18.7		
Combustion Air Flow	lb/hr	390,382	388,875	344,521	335,184		
Excess Air	%	25.0	10.0	18.6	11.7		
Flue Gas Flow	lb/hr	420,372	360,698	372,801	352,914		

Figure 6 is a bar graph showing combustion air and flue gas flowrates side by side for the five (5) boiler case studies. In general when switching from coal to natural gas firing, combustion air and flue gas flowrates decrease slightly. Note however the change in air flowrate is not always proportional to the change in flue gas flowrate. In some instances the change in flue gas flowrate can be much greater than the change in air flowrate. This is a result of how the differences in dry air requirements, excess air, and change in boiler efficiency affect the combustion requirements. For example, compare Boilers 3 and 4. There was a very large decrease in combustion air when switching from coal to natural gas for Boiler 3, but only a very small reduction for Boiler 4. In this case the large decrease in excess air for Boiler 3 was the governing factor causing the large reduction in combustion airflow.

A decrease in combustion air and flue gas flowrate is good from the perspective of fan performance, as the duty requirements will decrease slightly.

A decrease in the flue gas flowrate however will have an offset effect to the total amount of heat available to the convective backpass. As discussed earlier, the increase in FEGT that is typical with a coal to natural gas conversion adds heat to the backpass circuit. Decreases in flue gas flowrate will decrease the heat available to the backpass circuit.

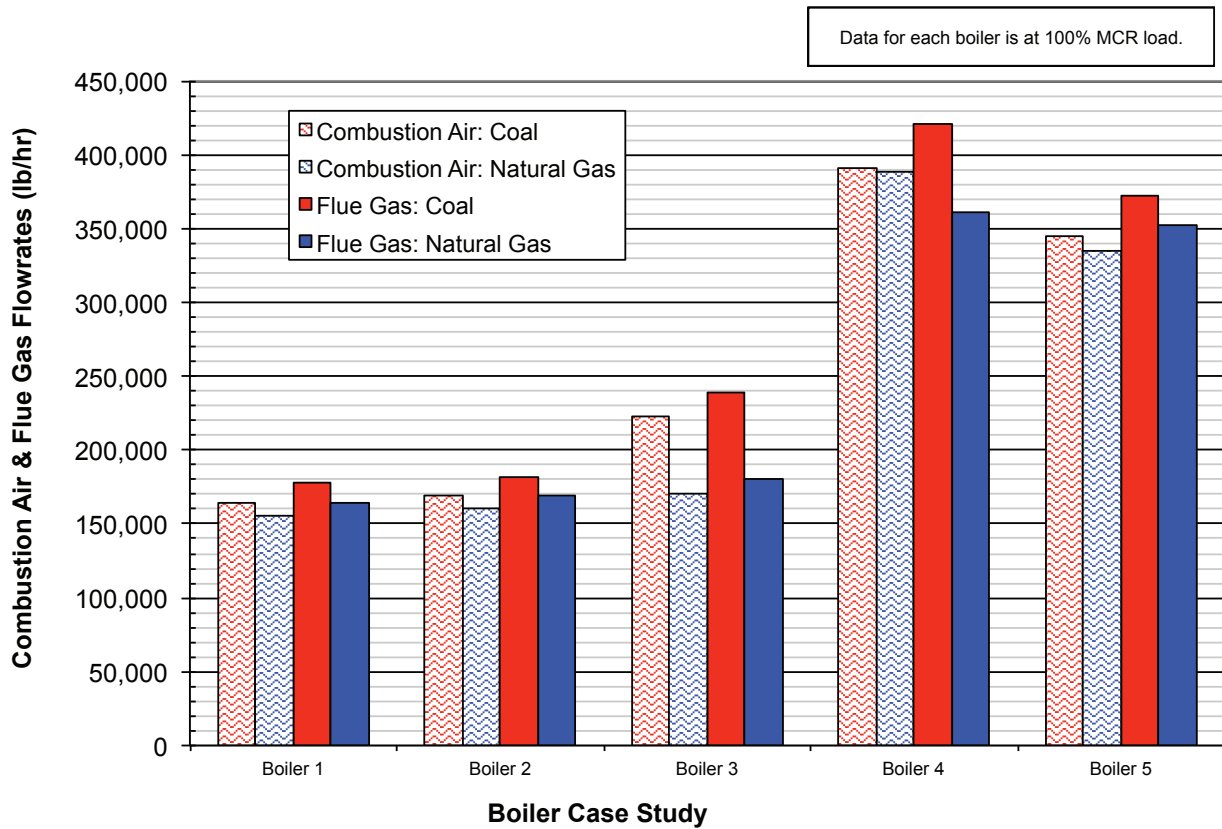


Figure 6 – Combustion Air & Flue Gas Flowrates for Coal vs. Natural Gas Firing

Heat Transfer through Sections

The heat transfer profile through the various boiler sections can be impacted when switching to natural gas due to several parameters.

The increase in FEGT when switching to natural gas automatically provides a boost in the heat content of the flue gas entering the convective backpass sections.

A change in the flue gas flowrate entering the backpass due to changes in dry airflow requirements, excess air, and boiler efficiency, will also have an impact on the heat transfer profile. A general decrease in flue gas flowrate will offset the increase in flue gas heat content due to higher FEGT values.

The convective heat transfer sections can also be up to 15% more effective when firing natural gas, than with coal. The reasoning for this is that coal contains ash. Different coals will have varying propensities to foul the heat transfer surfaces with this ash. This reduces the heat transfer in these sections and is the main reason cleaning devices such as sootblowers are used in pulverized coal boilers. Natural gas doesn't contain ash, and does not foul the heat transfer surfaces. Therefore, the surface heat transfer effectiveness increases when firing natural gas, allowing the surfaces to absorb more heat than typical from firing coal.

A side by side comparison of the surface heat transfer profile through Boilers 1, 2, and 4 for both coal and natural gas, is provided in Figure 7, Figure 8, and Figure 9. (Heat transfer data wasn't available for Boiler 3 and 5.) It can be observed from all cases that furnace heat absorption decreased, which is consistent with the principal that the flame emissivity is lower for natural gas firing. The superheater section heat absorption increased in each case which is likely due to the increase in FEGT and surface effectiveness. The boiler bank heat absorption decreased which was likely due to the reduced flue gas flowrates, and increased absorption effectiveness of the upstream superheater. Therefore the resulting flue gas temperature entering the boiler bank was likely lower. The air heater absorption was lower which was due to lower air and flue gas flowrates through the heater, and a lower inlet flue gas temperature due to higher absorption upstream and the reduced flue gas flowrate.

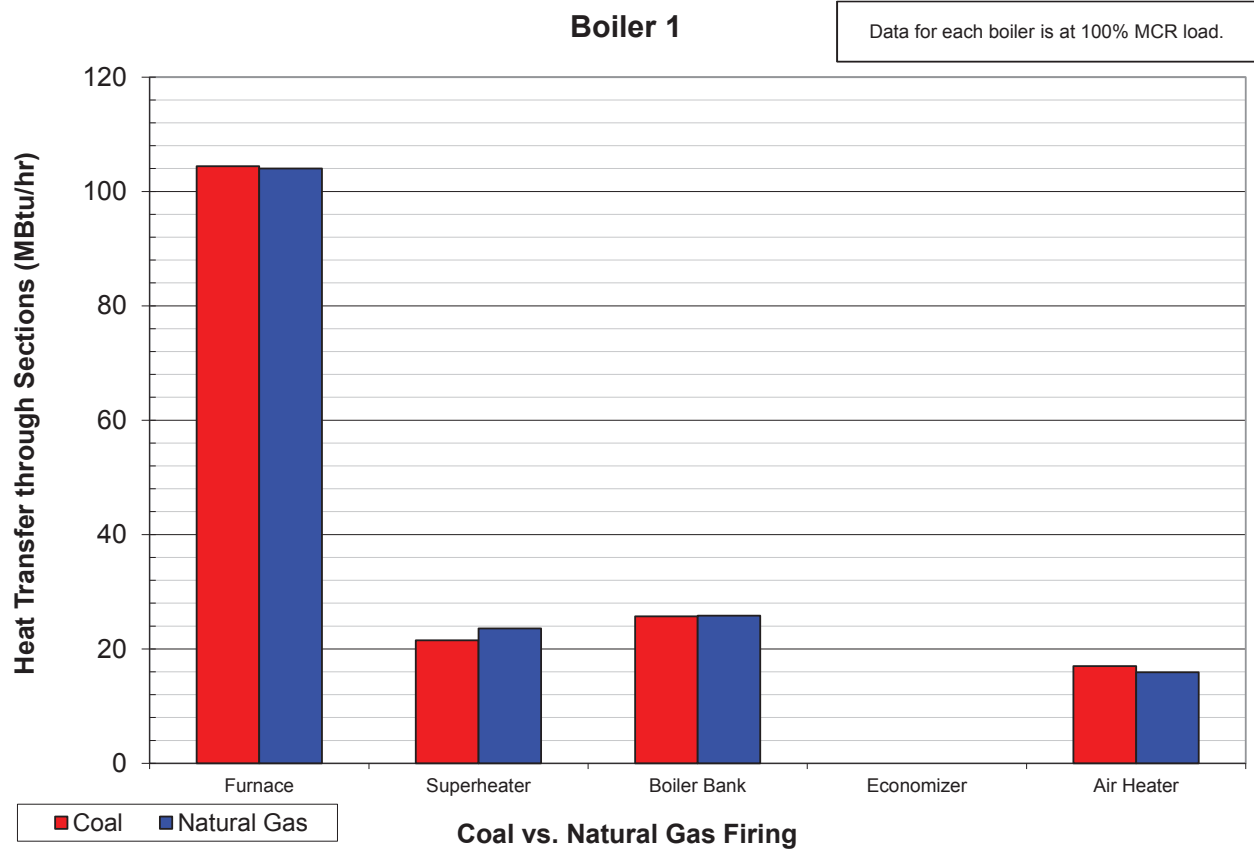


Figure 7 – Surface Heat Transfer Profile for Boiler 1 Coal vs. Natural Gas Firing

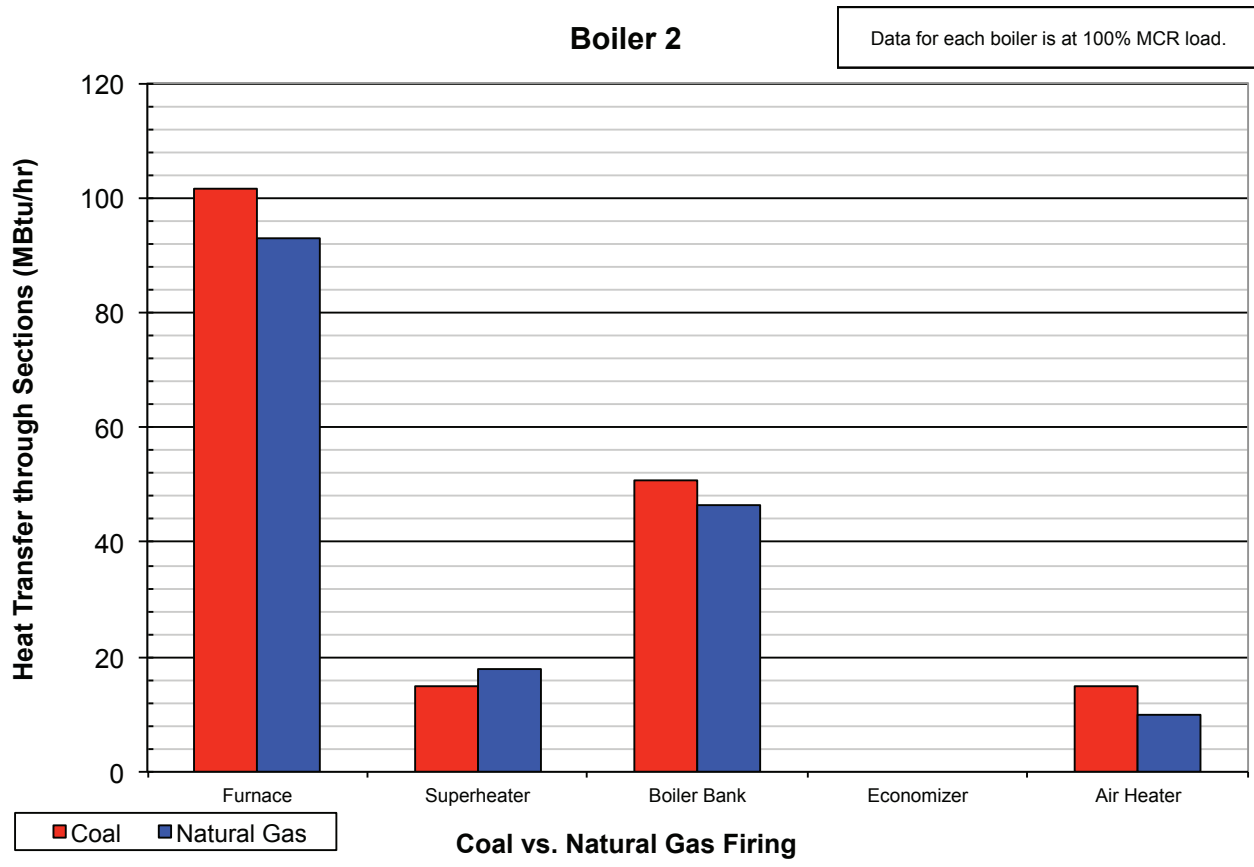


Figure 8 – Surface Heat Transfer Profile for Boiler 2 Coal vs. Natural Gas Firing

Boiler 4

Data for each boiler is at 100% MCR load.

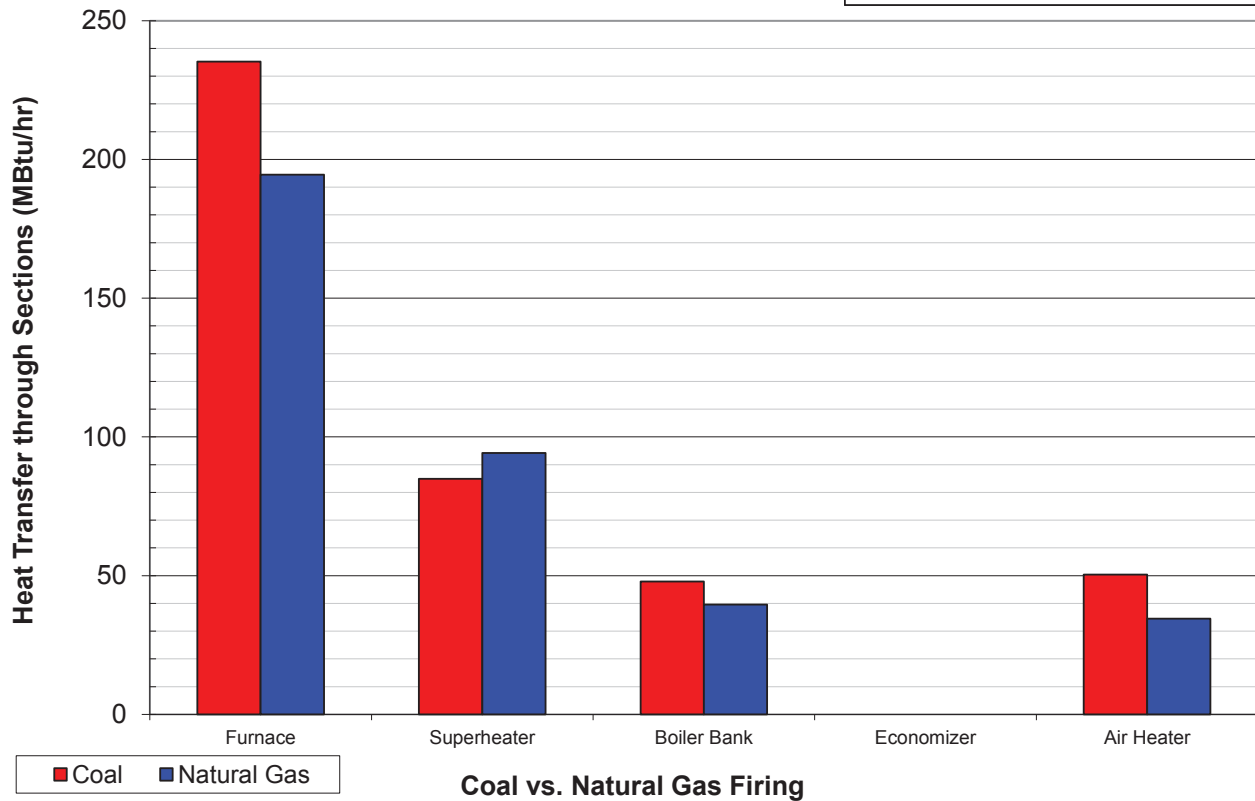


Figure 9 – Surface Heat Transfer Profile for Boiler 4 Coal vs. Natural Gas Firing

Boiler Efficiency

Switching from coal to natural gas firing can significantly impact boiler efficiency. In general, switching to natural gas will result in a decrease of boiler efficiency between 2-5 percentage points. Table 3 provides a boiler efficiency comparison for the five (5) boiler case studies, showing the changes in the major types of losses.

The main reason for the decrease in overall boiler efficiency is due to a large increase in losses due to the moisture generated from the combustion of hydrogen in the natural gas fuel. Natural gas has much greater hydrogen content than coal. The combustion of hydrogen forms water by combining with oxygen. The efficiency loss is a result of evaporating the water produced and raising it up to the adiabatic temperature during the combustion process. This process requires a lot of energy. This energy is no longer available to generate steam within the boiler.

The loss due to the combustion of hydrogen is partially offset by a few other types of losses. Dry flue gas loss typically decreases by a few percentage points. This is due to the lower temperature and quantity of flue gas leaving the air heater. The reasons for this were described in the previous sections.

There is also no fuel moisture loss with natural gas, as the fuel doesn't contain moisture. The loss associated with coal fuel moisture is due to the same principles as loss due to the moisture generated from the combustion of hydrogen.

There is also no unburned carbon loss with natural gas, as the fuel burns completely.

As shown in Table 3 the net change in losses generally increases and this should be considered when performing a switch to natural gas. In some instances however, such as in the case of Boiler 3, efficiency losses may be nearly unchanged. Boiler 3 was unique in that it had quite a large reduction in dry flue gas loss (due to reducing excess air from 47% with coal to 10% with natural gas), and eliminating an unburned carbon loss of 2% when firing coal. (Note the carbon loss of 2% is attributed to the fact that this boiler is a stoker fired boiler, and a 2% carbon loss is typical for this design. In addition it should be noted that 47% excess air was the as-tested measurement, and the reasoning for such magnitude is unknown.)

Table 3 – Boiler Efficiency Data for Natural Gas Conversion Boiler Case Studies

Parameter	Units	Boiler 1		Boiler 2		Boiler 3	
		Coal	Natural Gas	Coal	Natural Gas	Coal	Natural Gas
Dry Flue Gas Loss	%	6.45	5.07	6.16	4.32	7.83	4.73
Moisture in Fuel Loss		0.88	0.00	0.48	0.00	1.38	0.00
Moisture from H2 Comb Loss		4.05	10.78	3.94	10.54	4.18	10.68
Air Moisture Loss		0.15	0.13	0.15	0.11	0.19	0.12
Unburned Carbon Loss		0.85	0.00	1.10	0.00	2.00	0.00
Radiation Loss		0.40	0.40	0.49	0.49	0.55	0.55
Total Losses			12.8	16.4	12.3	15.5	16.1
Parameter	Units	Boiler 4		Boiler 5			
		Coal	Natural Gas	Coal	Natural Gas		
Dry Flue Gas Loss	%	5.64	4.77	5.45	4.93		
Moisture in Fuel Loss		0.50	0.00	0.64	0.00		
Moisture from H2 Comb Loss		4.07	10.63	3.97	10.78		
Air Moisture Loss		0.13	0.12	0.13	0.13		
Unburned Carbon Loss		0.60	0.00	0.50	0.00		
Radiation Loss		0.33	0.33	0.32	0.32		
Total Losses			11.3	15.9	11.0	16.2	

Figure 10 presents a bar graph summarizing the differences in total boiler losses when switching from coal to natural gas, for the five (5) boiler case studies.

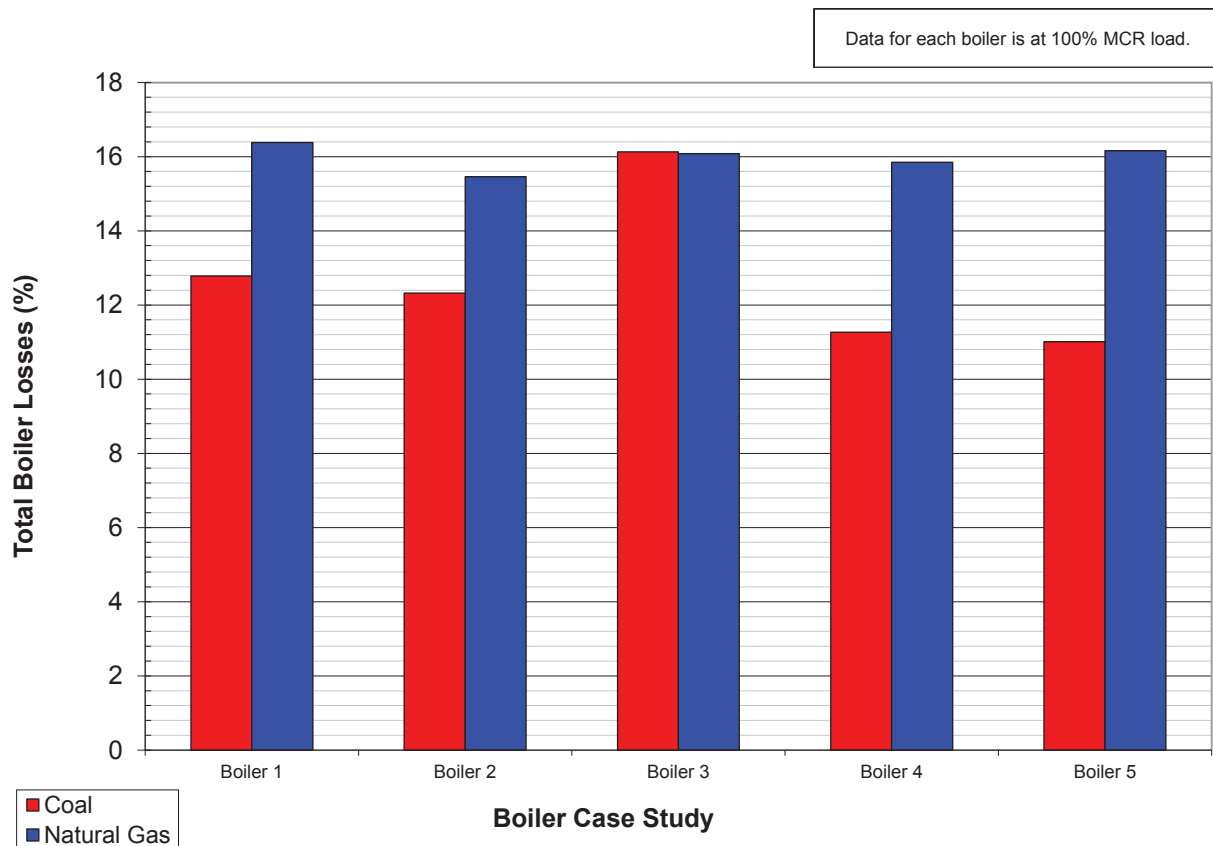


Figure 10 – Change in Boiler Losses for Coal vs. Natural Gas Firing

Attemperator Flow Evaluation

Typically when switching from coal to natural gas firing superheat spray attemperator flow will increase significantly. This is due to a hotter FEGT temperature, and the increase in superheater heat absorption effectiveness with natural gas firing.

Table 4 provides a summary of how the attemperator flow changes when switching to natural gas. Data is only provided for Boilers 3 and 4 because the other units don't have an attemperator system, which can be common for industrial boilers. Note however that main steam outlet temperature rose on Boilers 1 and 2 from 693°F to 717°F, and from 550°F to 584°F respectively. This was expected when switching from coal to natural gas firing, and is the reason why the additional spray was required for Boilers 3 and 4. Not enough data was available from Boiler 5 to make this comparison.

Boiler 3 uses a spray type attemperator which is typically found on utility sized boilers. One can see that the steam temperature entering the desuperheater rises when firing natural gas due to reasons previously described. Therefore spray flow must increase to regulate the final outlet temperature.

Boiler 4 uses a mud drum type attemperator where a portion of the steam is sent through a heat exchanger located in the mud drum. The mud drum contains the boiler water / steam emulsion, and is therefore at a lower temperature (saturation temperature) than superheated steam. This cools the

steam flowing through the desuperheater before mixing again with main steam flow prior to the boiler outlet. This type is more common on industrial boilers. For Boiler 4 only a direct comparison can be made at 75% MCR load because coal data at 100% MCR was not available. The data shows that in this instance the amount of steam bypassed to the mud drum desuperheater was mainly unchanged when switching to natural gas. The reasoning for this is that this boiler has screen tubes upstream of the superheater. The flue gas temperature leaving the screen and entering the superheater for both the coal and natural gas case was about the same, except the flue gas flowrate for natural gas firing was reduced.

Not all industrial units will have an attemperator system. However if steam temperature control is a plant requirement, a review of the attemperator impact is warranted.

Table 4 – Attemperator Data for Natural Gas Conversion Boiler Case Studies

Parameter	Units	Boiler 3		Boiler 4*		
		Coal	Natural Gas	Coal	Natural Gas	Natural Gas
Load	% MCR	100	100	75	75	100
Type of Attemperator Station		Spray		Mud Drum Desuperheater		
SH Temp Before Spray	°F	779	815	783	752	777
SH Temp After Spray	°F	755	760	707	691	709
Total Superheat Steam Flow	lb/hr	159,485	170,000	245,000	245,000	325,000
Spray Water Temp	°F	352	352	N/A		
Spray Water Flow	lb/hr	1,897	4,671			
Saturation Temp (Drum)	°F	N/A		527	527	537
Superheat Flow thru Mud Drum	lb/hr	N/A		61,781	57,008	75,097

*100% MCR coal data was not available for Boiler 4

Tube Metal Temperatures and Pressure Part Modifications

Tube metal temperatures for the boiler heating surfaces should be evaluated prior to performing a natural gas conversion. There are several factors identified in this paper that could affect tube metal temperatures. These factors include increased FEGT, increased absorption effectiveness of the heating surfaces, and a reduction in flue gas flowrate. While these factors contribute to both increasing and decreasing tube metal temperatures, a net increase in tube metal temperatures is generally observed when performing this fuel conversion.

Boiler 3 was used as an example to identify the need to upgrade pressure part materials due to increasing tube metal temperatures. Note not all of the 5 boilers outlined in this paper required material upgrades. The superheater on Boiler 3 contains four (4) inlet loops of SA210-A1 material, and one (1) outlet loop of SA209-T1. The study identified that the outlet loop was the primary concern when switching fuels. Table 5 summarizes the operating conditions of the outlet loop. The data shows that the calculated midwall temperature is within the limit for coal and natural gas firing conditions. However, the calculated outer wall temperature is above the oxidation limit for SA209-T1 when firing natural gas. Therefore, the particular study performed for Boiler 3 had recommended that the outer loop material be upgraded to SA213-T11 material. (See material diagram below in Figure 11.)

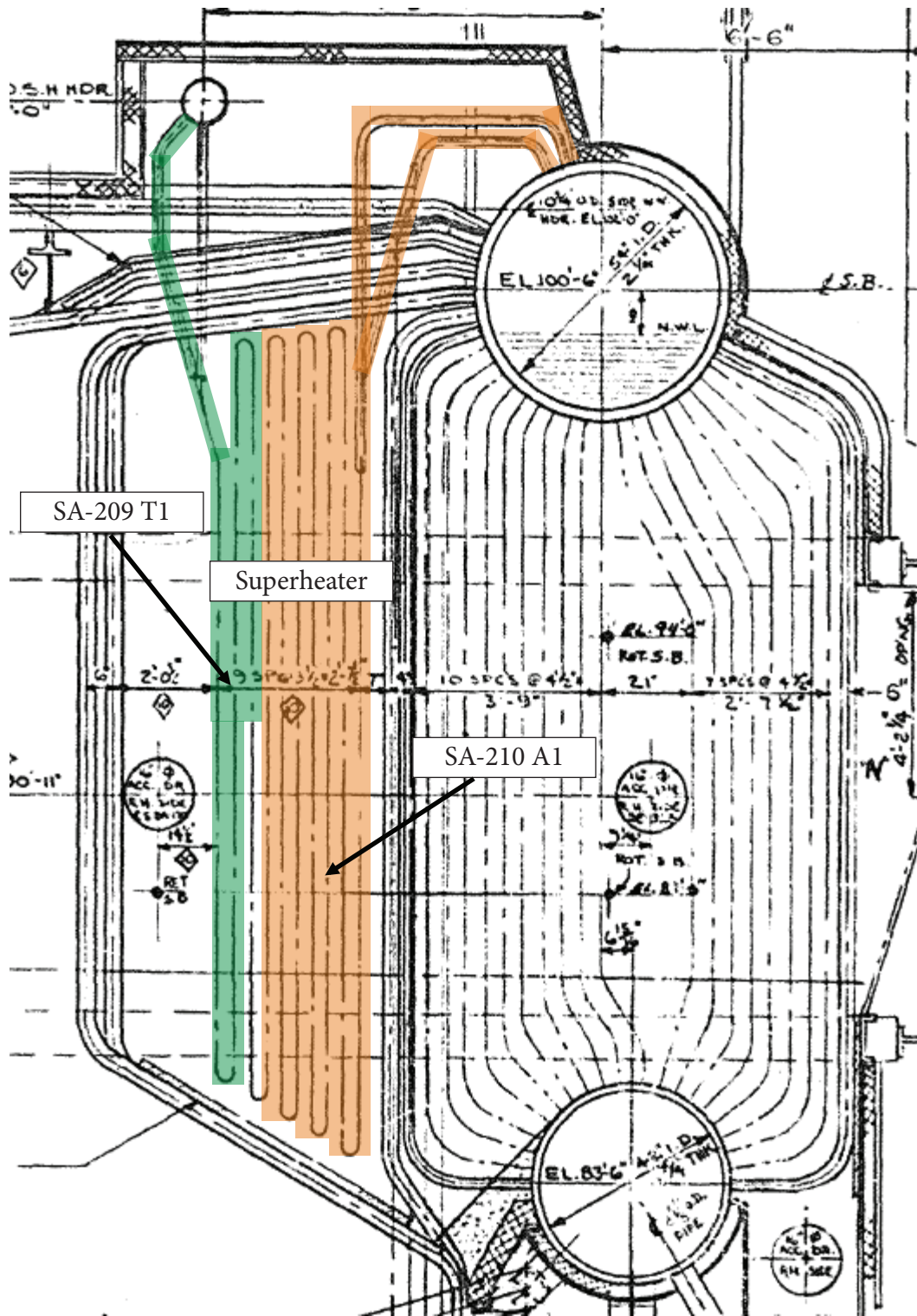


Figure 11 – Boiler 3 Superheater Tube Metal Diagram

Table 5 – Tube Metal Temperature Data for Natural Gas Conversion Boiler Case Studies

Parameter	Units	Boiler 3	
		Coal	Natural Gas
Flue Gas Inlet Temp	°F	1,650	1,916
Flue Gas Outlet Temp	°F	1,240	1,337
Steam Inlet Temp	°F	472	470
Steam Outlet Temp	°F	778	820
Calculated Tube Midwall Temp	°F	827	902
Tube Midwall Temp Limit	°F	1,017	1,017
Calculated Tube Outer Wall Temp	°F	829	904
Tube Outer Wall Temp Limit	°F	900	900

Another point to consider is that steam temperatures are likely to increase as well due to the same principles that cause the rise in tube metal temperatures. Depending on whether the boiler has a steam temperature control system, whether metal temperatures are permissible, or whether the plant has requirements for maximum steam temperature limits, plants may also want to consider the removal of heating surface. This would be another method to ensure the aforementioned criteria are met.

SUMMARY

This paper discussed the boiler and combustion system review that should take place when evaluating the prospect of converting a boiler from coal to natural gas.

The following combustion system parameters must be considered when converting from coal to natural gas.

- The firing configuration and burner performance should be coupled with the boiler thermal performance requirements.
- Emissions requirements need to be considered when selecting a combustion system design.
- The gas fuel supply should be designed for safe operation that meets the required boiler firing flexibilities.
- The burner management system needs to be updated to control to the new fuel.

The following changes in performance are typical when converting from coal to natural gas.

- Furnace exit gas temperature (FEGT) increases, due to the lower emissivity of the natural gas flame.
- Furnace water wall and radiant superheater absorption decreases, due to the lower emissivity of the natural gas flame.
- Natural gas fuel flowrates on a weight basis decrease over coal, due to a greater higher heating value for natural gas than coal.
- Dry air requirements to fully combust natural gas fuels increase over coal, but the amount of excess air required decreases.
- Combustion air and flue gas flowrates generally decrease when firing natural gas.
- Heating surface absorption effectiveness increases with natural gas due to the absence of ash in the fuel, which fouls heating surfaces in coal fired applications.
- Heat transfer through the convective heating surfaces increases, especially for surfaces near the furnace outlet. This is due to the increased FEGT and surface absorption effectiveness. This is offset somewhat by a decrease in flue gas flowrate. Note that heat transfer through downstream sections may decrease. This is due to the increased upstream absorption effectiveness and reduced flue gas flowrate, effectively reducing the net heat remaining in the flue gas by the time it reaches these sections.
- Total boiler losses increase significantly primarily due to the increase in the evaporation of water in the flue gas, formed during the combustion of hydrogen in the fuel. Natural gas has significantly more hydrogen than coal. This increase in loss is offset somewhat by a decrease in the dry flue gas loss, the elimination of the fuel moisture loss, and the elimination of the unburned carbon loss.
- Attemperator flowrates typically increase when converting to natural gas. This is due to higher steam temperatures as a result of the higher FEGT and increased surface absorption effectiveness.
- Tube metal temperatures may increase due to higher steam and flue gas temperatures. This may require upgrading pressure part materials.
- Pressure part modifications may be required if the plant has limits on the maximum steam temperature, if the unit doesn't have a means of steam temperature control, or if metal temperatures are above permissible limits.

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