CONVERSION OF EXISTING COAL-FIRED BOILERS TO NATURAL GAS FIRING

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ABSTRACT

An increasingly stringent and uncertain regulatory environment and falling natural gas prices have made converting existing coal-fired steam-generating boilers to natural gas firing more and more attractive.

This paper provides a general assessment from a sampling of projects that have converted coal-fired steam-generating units to 100% natural gas firing. We present an approach to assess the project technical feasibility, including boiler thermal performance modeling and project planning. Balance-of-plant considerations, such as National Fire Protection Association code compliance, natural gas piping system, air pollution control equipment, draft systems, and retirement of existing coal equipment are also discussed.

A case study of one recently implemented natural gas conversion project is presented.

1. INTRODUCTION

This paper provides a general assessment of projects that have converted coal-fired steam-generating units to 100% natural gas firing. We present an approach to assess the projects' technical feasibility, including boiler thermal performance modeling and project planning. Balance-of-plant considerations, such as National Fire Protection Association (NFPA) code compliance, natural gas piping system, emissions control equipment, draft systems, and retirement of existing coal equipment are also discussed.

1.1 Quality and Variability of Natural Gas

Historically, natural gas supply has been consistent in quality and heating value throughout the United States. Gas properties have also been consistent, with slight variations, making the risk of a significant error in engineering and design of gas-fired equipment quite low. Table 1-1 offers a representative fuel analysis for natural gas.

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Table 1-1. Sample Natural Gas Fuel Analysis

Parameter	Value
Relative density	0.580 lb/ft^3
Higher heating value (HHV)	1002 Btu/ ft^3 22,665 Btu/lb
Constituent (%)	
N_2	0.340
CO_2	1.690
Methane	96.700
Ethane	1.250
Propane	0.005
N-Hexane	0.003
N-Butane	0.006
Isobutane	0.005
i-Pentane	0.002
Isopentane	0.000
Sulfur compounds	<0.001
Moisture (lb/MCFD)	0.000

Recent exploration and drilling techniques have led to an increase in the amount of gas discovered and extracted, driving supply up and prices down. Gas is now being recovered from many sources. Biogas and syngas are being manufactured, creating variations in constituents and proportional gas makeup. Recently, we have observed “natural gas” deviating from the norm and affecting the predicted performance of gas-fired boilers and potentially requiring special equipment for emissions control; therefore, it is highly recommended that the makeup of fuel(s) intended to be fired in the boiler during the project planning phase be fully understood.

1.2 Natural Gas Availability

Low prices and regulatory pressures have created a swell in demand for natural gas, but the domestic distribution system has finite capacity, and in some areas of the country, already lags current demand. This is an acute problem in the northeastern United States where gas delivery infrastructure is already capacity-limited during the winter heating season. Efforts to increase pipeline capacity are complex and contentious because of political, environmental, safety, and other concerns.

When considering a coal to natural gas conversion it is an obvious advantage if the utility boiler is located close to an existing natural gas supply line with adequate surplus capacity, rather than one located many miles away from a pipeline that is at or near capacity.

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Utility generating stations in some areas of the country are distant from available gas pipelines, and thus fueling the unit may not be feasible and justification for a gas conversion may prove difficult or not possible.

2. TECHNICAL CONSIDERATIONS

2.1 Feasibility

Firing natural gas avoids the slagging and fouling conditions associated with coal combustion, which improves boiler cleanliness and tends to increase heat absorption. However, combustion-zone radiation rates to the furnace walls tend to be lower. Achieving design steam temperatures and full boiler output can be difficult for a boiler originally designed to burn coal. Higher tube-metal temperatures may be experienced when firing natural gas. In some cases, a unit derate of 15% or more, may be necessary to reduce flue gas and tube-metal (superheater, reheater) temperatures in the furnace and convection pass unless upgrades are made to tube material or attemperator nozzles are modified. In other cases, steam temperature derates are seen, since a reduction in excess air is needed for natural gas combustion, which reduces the flue gas flow rate and rate of heat transfer. There are several boiler parameters responsible for the unit and steam temperature derates, which include boiler/burner technology and furnace heat input/plan area ratio. Boiler natural gas feasibility studies are required to determine the effects of burning natural gas in a coal-fired boiler.

Coal and ash handling equipment are not required if firing natural gas; in most cases, these will be abandoned in place or will be removed to the extent necessary to carry out the conversion. In rare circumstances, the Owner elects to remove this equipment for maintenance, personnel access, or even for aesthetics.

Original forced draft (FD) and induced draft (ID) fans and other boiler auxiliary equipment are usually adequate for firing natural gas but sometimes need to be modified or replaced entirely.

2.2 Estimated Boiler Performance and Expected Plant Performance

Converting a boiler to natural gas typically decreases boiler efficiency because of the large quantity of hydrogen in natural gas. During combustion, the hydrogen is converted to water. Evaporating this water uses a portion of the flue gas energy, thus, lowering boiler efficiency. This efficiency loss is offset somewhat by the lower amount of excess air required to burn natural gas. Boiler efficiency decreases are to be expected in the 3% to 4% range, depending on the current fuel and boiler design. Auxiliary power demand is reduced with natural gas firing because pulverizers, primary air (PA) fans, precipitators, coal handling system, sootblowers, and other equipment are no longer required. Instrument air and service water will also decrease accordingly.

Net Plant Heat Rate (NPHR) could change ±2% due to the changes in boiler efficiency, power output limitation, and auxiliary power usage. More accurate NPHR estimates can be calculated based on unit-specific design and operating parameters.

2.3 Cycling

Cycling operation might be required when switching to natural gas because of cost and availability considerations. Cycling of units originally designed for base load operation typically requires modifications to the boiler, turbine, water treatment system, controls, large motors, piping systems, and other plant components.

Cycling operation increases boiler header and tube stress cycling. During a warm restart, the superheater and reheater tubing and headers will experience differential surface temperatures as compared to the interface surface at wall and roof penetration sealing points, which will remain near the steam saturation temperature. The headers will retract as temperatures decrease during a load reduction or shutdown “bottled” condition and they will expand as the temperatures increase during a restart. This differential expansion will increase the magnitude and number of stress cycles on the tube-to-header connections, particularly at the end points, where the differential movements will be greatest. A flexible header connection design is often necessary to accommodate this extra movement and prevent undue stresses from being transferred to the header and tube attachment points.

Determining the requirements for cycling operation requires analysis of the boiler, turbine, water treatment system, controls, large motors, piping systems, and other plant components. A boiler/turbine bypass startup system and control system modifications may be required to reduce unit startup costs and to minimize thermal stresses. A detailed study would be required on a unit-specific basis to determine the limitations and changes that would be required for cycling operation.

Other needed changes to accommodate cycling could include those associated with “winterizing” the unit for long shutdown periods. Modifications could include additional drains, unit heaters, heat tracing, and other measures, e.g., a new auxiliary boiler, to prevent freezing and delay in unit restart.

2.4 Expected Nitrogen Oxide (NO_X) and Carbon Monoxide (CO) Emissions

The formation of NO_X is determined by the interaction of chemical and physical processes occurring within the boiler. There are two primary forms of NO_X: *thermal* NO_X and *fuel* NO_X.

Due to the characteristically low nitrogen content of natural gas, NO_X formation through the fuel NO_X mechanism is normally insignificant. Therefore, the principal mechanism of NO_X formation in natural gas combustion is thermal NO_X, which results from the oxidation of nitrogen in the combustion air contained in the inlet gas in the high-temperature, post-flame region of the combustion zone.

The major factors influencing thermal NO_X formation are temperature, the concentration of oxygen in the inlet air, and residence time within the combustion zone. Low-NO_X burner (LNB) technology can affect thermal NO_X formation by regulating the distribution and mixing of the fuel and air to reduce flame temperatures and residence times at peak temperatures.

Several methods are available to effectively limit NO_X formation during combustion, as summarized below.

- Increase the size of the furnace
- Control peak flame temperatures below 2800°F
- Add flue gas recirculation to the combustion air to lower flame temperature
- Reduce excess air

The impact of heat input/furnace plan ratio on NO_X emissions is summarized in Table 2-1. This parameter becomes critical for boilers designed for bituminous fuel in determining the effectiveness of NO_X control.

Table 2-1. Defining Heat Input / Furnace Plan Area Ratio

Heat Input / Furnace Plan Area Ratio	Definition	Expected NO_X Emissions*	Expected CO Emissions
Less than 1.6	Typical for low thermal NO_X formation	≤0.15 lbs/MBtu	100 - 200 ppm
1.6 – 2.0	Typical for moderate thermal NO_X formation	0.15 – 0.20 lbs/MBtu	100 - 200 ppm

*Note: With OFA/SOFA and no flue gas recirculation (FGR).

2.5 Expected Carbon Dioxide (CO_2) Emissions

Natural gas firing offers a strategy to reduce CO_2 emissions. The CO_2 emission factor will vary depending on the carbon content and heating value of the fuel fired, but the typical CO_2 emission factor for natural gas is approximately 40% less than the coal emission factor.

2.6 Technology Overview

2.6.1 Low-NO_X Natural Gas Burners

LNBs limit NO_X formation by controlling both the stoichiometric and temperature profiles of the combustion flame in each burner flame envelope. This control is achieved with design features that regulate the aerodynamic distribution and mixing of the fuel and air, yielding reduced oxygen (O_2) in the primary combustion zone, reduced peak flame temperature, and reduced residence time at peak combustion temperatures. The combination of these techniques produces lower NO_X emissions during the combustion process.

NFPA 85 classifies igniters in three ways (Class 1, 2, and 3). Class 3 igniters typically are provided for natural gas conversions due to cost considerations.

2.6.2 Converting Cyclone Burners to Natural Gas Firing

The gas fuel burners/nozzles typically are composed of three flat spuds located in the existing secondary air dampers. The cyclone burner can be supplied with a manifold, having individual piping to each spud. The refractory can be removed for 100% natural gas operation but the studs could remain in place. Whether to remove the refractory studs is determined by the OEM's boiler assessment. Minor modifications might be required to the cyclone re-entrant throats/slag tap direction to facilitate the flue gas properly exit the cyclone burner.

2.6.3 Converting Tangentially Fired Burners to Natural Gas Firing

The gas fuel nozzles are composed of two spuds located in the existing coal compartments. Each new gas fuel compartment would feature two gas-spud elements and gas supply piping that will manifold together and terminate at a single butt-weld connection at the exterior of the windbox. A single flanged inlet pipe would protrude from the header through the windbox to connect to the gas supply flex hose. All air tips within the main windbox typically are replaced.

2.7 Flue Gas Recirculation

Flue gas recirculation (FGR) controls NO_X by recycling a portion of the flue gas from the economizer outlet and back into the primary combustion zone in the windbox. The recycled air lowers NO_X emissions by (1) lowering the combustion temperature; and (2) reducing the O_2 content in the primary flame zone. The amount of recirculation is based on flame stability requirements and is normally in the 15% range at 100% MCR to minimize NO_X formation and maintain proper tube metal temperatures and attemperation. However; in some cases the amount of FGR can be as high as 30%.

Our experience also suggests that the mixed flue gas/combustion air flow supplied to the windbox should be not lower than approximately 16% O_2 because lower O_2 content impacts flame stability and could promote the formation of excess CO and volatile organic compound (VOC) emissions.

An FGR system may also increase heat absorption in the convection pass, resulting in increased boiler tube temperatures and attemperation rates. Increased flue gas flow rates would be a concern regarding boiler tube-metal temperatures; however, lower excess combustion air with natural gas firing will tend to reduce the overall flue gas flow increase. In most cases steam temperatures and attemperation feedwater flows increase helping maintain design steam temperatures. Existing attemperators, valves, and piping often include design margins allowing these components to work on a gas converted boiler without modification.

NFPA 85 requires that an FGR system be provided with either the ratio of flue gas to air or to the oxygen content of the mixture. Oxygen analyzers typically are supplied downstream of the FGR mixing area in the windbox since duct space is limited for a flow measurement system. These analyzers will monitor the oxygen content of combustion air and alert the operator if oxygen is being overly diluted, which may cause the flames to become unstable.

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FGR increases hot reheat steam temperatures at control load (low-load/low maximum continuous rating [MCR]) improving superheat/reheat steam temperature control.

2.8 Selective Catalytic Reduction

In the event that NO_X cannot be adequately controlled with an LNB and FGR, it may be necessary to use a selective catalytic reduction (SCR) system. SCR is a process in which ammonia reacts with NO_X in the presence of a catalyst to reduce the NO_X to nitrogen and water. The catalyst enhances the reactions between NO_X and ammonia, according to the following reactions:

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$

$$4\ NO_2 + 8\ NH_3 + 2\ O_2 \rightarrow 6\ N_2 + 12\ H_2O$$

The location for this process is normally downstream of the economizer and upstream of the air heater. SCR technology can be applied at *full-scale*, which is an independent reactor vessel with inlet and outlet ducting or *in-line*, whereby the SCR uses the current ductwork, modified to expand the dimensions of the duct to hold the catalyst.

In-line SCR systems differ from full-scale SCR systems because they are installed within the existing flue gas flow path, as opposed to a separate reactor structure. Such SCR systems are usually installed to achieve +90% NO_X reduction for gas-fired units. Installation requires "ballooning" the ductwork to reduce the normal 60 feet per second (fps) flue gas velocities to the required 20- to 25-fps range. Thus, physical space must be available around the existing ductwork to accommodate the larger duct dimensions.

Static mixers typically are not installed in gas units as high ammonia slip of 5-10 ppm can be tolerated. An injection grid can be used to distribute reagent uniformly across the entire flue gas path.

We find that most existing SCR systems on coal-fired boilers can be reused when the unit is converted to gas firing without extensive modifications.

2.9 NFPA 85 Furnace Implosion Considerations

When boiler trips occur, flame collapse causes furnace negative pressure excursions. With gas firing, fuel cutoff is much faster than when firing coal, which may result in a change to the pressure excursion throughout the draft system.

A strict interpretation of NFPA 85 would require a furnace transient design of −35 in WC, which is often more negative than what the existing boilers, ducts, and precipitators were originally designed to handle.

NFPA 85 states:

> **"6.5.1.3.2.2* Negative Transient Design Pressure.** The negative transient design pressure shall be at least as negative as, but shall not be required to be more negative than, -8.7 kPa (-35 in. of water).

> Exception: If the test block capability of the induced draft fan at ambient temperature is less negative than -8.7 kPa (-35 in. of water), for example, -6.72 kPa (-27 in. of water), the negative transient design pressure shall be at least as negative as, but shall not be required to be more negative than, the test block capability of the induced draft fan."

However, NFPA 85 does allow the use of alternative design approaches as described below:

> "**1.2.3** This code shall not be used as a design handbook.
>
> **1.2.3.1** A designer capable of applying more complete and rigorous analysis to special or unusual problems shall have latitude in the development of such designs."

Reinforcing boilers, air heaters, ducts, and precipitators can be expensive and require long outages. For this reason, many plant owners have decided not to reinforce their furnaces to −35 in WC.

Some of the common transient conditions that cause the most problematic negative furnace and draft system pressures are described in Table 2-2.

Table 2-2. Common Transient Conditions to Evaluate

Transient Conditions	Description
1	Operating problems during fan startup and furnace purge – The ID fans can produce a higher pressure when handling cold air or cold flue gas than when operating with hot flue gas. Several plants have experienced high negative pressure under these conditions; however, the potential transients during start up of the fans and furnace purge will most likely be similar for natural gas as for coal firing.
2	Runaway ID fan at low load – This is a common case that is evaluated in transient studies and considers that at low load, the ID fan(s) increase in speed (or the inlet vanes open for constant-speed fans) due to a control system failure. This will cause a high negative furnace pressure that will result in a master fuel trip (MFT).
3	FD fan trip and MFT – A trip of the FD fans will cause the ID fan(s) to trip (except the last ID fan) and an MFT.
4	MFT based on turbine generator or other major problems.

The distributed control system (DCS) will require reprogramming to ensure that the natural gas conversion complies with the current NFPA 85 requirements and triple-redundant pressure transmitters are installed, which are auctioneered using a median-select methodology. In the control system, the furnace pressure signal and a feed-forward demand signal will be inputs to the furnace pressure control subsystem, which modulates the furnace pressure regulating control element to maintain a desired setpoint. A furnace pressure control protection system will be applied after an auto/manual transfer station to minimize furnace pressure excursions under both operating modes. The furnace pressure protection system will include a feed-forward override action that will be initiated by an MFT in anticipation of a furnace pressure excursion due to flame collapse, and will work in conjunction with logic to minimize furnace pressure excursions.

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2.10 Conceptual Design and Technical Considerations

The major equipment necessary to implement a coal to natural gas conversion may include:

- Utility gas supply
- Utility metering, regulating and custody station
- Natural gas burners and igniters
- Flame scanners and electronics
- Pressure reducing valve (PRV) station
- FGR fans, motors, and ductwork
- Foundations
- Natural gas distribution piping
- Vent piping
- Instrument air system modifications
- Scanner cooler air modifications

Additional design considerations that may be required include:

- Windbox modifications
- Cathodic protection system modifications
- Grounding system modifications
- FD and ID fan control modifications
- BMS, CCS, and DCS modifications
- Demolition and de-termination of coal and ash equipment
- Switchgear modifications
- Hazardous area reclassification and related upgrades
- Access galleries for operation and maintenance
- Freeze protection
- Plant heating system addition/modification

3. ECONOMIC CONSIDERATIONS

3.1 Capital Cost Estimates (CAPEX)

Project costs are estimated at various points in the project to obtain organizational resources, hire outside consultants, and obtain funding for the project. The amount of effort and the required accuracy of the project estimate depend on its purpose and the level of project development and assessed risks.

The majority of studies we have performed are screening efforts where AACE Class 4 estimates are prepared. Class 4 estimates have a project definition of 1% to 15%, and carry an accuracy range of −30% to +50%. This level of estimate is sufficient to determine the viability of the gas conversion project versus other alternatives (e.g., gas turbines, reciprocating internal combustion engine [RICE], and combined-cycle [CC]) and provides cost estimates that many organizations deem sufficient to fund more detailed study phases, secure project funding, or prepare a rate case.

Cost categories can vary depending on the size of the boiler, project location, season of implementation, outage duration, and numerous other project-specific criteria. Market demand and material pricing indexes can also impact the project cost. In addition, contracting strategy will also play a role in the total cost of the project.

Discussed below are several common cost categories to consider in developing the project cost estimate.

3.1.1 Direct Costs

Direct costs include all the equipment, materials and direct labor that are quantifiable and can be estimated for the project. A list of equipment typically required for gas conversion can be found in Section 2.10.

3.1.2 Project Direct and Construction Indirect Costs

These costs include:

- Mobilization/demobilization
- Subsistence/per diem
- Scaffolding
- Overtime
- Consumables
- Freight on equipment and material
- Sales tax
- Contractor G&A expenses
- Contractor profit

3.1.3 Project Indirect Costs

These costs include:

- Engineering, procurement, and project services
- Construction management
- Craft startup and commission support
- Startup spare parts
- Operator training

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- Owner costs, including:
  - Acceptance testing
  - Construction support
  - Operations and maintenance training
  - Engineering effort borne directly by the Owner during project execution

3.1.4 Financing Costs

The costs associated with financing the project must be included in the total project cost estimate. The more significant financial cost categories are:

- Contingency
- AFUDC
- Financing
- Escalation
- Insurance

3.2 Operating Costs

3.2.1 Fuel

Gas prices over the life of the boiler will likely be the single most significant cost variable to consider. Like coal, gas prices two, five, and twenty years in the future are an unknown. To forecast operating costs it will be necessary to make a prediction of gas prices for the project. Often, utilities have a Fuels Department that can assist in predicting gas prices.

3.2.2 Auxiliary Power

Auxiliary power consumption will be lower with the elimination of coal-handling and coal-preparation equipment, and discontinued use of ash-handling and flue gas desulfurization (FGD) systems. This can be a considerable amount of disconnected load, which can yield large savings and provide further justification for the conversion. Auxiliary power consumption is highly dependent on the existing operation and needs to be evaluated on a case-by-case basis.

Coal unloading equipment, such as railcar dumpers, barge unloaders, and conveyors will no longer be required. Similarly, reclaim equipment like dozers, stacker/reclaimers, and conveyors will be unnecessary.

Coal-preparation equipment, including pulverizers, also would not be needed in a natural gas fueled power plant.

The plant will no longer have to operate pneumatic blowers/exhausters, drag chain conveyors, sluicing pumps, or dewatering bins for ash handling.

3.2.3 Water

The amount of water required to operate a gas plant is less than that of a coal plant primarily due to the elimination of ash-handling systems and the treatment or disposal of contaminated water used in cleaning processes.

Potential areas to find savings in terms of water include:

- Boiler cooling systems if accompanied by changes in capacity factor
- Ash handling (i.e., sluicing)
- Boiler/APH cleaning
- Dust handling/control
- Wastewater treatment
- FGD systems

The amount of water reduction is dependent on the existing operation and must be examined on a case-by-case basis.

3.2.4 Operating Labor

The amount of labor required to operate a gas plant is less than that of a coal plant. Some common areas of labor-savings to examine include:

- Coal receiving and unloading, including rail and barge operations
- Coal storage and reclaiming
- Ash hauling and disposal
- Coal lab technician
- Coal equipment maintenance
- Ash handling system maintenance
- Custodial/Housekeeping
- Gate Security

The amount of operating labor reduction is dependent on the existing operation and must be examined on a case-by-case basis.

3.2.5 Maintenance Costs

When making a comparison of various projects, or evaluating options for a particular project, it is essential to consider the operating costs over the design life of the project.

Development of detailed maintenance costs could be performed where each piece of major equipment can be evaluated individually for planned services; however, unlike a steam turbine or a boiler, there are no comparable major service intervals for gas-firing equipment.

3.3 Total Evaluated Cost

There are many approaches to perform a financial evaluation, including Net Present Value (NPV), Internal Rate of Return (IRR), Payback Period, Return on Investment (ROI). The optimal approach for any project is often driven by organizational policy, accounting practices, or the requirements of lending institutions or insurers.

3.4 Contracting Strategy

There are various types of contracting strategies available for capital projects, including Multiple Lump Sum, Time and Material (T&M), Cost Plus, Guaranteed Maximum Price, Target Price, and Engineer, Procure and Construct (EPC). The best contracting approach is one that aligns with the organization's culture, project goals, risk tolerance, experience, and budget.

Though a thorough description of contracting strategies is beyond the scope of this paper, it is important to note that selection of an appropriate contracting strategy in the early stages of a project will produce more accurate cost estimates and better-quality project schedules.

4. SCHEDULE CONSIDERATIONS

On any major project, there are numerous aspects that can affect the project schedule. Table 4-1 identifies major project phases and approximate duration ranges experienced on recent projects. The information shown is intended to provide a sense of the calendar time necessary to perform a coal-to-natural gas conversion project.

Table 4-1. Major Project Activity Durations (Months)

Project Phase	Duration Range
Study phase	3 – 6
Execution phase:	
Engineering and design	2 – 6
Procurement and fabrication	6 – 15
Construction	3 – 6
Commissioning, startup, and performance testing	1 – 2
Overall	**12 – 24**

It is feasible that some of these activities could be performed in parallel, thereby shortening the overall project duration.

Procurement is highly variable depending on the equipment required for the conversion. For instance, FGR fans are often the longest-lead item and cannot be ordered until thermal modeling and sufficient engineering work have been undertaken. A project not requiring an FGR system may have a shorter overall project schedule.

Many construction activities can be performed while the unit is still firing coal. Some of the common construction activities that can take place pre-outage include:

- Install utility gas line and M&R station
- Install main gas header piping to unit
- Construct foundations
- Install PRV stations
- Install FGR fans and fan motors
- Install FGR ductwork (partial)
- Install in-unit gas supply and vent piping
- Civil improvements
- Install gas detection and other instrumentation

The remaining installation activities can take place during a unit outage of as little as one month for a small boiler with one or two burners, or three to four months for a large boiler with twenty or more burners.

Some activities can be performed only during certain seasons. For example, underground gas piping cannot be installed during the extreme winter months in the northern areas. Also, many utilities cannot or choose not to take a unit outage during peak energy demand months.

Converting multiple units concurrently can also provide a savings in project schedule and total project cost.

Unit hardening for cycling operation is a highly variable undertaking and can have significant impact on the overall project schedule, outage duration, and project cost. If required, the project schedule needs to account for cycling-related upgrades as described in Section 2.3.

5. CASE STUDY PLANT

The case study plant had three boilers that were converted from coal to natural gas firing; Boilers A, B, and C. Boilers A and B was firing coal and Boiler C was firing a blend of coal and woody biomass.

Boilers A and B are similar, with four front wall-fired coal burners, tubular air heaters, mechanical dust collectors, and balanced-draft furnaces. Each boiler is rated at 110,000 lbs/hr main steam. Boiler C is coal stoker-fired with a tubular air heater, mechanical dust collector, and balanced-draft furnace rated at 225,000 lbs/hr main steam. The boilers have and will continue to operate in a load-following mode for the facility's process steam needs.

A single burner design feasible for all three of the boilers was developed, which limited the amount of spare parts for the plant. The burners were installed in the two lower existing burner openings of Boilers A and B. As the full amount of combustion air required for gas firing could not be delivered through the two burners, the upper two existing burner openings were utilized to provide the remainder of required combustion air. The upper two burners were replaced with

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shroud assemblies, i.e., OFA, to control the amount of air flow through the openings relative to unit load.

To avoid pressure part modifications on Boiler C, four new natural gas burners were installed in the four existing biomass chute openings. A new windbox with additional duct required to provide combustion air to the new windbox was provided.

A new natural gas line was installed from the gas supplier's new M&R station to a common PRV station, and then on to the boiler fronts. Structural steel modifications to reinforce an existing building roof to support the new PRV station were made. This location of the PRV station provided a well-ventilated, Class I, Division 2 environment. Also, the existing DCS was modified, including new BMS and MFT cabinets and associated programming.

The execution phase spanned just 16 months, concluding with three consecutive outages between July and December 2014. This was one year ahead of the January 31, 2016, Industrial Boiler Maximum Achievable Control Technology (MACT) deadline.

Figure 5-1 shows before and after photographs of the boiler conversion.

Figure 5-1. Before and After Boiler Conversion

Before

After

A summary the boiler performance and emissions is provided in Table 5-1.

Table 5-1. Guarantee Boiler Performance at 100% MCR

Parameter	Unit	Boiler A	Boiler B	Boiler C
Average NO_X emission rate	(lb/MBtu)	0.14	0.14	0.14
Average CO emission rate	ppm volume dry @ 3% O_2	≤200	≤200	≤200
Superheater steam flow	lbs/hr	110,000	110,000	225,000
Superheat steam temperature	°F	700 (±50)	700 (±50)	930 (±30)
Boiler efficiency per PTC 4	%	81.54	81.54	82.21

6. KEY RECOMMENDATIONS FOR SUCCESSFUL PROJECT

6.1 Project Development and Implementation

- Observe the accuracy range of the project estimate. Fund the project based on the appropriate estimate class and contingency level.
- Decide a contracting strategy up front to improve the accuracy of the estimate (refer to Section 3.4). This also impacts the project duration and schedule.
- Perform boiler thermal and transient analyses. Among other aspects, the amount (and cost) of fuel, heat rate, and extent of pressure part modifications can vary widely based on the results of this effort.
- Plan the fuel supply and vent piping corridors early in your project. This is especially important of underground gas lines, where disturbed soil will necessitate special permitting or environmental impact studies, either of which can seriously impact the project cost/schedule.
- Labor wage rates must be local to the project site and can vary widely on geography, fluctuating construction market conditions, union/non-union or open shop, and seasonality.

6.2 Engineering and Design

- Gather existing equipment drawings and system documentation early in the process. These will be essential to the project's progress and technical soundness.
- Identify the location and condition of the gas being supplied by your gas supplier.
- Obtain a fuel analysis for all of the possible natural gases being considered.
- Decide if individual gas meters are needed for each boiler or on each igniter and boiler train, or if the gas suppliers' commercial meter will be sufficient for records purposes and to comply with permit requirements.
- Avoid onerous requirements that will be difficult or not possible for suppliers to provide. Specify standard equipment where possible.
- Furnace implosion considerations should be addressed very early in the engineering and design phase.
- Perform a Hazard and Operability Study (HAZOP)
- Provide adequate isolation, e.g., double block and bleed valves, to major redundant components in the PRV skid design to facilitate maintenance, startup and commissioning.

6.3 Project Startup

- Have specialty and brass tools available.
- Use an ultra-probe to identify leaking valves.
- Have detailed procedures and system-specific meetings before a system startup.
- Burner/igniter timers may need adjustment to allow for proper tuning of flame scanner(s).

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