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Technical Publication

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ABSTRACT

With availability of natural gas at competitive prices and increased scrutiny of coal-fired generation, conversion of coal-fired units to natural gas-firing is a popular option to consider as an alternative to capital-intensive environmental equipment upgrades or even retirement. Many owners are considering this option as a way to keep an existing plant open while meeting new and pending environmental regulations. There are many technical challenges associated with such a conversion and the owner should consider them all carefully on a case-by-case basis. This paper will present an overview of these challenges, with a focus on the steam generator and what an owner / operator needs to understand when considering conversion to natural gas-firing.

Typical effects of a conversion to natural gas-firing for a utility-scale coal-fired steam generator are discussed along with potential operational effects of such a project. A general discussion of differences in furnace and convective pass performance characteristics for the different fuels is presented along with a discussion of how these differences can translate to technical challenges in a conversion project. Typical effects on boiler efficiency and emissions as well as the most commonly required modifications are reviewed. Finally, a comprehensive review of the operational affects of the converted unit is presented.

INTRODUCTION

The idea of converting an existing coal-fired boiler to natural gas-firing is not new. The MIT Energy Lab published a report reviewing the feasibility and cost of such a conversion in 1986 with the ultimate goal of reducing sulfur oxide emissions¹. Today these conversions are being revisited as an alternative to capital intensive emissions control equipment for not only sulfur, but nitrogen oxides and even carbon dioxide. The use of natural gas co-firing was considered as a method of reducing NO_x and SO_x emissions by the Electric Power Research Institute (EPRI) in 2000². The co-firing option allows the benefits of emissions reduction through re-burning mechanisms as well as reduction in CO₂ by displacing some of the heat input from coal with natural gas without the large changes in boiler radiant and convective heat transfer characteristics.

High volatility in the price of natural gas has typically kept this option from being pursued until recent increases in natural gas production and storage have reduced and steadied the price of the fuel. The U.S. Energy Information Administration (EIA) has reported steady annual average Henry Hub spot prices for natural gas under \$8 / MMBtu through 2040 with prices staying below \$5 / MMBtu through 2025³. In some markets, rising coal prices and low gas prices are resulting in gas becoming less expensive than coal. These prices combined with rising capital investment requirements for coal-fired generation in order to stay compliant with new environmental regulations make a conversion to natural gas-firing an attractive option. A significant portion of coal-fired generation is projected to be retired as a result of increasing regulatory costs. SNL Energy reports more than 48 GW of coal-fired generation scheduled for retirement during the period of 2012 to 2020. A conversion to natural gas-firing is being considered more frequently as an alternative to retirement for these units. A reported 6,900 MW of existing capacity, approximately 14% of planned retirements, are planned for conversion to natural gas according to SNL Energy data⁴.

Reinhart et. al⁵ explored several different options for utilizing natural gas at plants facing retirement. The five options considered included (1) full conversion of the existing boiler to gas-firing, (2) co-firing gas and coal, (3) installation of additional emissions control equipment, (4) repowering the existing steam turbine with a new combustion turbine/HRSG combination and (5) complete replacement of the existing Rankine cycle with a new combined cycle. The study considered these options under a range of planned capacity factors, service life and fuel price scenarios and found that a full conversion of the existing boiler can be cost effective, particularly when lower service life is considered (10 years in lieu of 30 years). The determination of feasibility and economic viability of a fuel conversion project is complex and should be considered on a case-by-case basis. Should a switch to natural gas-firing be determined a viable, attractive option, the many technical challenges associated with the conversion as discussed herein should be carefully considered in order to achieve reliable, optimized unit operation post-retrofit.

FUEL SYSTEM MODIFICATIONS

When considering the conversion of an existing coal-fired boiler to fire natural gas exclusively, plans must be made to remove the existing coal equipment and install the necessary gas firing equipment. The new equipment required generally consists of a new natural gas fuel transport system (ie. gas metering station, pressure reducing station, piping, etc.), gas burners, ignitors and flame scanners. New logic designed for gas firing will need to replace the existing coal-based logic in the burner management system (BMS). Some logic will need to be modified in the combustion control system (CCS) as well since combustion air requirements and master fuel controls will be different when firing natural gas. All system designs will be required to meet current codes which may include NFPA 85, NFPA 497, NFPA 54 and NFPA 70.

Natural Gas Fuel Transport System

If natural gas is not currently available at the plant site then a natural gas pipeline capable of carrying natural gas from an existing commercial gas line to the plant will be required. All new gas pipeline installations will require the installation of a gas metering station and a pressure reducing station required to reduce line pressure from the supply pressure (typically 750 psig (51.7 bar) or 1,400 psig (96.5 bar) depending on location) to the plant's required design pressure and to meter the amount of gas consumed by the plant for billing purposes. Once gas is available within the plant site, each unit planned for natural gas-firing will require the installation of a unit specific gas valve station (designed to meet current NFPA 85 code) to monitor and control the flow and pressure of the gas being supplied to the unit. Control of the gas valve station is directly tied into the unit's distributed control system (DCS) system and master fuel controller which controls the gas demand to the new gas burners as required by load.

Gas Burners

Natural gas burner suppliers can typically re-use existing coal burner openings with little to no pressure part modifications in order to deliver the required fuel and air into the furnace for 100% MCR gas-firing. Gas burners are similar to coal burners in that they supply the required air and fuel mixture at design velocities required for proper fuel combustion within the furnace. Figure 1 is an example of a natural gas low-NO_x burner design for wall firing. Due to the favorable fuel properties of natural gas and the greater turndown capabilities of a natural gas burner (greater than 10:1 burner turndown in some cases) the gas burners can often be used to warm the unit during a cold start, allowing the use of smaller Class II or Class III igniters.

In some instances it is possible to retrofit the existing coal burners by replacing the coal components with gas components and re-using the existing air register while other times a complete burner replacement is required. Excess air levels required for gas-firing are much less than coal-firing (8-10% compared to 15-20% respectively). This change in airflow requirements generally leads to the need for smaller air register designs and possibly decreased fan duty which alternatively can be used for an induced flue gas recirculation (IFGR) system. However, on boilers requiring the use of more traditional flue gas recirculation (FGR) system the total combustion air [combustion air plus FGR] may be nearly the same mass flow as was required for coal-firing. In burner retrofit applications burner registers may need to be modified to maintain proper air velocities through the burners while new gas burners will usually be smaller than the previously installed coal burner unless FGR is required.

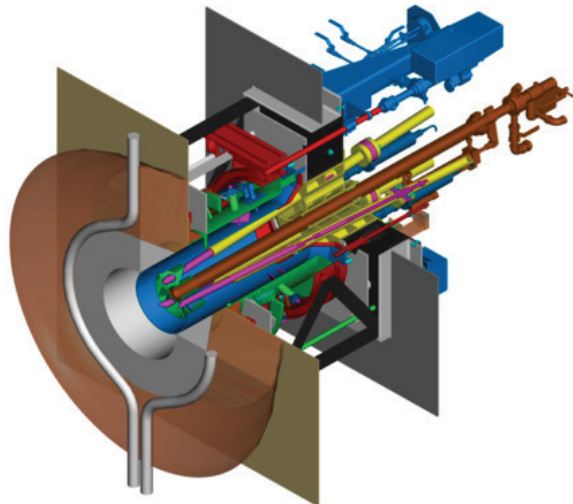


Figure 1 – Riley STS® Low-NO_x Natural Gas Burner

Ignitors

Gas burners and coal burners generally have different ignitor requirements due to the fuel differences and burner turndown limitations. Class I ignitors are usually required for coal burners due to the large amount of energy required to ignite the pulverized coal and, if required, provide flame stabilization as well as provide an ample heat source capable of warming up the unit. Gas burners have greater turndown capabilities and therefore can be used as the heat source for a cold unit start-up in lieu of Class I ignitors. The required energy to light-off a gas burner is much less due to the favorable ignition properties of the natural gas fuel, so a Class II or a Class III ignitor can be used in lieu of a Class I ignitor.

Less commonly used, but available for use with gas burners, are Class III-special ignitors which are often referred to as High Energy Spark Ignitors (HESI). HESI's are typically inserted into the burner's gas spray area and discharge a high energy electric arc which ignites the burner directly. It should also be noted that gas burner applications with FGR may require the ignitors to have their own combustion air source required to provide an ideal air/gas mixture capable of supporting proper ignitor light-off. Ignition of an ignitor flame can be difficult without the aid of combustion air where FGR is present since the FGR creates an oxygen deficient atmosphere. Table 1 provides a description for the different ignitor types⁶.

Table 1 – Comparison of Ignitor Classes

	Class 1	Class II	Class III	Class III-Sp.
Ignition of Main Burner	Coal, Gas	Coal, Oil, Gas	Gas, Oil	Gas, Oil
Heat Input	≥ 10% burner @ full load	4-10% burner @ full load	≤ 4% burner @ full load	N/A
Cont. Operation	Yes	Yes (w/ 2 scanners)	No. Light-Off Only	No

Flame Scanners

When switching to natural gas fuel, the flame scanners used to monitor flames within the furnace will need to be since there are significant differences in characteristics between the coal and gas flames such as the spectral intensity of radiation. There are three types of flame scanners typically used in boiler applications; ultra-violet (UV), infrared (IR) and flame rods. UV and IR scanners are typically those most utilized in utility boilers with the latter being most typical for coal-fired applications. While IR scanners monitor spectral radiation from flames at wavelengths greater than 800 μm , UV scanners monitor radiation wavelengths smaller than 400 μm . Some coal-fired units are equipped with combination UV/IR flame scanners and can be re-used for gas-firing with proper calibration by the scanner OEM.

PERFORMANCE CONSIDERATIONS

An obvious and major component in the evaluation of switching fuels is the supply of natural gas. When considering the change from coal-firing to natural gas-firing, one must also consider the changes in unit performance and the effect of such changes on the overall economic profile of the generating unit. The impacts of a switch from coal to gas are wide-ranging depending on the base fuel, unit characteristics and the final performance objectives. The authors have attempted to highlight the most influential of these changes in the following discussion. This paper does not represent a complete analysis of the impacts of a fuel conversion as this must be done on a case-by-case basis through a complete and thorough engineering study. The discussions herein are meant to guide an owner/operator in the potential effects of a conversion project. Black and Bielunis⁷ discussed the effects of converting a coal-fired boiler to natural gas, however, their discussion on thermal characteristics of a conversion were more focused on smaller industrial boilers with output less than 500,000 [lbs hr⁻¹] steam flow. While the same concerns are present with larger utility scale boilers, this paper seeks to focus on effects which can be expected for these larger units when converting from coal- to gas-firing.

Furnace Performance

A change in fuel will drive changes in the performance characteristics of the radiant furnace. These characteristics are (a) the radiant heat flux profile in the furnace walls, (b) the portion of radiant heat transferred to the upper furnace, both steam and water cooled, (c) the portion of radiant heat transferred directly to the furnace outlet plane, and (d) the resulting furnace exit gas temperature (FEGT). The changes to these characteristics are the most important parameters in determining the performance of a converted unit since they have a large impact on the convective performance of the downstream surfaces.

The FEGT can either increase or decrease when switching from coal-firing to gas-firing depending on the base fuel and furnace characteristics. A utility furnace is designed to meet several criteria including fuel burnout, velocity requirements for convection, ash deposition and erosion, and gas temperatures based on the material limits in the radiant and convective surfaces. Typically, a furnace designed to fire natural gas will be much smaller than one designed to fire coal. This is due to the fact that fuel burnout is much faster and there is no ash to consider for erosion or deposition which many times results in higher allowable FEGTs. Additionally, when there is no ash deposition to inhibit heat transfer to the furnace walls and the distribution of fuel/air in the furnace is more even, higher heat release rates are possible. As a result, a unit designed to fire a medium to high slagging coal will likely have a large furnace and low heat release rate much lower than necessary for gas-firing. A typical gas furnace can have a design area heat release rate approximately 2.5 times greater and a volumetric heat release rate 2.2 times greater than a typical coal-fired unit with equal rated output. This large difference in design criteria make it clear that a complete and detailed analysis of the furnace performance is necessary when converting a coal-fired unit to natural gas-firing.

Figure 2 shows FEGT as a function of the furnace area heat release rate for various fuels for front wall-fired boilers. It can be seen that if the base fuel is a western sub-bituminous coal such as that from the Powder River Basin (PRB) with a medium to high heat release rate, the FEGT will decrease for gas-firing while for a low slagging base coal the FEGT can be expected to increase when firing gas. The wide range of possible FEGT values for any given heat release rate when firing coal necessitates a case-by-case evaluation of the furnace performance for each unit being considered. During a unit-specific feasibility study, the furnace characteristics would be calculated based on operating parameters and unit design information and calibrated using operating data obtained from the unit.

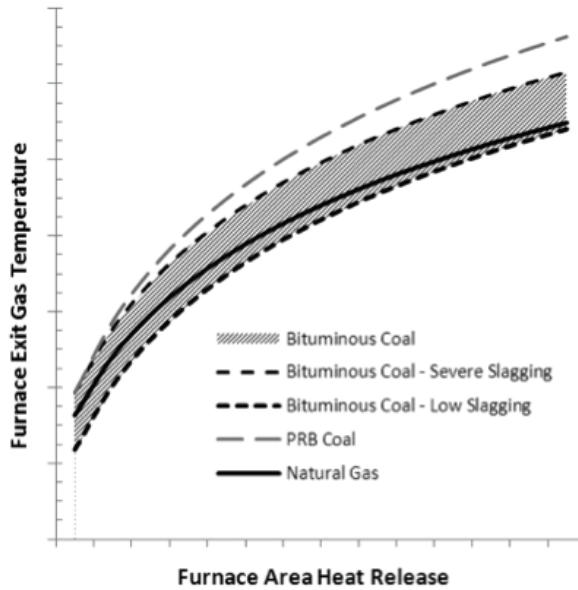


Figure 2 – FEGT as a function of area heat release

A coal flame is much more emissive than a natural gas flame. Radiation from a coal flame is significantly enhanced by the presence of carbon/soot particles which radiate at nearly black-body emissivity. Thermal radiation from a flame containing soot can be 2-3 times that of a flame without soot⁸. Thermal radiation is proportional to the fourth power of the temperature. The adiabatic flame temperature is a function of the heat content of the fuel and the flue gas properties and can be calculated via Equation 1 below⁹.

$$T_{F,ADB} = \frac{LHV_{fuel} + H_{sens.air}}{W_{flue\ gas}} \quad (1)$$

The adiabatic flame temperature is theoretical and much higher than what is actually sustained in the flame since some heat is lost from the flame to the furnace during combustion and also due to the dissociation of CO₂ at temperatures above 3,000 °F (1,648 °C). Generally, a higher heat content fuel with low moisture will result in higher flame temperatures. The excess air in the furnace acts to dilute the combustion products, thus lowering the peak flame temperature. For reference, a bituminous coal burned at 20% excess air will have an adiabatic flame temperature near 3,300 °F (1,816 °C), while a high moisture, low heat content PRB coal with the same excess air would have a flame temperature closer to 2,950 °F (1,621 °C). A representative natural gas flame will have an adiabatic temperature near 3,200 °F (1,760 °C) at 20% excess air and near 3,500 °F (1,927 °C) at 10% excess air.

While the radiation from a gas flame is generally lower than that for a coal flame, due to higher moisture content the flue gas emissivity is actually higher for gas-firing than for coal-firing. Depending on the upper furnace geometry and proximity to the main burner zone, the radiation heat transfer to upper furnace surfaces can increase or decrease when switching from coal- to gas-firing. Further, the amount of radiant heat transferred directly to the furnace exit plane and into the first convective surface will depend on the case-specific furnace geometry and fuel characteristics. Analysis of a radiant furnace system is complex, requiring detailed calculations for radiant gas properties, including the effects of particles such as char, soot and ash as well as geometric properties such as radiant exchange factors.

Further complicating the analysis are the effects of ash deposition on the radiant surfaces. Typically, this can be accounted for by utilizing a calibrated furnace model based on operating data available from the unit. However, when making a major change such as a fuel conversion, it is challenging to identify how these different furnace characteristics will change when the gaseous fuel is burned in the furnace. Surface emissivities must be adjusted to account for the elimination of ash deposits which can significantly reduce the absorption to those surfaces when firing coal. Although powerful computer models allow the evaluation of such complex systems, engineers must still rely heavily on experience when analyzing these systems.

Steam Conditions

Once the furnace performance has been reliably predicted for the natural gas-firing case, the convective pass heat transfer must be evaluated with the new gas flows, temperatures, direct furnace radiation (DFR) and radiant superheater absorptions. This analysis will provide the predicted steam temperatures when firing natural gas.

Table 2 - Combustion parameter comparison with different fuels.

		Bit. Coal	PRB Coal	Nat. Gas	Nat. Gas
HHV	Btu/lb	14,100	8,223	23,143	23,143
Excess Air	%	20.00	20.00	20.00	10.00
Dry Air Req.	lb/lb	12.85	7.51	19.68	18.04
Dry Air Req.	lb/10kBtu	9.12	9.13	8.50	7.79
Dry F.G. Prod.	lb/lb	13.36	7.75	18.57	16.93
Wet F.G. Prod.	lb/lb	13.95	8.56	20.94	19.27
Wet F.G. Prod.	lb/10kBtu	9.9	10.41	9.05	8.33

A typical coal requires approximately 9.1 lb/10kBtu (0.39 kg/MJ) of combustion air, while natural gas only requires approximately 8.5 lb/10kBtu (0.37 kg/MJ) at 20% excess air. This combined with a typical excess air level while burning gas of roughly half that required for burning coal results in an approximate 14.5% decrease in the total required combustion air for gas-firing at the same heat input. It follows that while a typical coal combusts to produce approximately 10.4 lb/10kBtu (0.45 kg/MJ) of flue gas, natural gas combustion produces only 8.3 lb/10kBtu (0.37 kg/MJ) of flue gas. The result is approximately 16-20% less flue gas flow from the furnace while firing gas. Table 2 summarizes the comparative parameters for two different coals and natural gas.

Thus although the gas temperatures entering the convection sections (FEGT) can typically be higher than that for coal-firing, the lower flue gas mass flow rates while firing gaseous fuel will often result in a net decrease in convective absorption. Convective heat transfer in a tube bundle can be described by the following general equation:

$$Q = UA\Delta T_{LMTD} \quad (2)$$

where,

$$U = \frac{1}{\sum h_i} \quad (2a)$$

U is the overall heat transfer coefficient with the combined effects of conduction in the tube wall, convection on the inside and outside surfaces and thermal radiation. The change in flue gas mass flow will result in a change in the outside convective heat transfer coefficient and ultimately the overall exchanger coefficient, U . An increase or decrease in FEGT will affect the temperature difference, ΔT_{LMTD} . In a unit experiencing an increase in FEGT, the first convective section will often experience an increase in absorption as shown by Black et. al⁷. Although this first surface would likely see an increase in absorption due to higher available energy and greater ΔT_{LMTD} , downstream surfaces often see diminished effects of the higher FEGT and suffer a decrease in absorption due to the lower gas flow. When the absorption of a surface increases, there is a chance that the tube metal temperatures experienced in that surface will exceed the allowable temperature for the material. In this case a material upgrade might be necessary or a reduction in unit load in order to reduce the temperatures below the material allowable limit.

In addition to the above effects, one must account for the change in bundle effectiveness due to cleanliness regarding the presence of ash deposits on convective surfaces. This is an engineering challenge to determine the appropriate level of adjustment for these factors since data is often not available for the thickness, location and properties of such as deposits. Engineering judgment and experience must be relied upon for this assessment. Convective effectiveness can increase up to 15% depending on the base coal and ash deposition characteristics. Determining the effects of ash on the heat transfer in a boiler is highly dependent upon the case-specific parameters including fuel/ash composition, gas temperature profiles, etc. Good engineering judgment and experience with a range of fuels and applications are required in order to determine how to account for the change in these characteristics when firing ash-free natural gas.

Utility scale boilers will typically experience an overall decrease in convective absorption in SH and RH sections, and thus decreasing main steam and reheat steam temperatures to the turbine. In order to recover lost convective heat transfer, flue gas recirculation (FGR) is often utilized in order to increase the mass flow of gas from the furnace and through the convections sections. FGR can be accomplished with several different configurations depending on the objectives and flow requirements. For relatively low required FGR flow, induced flue gas recirculation (IFGR) using the existing FD fan can be utilized. IFGR, however, will further increase the duty of the FD fan and will limit the temperature of the flue gas recirculated based on the limitations of the existing fan materials. The alternative is to add a new FGR fan, which can be designed specifically to meet the demands of the system across the desired load range. Flue gas is generally taken from the economizer exit and recirculated back to the furnace via the windbox, lower furnace or upper furnace. Mixing the flue gas with the combustion air in the windbox and through the burners provides an additional benefit of reduced NO_x production. While FGR systems are often taken out of service on coal-fired boilers due to high maintenance costs, the ash-free flue gas for gas-firing makes for a much less maintenance intensive system. Figure 3 shows a comparison of the specific energy in the flue gas entering each surface of an example unit analyzed for gas conversion. In this example FGR was added in order to recover some of the energy to achieve original steam condition while firing natural gas. The gas enthalpies shown are normalized using the furnace exit enthalpy for the base coal.

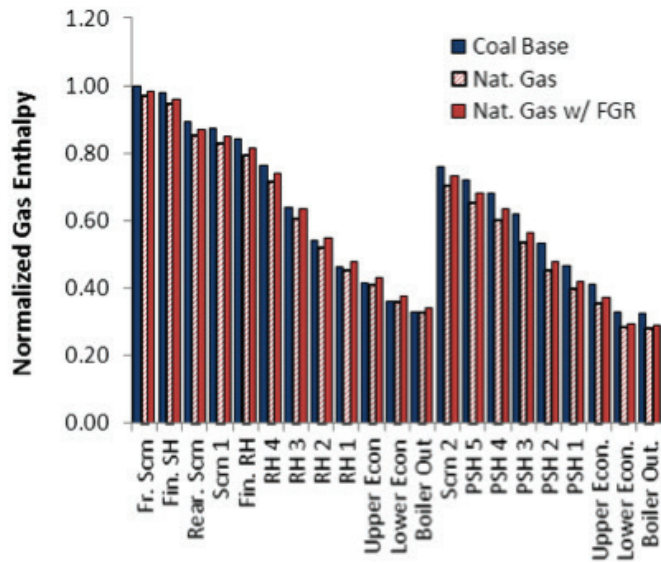


Figure 3 – Relative Gas Energy Profiles (PRB Base Coal)

Pressure part modifications can also be a solution to the reduced convection effectiveness. Redesigning the pressure parts to accommodate gas-firing will allow the most optimization for performance but likely also require the highest capital investment. However, if there are sections of the SH or RH which are at the end of their useful life and scheduled for replacement, a redesign might be a good option to recover lost performance when firing natural gas.

Capacity

There are several factors that have the potential to limit the load capability of a converted unit including the ability of the forced-draft (FD) fans to supply sufficient combustion air, and maximum allowable metal temperatures in the superheaters and reheaters. As discussed above, if the convective heat transfer is too high in the superheater or reheater such that material temperature limits are exceeded, the unit may require a load reduction if pressure part modifications are not desired. Pressure part modification in this case could involve material upgrades, the addition/upgrade to spray attemperation stations, or the complete redesign of SH and/or RH surface to accommodate gas-firing and optimize boiler performance. A detailed review of the predicted metal temperatures is required to ensure that the existing materials are not exceeded when firing natural gas. This will be particularly important on any units not equipped with spray water attemperation systems for steam temperature control.

Additionally, when firing coal, a portion of the combustion air is supplied to the furnace as transport air for the solid fuel. With the gaseous fuel, all combustion air will be supplied through the windbox via the forced-draft fan(s). While the total amount of combustion air required to combust natural gas is less than that required for coal, the amount being supplied by the FD fan(s) will typically be higher.

For a utility unit firing coal and requiring approximately 30% of total combustion air as transport air through the primary air system, a conversion to natural gas will result in approximately 22% more air being supplied by the FD fans. For this reason, the FD fan capacity should be evaluated in order to confirm their ability to supply the required air flows for gas-firing. If the existing fan capacity is not sufficient, the unit will either require a load reduction or modifications to the FD fan in order to increase capacity. For centrifugal fans, tipping the fan blades can typically provide up to approximately 7% more flow at 15% higher static pressure, but can require up to 27% greater shaft power.

Boiler / Plant Efficiency

As discussed earlier regarding the combustion air requirements, natural gas-firing requires lower total air flows and produces lower flue gas flow rates for the same heat input. The lower gas flow results in lower dry gas losses when firing natural gas in lieu of coal. This lower dry gas loss contributes to an increase in boiler efficiency. On the other hand, the higher hydrogen content in the gaseous fuel typically will lead to a significantly higher moisture loss, negatively impacting the boiler efficiency. The increase in boiler efficiency due to lower gas losses and no unburned carbon loss will typically not be greater than the negative impact of higher moisture losses due to hydrogen combustion. The net result is up to a 5% reduction in boiler efficiency for a unit converted to burn natural gas. Table 3 shows an example of the differences in the major efficiency losses for coal and natural gas in the same unit at rated load. The data in Table 3 shows that for a coal with high moisture, the efficiency reduction for gas-firing is small while that for a unit burning a low moisture bituminous coal will be much higher.

A change in the boiler efficiency will impact the overall Unit Net Heat Rate (UNHR). The boiler efficiency is inversely proportional to boiler efficiency according to Eqn. 3 below:

$$UNHR = \frac{1}{\eta_b} TCHR \quad (3)$$

Thus, a 5% reduction in boiler efficiency will result in an approximate 5% increase in heat rate. The increase in heat rate due to boiler efficiency is typically partially offset with a decrease in net heat rate due to reduced station load resulting from the elimination of fuel handling equipment such as coal pulverizers and PA fans as well as the removal of any existing flue gas cleaning equipment from service.

Table 3 - Boiler efficiency comparison with different fuels.

Parameter		Bit. Coal	PRB Coal	Nat. Gas
Dry Flue Gas Loss	[%]	5.97	6.01	4.66
Moisture (Liquid) in Fuel Loss	[%]	0.24	4.16	0.00
Water from H2 Combustion	[%]	3.31	4.53	10.63
Air Moisture Loss	[%]	0.14	0.14	0.12
Unburned Carbon Loss	[%]	0.09	0.09	0.00
Radiation Loss	[%]	0.17	0.17	0.17
Unaccounted Loss	[%]	0.50	0.50	0.50
Total Loss	[%]	10.42	15.60	16.08
Boiler Efficiency	[%]	89.58	84.40	83.92

The values in Table 3 assume like conditions at the regenerative air heater. The air heater performance will be altered when switching from coal- to gas-firing since the flow rates are changed as well as the ratio of air to flue gas. Regenerative air heater performance is dependent on the specific heat ratio, known as the “X” ratio, as follows:

$$X = \frac{(\dot{m}c_p)_{air}}{(\dot{m}c_p)_{gas}} \quad (4)$$

A 10% decrease in X will result in a decrease of boiler efficiency of approximately 0.75%¹⁰. Assuming an average air and flue gas temperature of 500 °F (260 °C), a conversion to gas-firing results in a net decrease of approximately 0.4% boiler efficiency for the bituminous coal base fuel and an increase of approximately 0.23% for the PRB base fuel. Since while firing natural gas all the combustion air will be routed through the existing secondary air system, units with tri-sector air heaters can be modified at the air heater inlet and outlet ducts in order to connect the secondary and primary sectors of the air heater. This will allow the use of 100% of the heat transfer surface available in the air heater. In addition to the boiler efficiency changes, any changes in the steam conditions can affect the UNHR as well by changing the turbine cycle heat rate (TCHR). Figure 4 shows a typical heat rate correction to the TCHR for a given reduction in the steam temperatures¹¹.

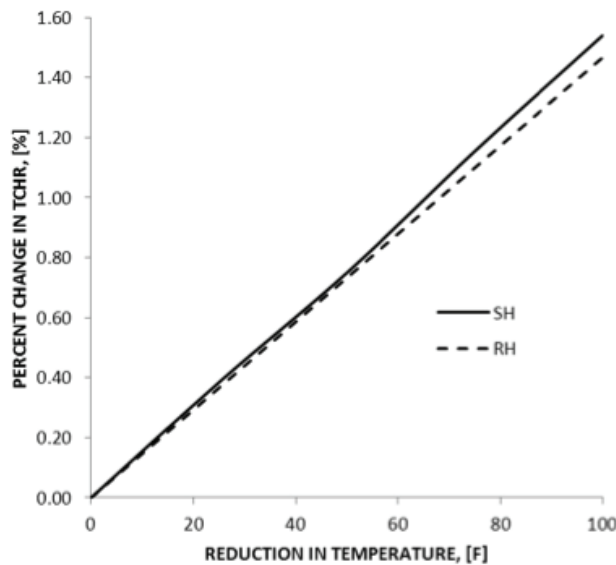


Figure 4 – Correction to heat rate for a reduction in steam temperature

The change in steam temperatures, superheat and reheat, will be dependent on the units configuration for steam temperature control as well as the changes in heat transfer performance. For units with gas proportioning dampers, a larger reduction in RH temperature than SH is typical and any correction to increase steam temperature will typically avoid the use of RH spray attenuation. For units without gas proportioning dampers, the changes in heat transfer characteristics along with potential corrections to steam temperature (burner tilt or FGR addition) can result in a need for RH spray attenuation. The positive effect on heat rate for increased SH steam temperature should be balanced with the negative effects of RH spray in this case. In general, a 2% increase in heat rate will be incurred for every 1% increase in RH spray flow.

Emissions Performance

Natural gas-firing offers lower sulfur (SO_x), mercury (Hg) and particulate matter (PM) emissions given that there is little to none of the required precursors present in natural gas. This makes a switch to natural gas-firing an attractive option from an environmental compliance perspective. In addition to the above historically regulated emissions, natural gas-firing provides a competitive advantage when considering carbon restrictions as it produces roughly 68% less CO₂ than the reference bituminous coal and approximately 78% less than the reference PRB for the same heat input. More generally, CO₂ emissions from a natural gas-fired boiler will typically be 50% or less than that of a similarly rated coal-fired boiler.

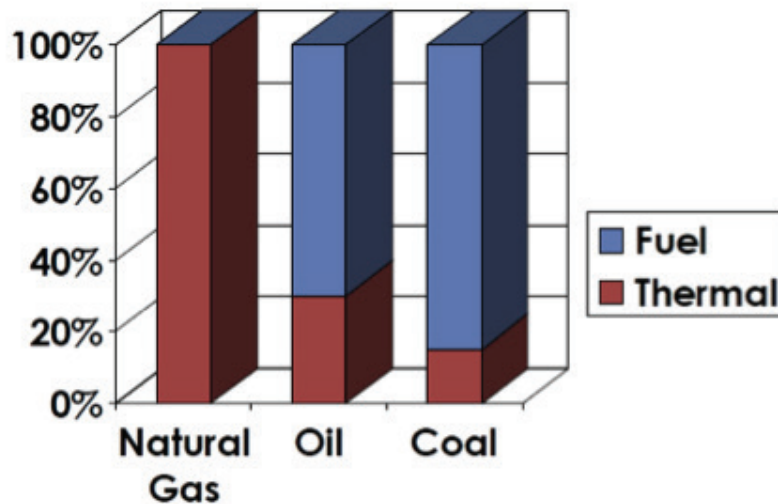


Figure 5 – Relative NO_x production by mechanism for different fuels

In general, gas-firing will produce roughly one third or less of the NO_x emissions produced from coal-firing. As shown in Figure 5, roughly 80-90% of NO_x generated from coal combustion is due to Nitrogen in the fuel which converts to NO_x during the combustion process. Since there is little to no nitrogen in natural gas, almost all of the NO_x produced from natural gas combustion is via the thermal NO_x mechanism. The mechanism for thermal NO_x production is a function of temperature, mixture composition and time within the combustion process. Typical NO_x control technologies employ some form of air or fuel staging. Low NO_x burners employ internal air and fuel staging while the addition of over-fire air (OFA) employs external staging of the air in the furnace. In general, gas-firing will produce roughly one third or less of the NO_x emissions produced from coal-firing. As shown in Figure 5, roughly 80-90% of NO_x generated from coal combustion is due to Nitrogen in the fuel which converts to NO_x during the combustion process. Since there is little to no nitrogen in natural gas, almost all of the NO_x produced from natural gas combustion is via the thermal NO_x mechanism. The mechanism for thermal NO_x production is a function of temperature, mixture composition and time within the combustion process. Typical NO_x control technologies employ some form of air or fuel staging. Low NO_x burners employ internal air and fuel staging while the addition of over-fire air (OFA) employs external staging of the air in the furnace.

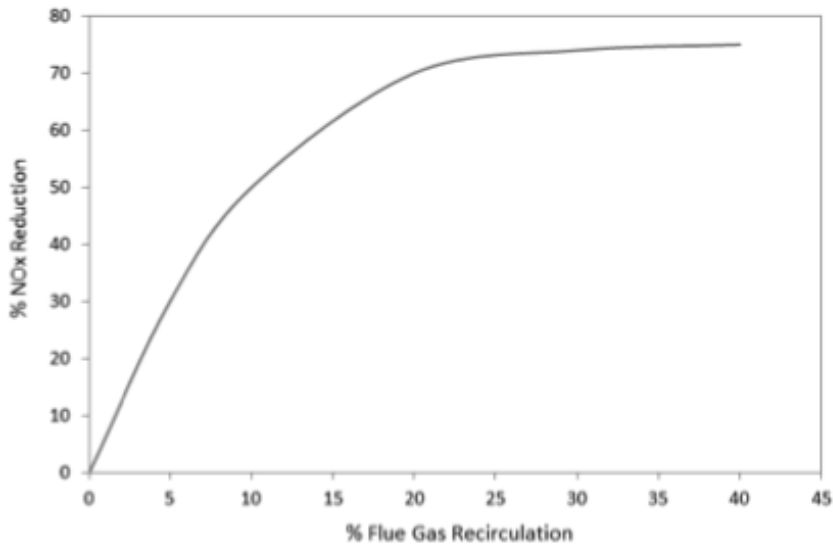


Figure 6 – NOx reduction by application of FGR

Additional measures can be taken to further decrease NOx levels including the use of FGR as mentioned earlier. FGR works in two ways: 1) the cooler flue gas acts as a dilutant, absorbing heat from the flame and lowering the peak flame temperatures and 2) by reducing the level of oxygen in the combustion air, starving the NOx forming reaction of oxygen. A unit converted from coal to natural gas that is equipped with an FGR and OFA system can reduce NOx by greater than 75%. An example of typical reduction in NOx via the application of gas recirculation is shown in Figure 6.

OPERATIONS, MAINTENANCE AND RELIABILITY

In addition to the performance impacts of the natural gas conversion, there are many changes in the operation and maintenance plans for a unit that must be considered. When an existing boiler is converted to gas-firing, coal feeders, conveyors and mills are all replaced with a gas metering station and a flow control valve station. Coal equipment requiring constant upkeep and wear component replacement is no longer necessary and replaced with only a handful of valves requiring a valve rebuild only every several years. Maintenance programs and spare parts inventory are greatly reduced after a fuel conversion to natural gas.

Coal Ash Effects

The North American Electric Reliability Corporation’s (NERC) Generating Availability Database System (GADS)¹² shows that the largest cause of lost generation in coal-fired generators is the boiler tube leak. A comparison of tube leak statistics for coal- and gas-fired boilers shows that gas-fired boilers experienced approximately 83% less lost generation due to boiler tube leaks than their coal-fired counterparts. The deposition of coal ash in the boiler will increase gas temperatures and, in-turn, can often elevate tube metal temperatures above their design limits reducing the strength of the material and eventually resulting in rupture. This combined with the erosive characteristics of the coal ash flowing through the boiler make ash-related issues the root cause of a large portion of all tube leaks in coal-fired boilers. The impact of ash-related problems in coal-fired utility boilers is estimated to be on the order of hundreds of millions of dollars annually in the U.S. and managing these issues has been the subject of many technical conferences and papers¹³.

Coal ash, the inorganic non-combustible portion of the fuel, represents a large portion of the many challenges that must be dealt with when firing coal. In addition to the deposition of ash on heating surfaces discussed previously, many coal-fired boilers suffer from the erosive effects of the ash contained in the fuel. From erosion wear of major components in the boiler's firing systems to erosion of tubes in the convective sections of the boiler; ash-related erosion is a major source of problems in many coal-fired boilers. In addition to erosion, other problematic characteristics of ash include stack PM emissions, and the removal and disposal of the ash downstream of the boiler. Since natural-gas contains no significant amount of ash material, the fuel conversion would eliminate these concerns from the O&M profile of the unit. Although most of the effects of coal ash negatively impact the economic profile of a generating unit, in the case of saleable flyash, coal ash can represent a positive revenue stream which would be lost in a conversion to natural gas-firing.

Fuel Quality

Fuel quality related issues are common for coal-fired boilers as the heating value, nitrogen, sulfur and inorganic constituents vary based on the mine and vane from which they were extracted and blended before being delivered to the plant. Many generating companies have placed significant emphasis on this issue through more stringent contracts, requiring a tight range on key quality parameters. With many owner/operators being driven to off-design fuels by stringent pollution regulations, fuel quality is definitely a major concern for coal-firing. Natural gas quality is generally much more stable and exhibits much less variability and therefore fuel quality is not typically an issue with gas-firing.

Operational Flexibility

In some cases it may be desirable to maintain the ability to fire coal when considering a conversion to natural gas-firing. This option can include the capability to fire 100% of both fuels or some relative percentage of both. Dual firing will result in a large amount of operational and economic flexibility for the owner and has been successfully applied to utility boilers¹⁴, but is not feasible in all applications. Figure 7 shows an example of a coal/natural gas dual-fuel low-NO_x burner. Just as was discussed regarding furnace performance, burner requirements are different for coal- and gas-firing leaving the ideal burner design for coal firing less than optimum for gas firing and vice versa. In addition, the additional burner components required for adding gas firing capability to an existing coal burner (while maintaining coal-firing capabilities) will restrict airflow which increases air velocity and pressure drop through the burner. These changes will effect the performance of the burner when firing both coal and natural gas. Also, physical space can be restricted and may not allow for all gas firing components required for full load gas-firing to be appropriately installed.

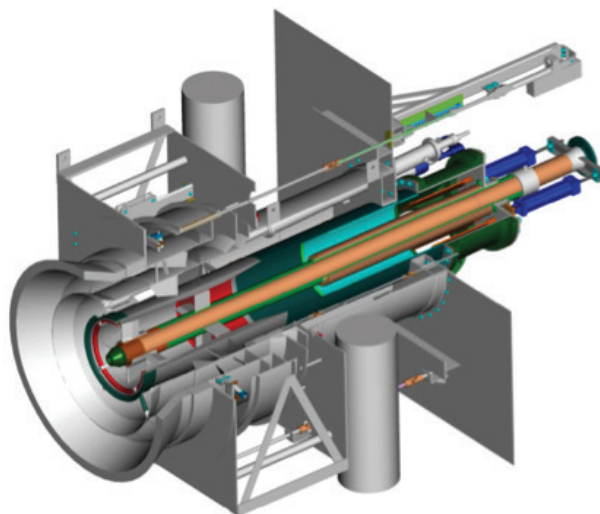


Figure 7 – Riley VS III® Dual Fuel Low-NO_x Burner

CONCLUSIONS

The potential changes in performance, operations and maintenance when switching from coal- to natural gas-firing have been considered and discussed thoroughly along with a brief overview of the required modifications. It has been demonstrated that understanding the furnace performance is key in understanding the potential impacts of the fuel switch on the performance of the boiler. Key parameters include base fuel composition and heating content, furnace geometry and firing configuration. The changes in furnace performance will ultimately effect the downstream convective surfaces and overall boiler performance. While overall performance changes are case-specific, in general utility boilers will experience a decrease in convective heat transfer and depressed steam temperatures as well as decreased boiler efficiency. Emissions performance is significantly better on gas-firing due to the lack of fuel-bound nitrogen, sulfur and ash. NO_x emissions are approximately 30% of the equivalent coal-fired emissions while producing less than one half the carbon dioxide of coal-firing, no SO_x and Hg and virtually no PM.

There are many benefits to gas-firing in lieu of coal-firing with respect to the overall O&M profile of the unit including the reduction of auxiliary power consumption by eliminating the need for equipment such as coal supply equipment, coal mills, primary air fans and flue gas cleaning equipment. Natural gas-firing offers additional flexibility in boiler turn-down as well as eliminating the negative effects of coal ash such as slagging/fouling and erosion. Dual-fuel capability as demonstrated by Courtemanche et. al¹⁴ can be considered for additional flexibility allowing the operation of the unit on 100% coal-firing or 100% natural gas-firing or any combination thereof.

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