Natural Gas Co-Firing Memo

FINAL

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Purpose

This report summarizes the effects, feasibility, required modifications, and preliminary cost and performance associated with converting coal-fired boilers to co-fire natural gas. The primary purpose of investigating co-firing technology options is to understand the potential for CO_2 emission reductions at coal-fired units.

Co-firing Background

When evaluating the prospect of converting a coal-fired boiler to co-fire both coal and natural gas, there are a number of important factors that must be independently evaluated. These include the existing natural gas system infrastructure, required burner level modifications, combustion system configuration, and boiler performance impacts.

Furthermore, several variables associated with an existing coal plant affect the expected performance impacts and required modifications due to co-firing natural gas. These include the type of coal that is currently being burned, the type of ignition/warm-up fuel that is currently being used, the OEM and type of boiler (tangential, wall fired, cyclone, etc.), the boiler capacity (measured in steam flow rate or MW), the existence of any backend emissions equipment (FGR, FGD, etc.), and the type and number of coal burners.

This interim report will provide a brief description of co-firing, a summary of typical modifications required, a discussion of its applicability in various types and sizes of boilers, the expected effects on boiler performance, and high-level cost estimates for co-firing retrofit at three unique boiler facilities.

Natural gas co-firing is possible for all types and sizes of boilers, and the required modifications, considerations, and limitations are generally the same for all types of boilers. However, boiler thermal modeling, a review of compliance with NFPA 85 requirements, an analysis of the combustion air system, and other engineering analyses are required to determine what modifications will be required for each specific application.

Existing Coal Boiler Fleet

Table 1 below quantifies the number of different types and sizes of coal-fired boilers that are currently operating in the U.S. This report focuses on wall-fired and tangentially-fired boilers as these are the most common types of boilers.

Table 1 – Existing U.S. Coal Boiler Fleet Details[1]

Boiler Type	# of Units	Average Unit Size (Annual Load/Annual Hours)[2]			
		25-100 MW[3]	100-250 MW	250-500 MW	500 MW+
Cell burner boiler	21	0	0	5	16
Circulating fluidized bed boiler	39	4	5	30	0
Cyclone boiler	29	3	3	18	3
Dry bottom turbo-fired boiler	11	0	6	5	0
Dry bottom wall-fired boiler	199	17	40	76	50
Other boiler	1	0	0	1	0
Stoker	5	0	0	5	0
Tangentially-fired	188	11	39	73	55
Wet bottom wall-fired boiler	12	0	12	0	0
Bubbling fluidized bed boiler	1	1	0	0	0
Total	**506**	**36**	**105**	**213**	**124**

Notes:

1. Per EPA Air Market Database as of November 2021.
2. Unit size was approximated by taking total annual load/annual hours, and therefore, this is annual average size rather than design size.
3. For the purpose of this report, only boiler sizes greater than 25 MW will be assessed.

Co-Firing Description

Natural gas co-firing is the ability of a boiler to simultaneously fire a combination of coal and natural gas. The percentage of co-firing is defined based on the percent of the full load heat input provided by natural gas. For units that use natural gas for boiler light off, initial warming, and low load operation, co-firing capability is already present but may not be used for normal load generation. In comparison, dual-fuel firing capability is the ability to independently fire either coal or natural gas and achieve full load with either fuel. Lastly, a coal-to-gas (CTG) conversion involves modifying a unit to only fire 100% natural gas.

Recent projects that have involved modifying an existing coal-fired boiler to fire natural gas have usually implemented either a complete CTG conversion, or dual fuel firing capability. However, in some cases, it may not be possible to achieve 100% load capability on natural gas alone. Reasons for this may include: the supply of natural gas in the area is insufficient and it is infeasible to increase the delivered capacity, the gas supply may be curtailed at times, boiler output is reduced due to gas firing impacts on boiler thermal performance, etc.

One of the primary benefits of co-firing is emissions reduction. In a co-firing environment, the original emissions control equipment must remain operational to process the remaining coal-based pollutants such as mercury, SO_2, and particulate which continue to be generated at lower concentrations roughly proportional to the percent co-firing. CO_2 stack emissions are reduced at a rate scaled to the percent reduction associated with 100% natural gas firing. To illustrate, CO_2 stack emissions per kW-hr at 100% natural gas-fired boiler power plants are approximately 40% lower than comparable coal-fired units. Therefore, the reduction in CO_2 emissions due to co-firing is between 0% to 40%, in approximate proportion to the percent of co-firing (i.e., CO_2 emissions are reduced approximately 4% for every additional 10% of co-firing). NO_x emissions are also typically reduced but the magnitude of the reduction is dependent on the combustion system modifications that are implemented.

Operating costs can potentially be reduced when co-firing natural gas due to labor savings associated with the following activities (however, this may be minimal depending on the quantity of co-firing):

- 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
- Emission control technology operating costs (chemicals, power, etc.) associated with lower emission concentrations

While some of these costs are variable, others are fixed, and the savings would be dependent on the extent to which permanent labor reductions can be implemented. It is worth noting that the fuel cost associated with co-firing is variable based on the fluctuations in natural gas and coal pricing.

Lastly, another benefit of co-firing is the potential for improved low load capability. For coal firing, the “turn-down ratio” is dependent on the quantity and turn-down capabilities of the pulverizers and the turn-down capabilities of all other associated balance of plant equipment, such as the fans and boiler feed pumps. Most conventional coal-fired boilers were designed with limited turndown range, with a typical minimum load around 30% of MCR rating. For 100% gas firing, the “turn-down ratio” is no longer affected by the coal pulverizers and can potentially be lower; however, this ratio is still dependent on the turn-down capabilities of all other associated balance of plant equipment. Minimum loads can be closer to 20% of MCR rating when firing 100% natural gas. The potentially enhanced “turn-down ratio” capability with natural gas makes

extended operation at low-load conditions significantly easier to maintain, either through the use of the natural gas ignitors, natural gas main burners, or a combination of the two.

Co-Firing Modifications

There are several co-firing technologies that can be implemented on a unit. They are broken down into two categories, supplemental and reburn. Supplemental co-firing describes a configuration wherein the gas burners are located within the burner belt. Reburn co-firing describes a configuration wherein the gas burners are located above the burner belt, thereby effectively "reburning" the combustion products as they rise up from the burner zone. Reburn technologies were initially developed to provide NO_x reduction but provide the co-benefit of CO_2 and other pollutant reductions as discussed above. Supplemental co-firing and reburn technologies include the following:

- Supplemental Gas Co-firing
- Coal/Gas Dual Fuel Burners
- Gas Reburning (RB)
- Fuel Lean Gas Reburning (FLGR)
- Advanced Gas Reburning (AGR)
- Amine Enhanced Fuel Lean Gas Reburn (AEFLGR)

The economic benefits, experience, number of applications, and commercial availability varies between these natural gas co-firing technologies. The largest number of applications and the longest operating times involve the gas reburning (RB) and supplemental gas co-firing technologies. However, the implementation of all reburning technologies has decreased in recent years due to the decrease in operating coal plants and the feasibility of supplemental gas co-firing. The table below details some of the expected emission reductions and associated costs with those reductions.

Table 2 – Summary of Emissions and Economics Potential for Gas Co-firing Technologies

Technology	Gas Heat Input (%)	Range NO_x Reductions (%)	Range CO_2 Reductions (%)	Other Emissions Benefits
Reburn	12-20	50-60	4-8	Reduced SO_2
FLGR	6-7	30-37	2-3	Reduced SO_2
AGR	12-15	65-70	4-6	Reduced SO_2
AEFLGR	6-7	45-50	2-3	Reduced SO_2
Supplemental gas co-firing[1]	2-20	10-15	1-8	Reduced SO_2, PM, opacity
Dual fuel firing	0-100	Unit specific	0-40	Reduced SO_2, PM, opacity

Notes:
1. Gas heat input greater than 20% (and up to 100% with modifications) is possible using warm-up guns.

While all of these reburning options can reduce NO_x emissions, the focus of this memo is CO_2 emission reductions, therefore, supplemental natural gas co-firing will be the focus of this evaluation.

Range of Co-Firing

For most plants, 100% natural gas firing is possible; however, for some plants, the range of co-firing may be limited based on a variety of factors. This can include the desired type and quantity of emission reductions, the availability of natural gas supply to the plant, regulatory requirements for the location of the plant, and effect on boiler performance.

Availability of Natural Gas

When considering a co-firing conversion, it is an advantage if the plant already has natural gas available on-site, or is located close to an existing natural gas supply line with adequate surplus capacity, rather than one located many miles away or that is at or near capacity. Natural gas can also potentially be stored on-site, typically as Liquified Natural Gas (LNG), but this storage is not typically included for co-firing purposes or for plants designed to burn natural gas because it is unnecessary and costly.

For the purpose of this report, it is assumed that the facilities either have natural gas on-site or have easy access to a natural gas supply line. For plants that do not have this accessibility to natural gas, further analysis and information would be required to assess the feasibility of bringing a supply of natural gas to the facility. Natural gas infrastructure and supply to the site is not included in this analysis, and the cost information.

Typical Scope of Work

The scope of work associated with implementing natural gas co-firing is dependent on the existing gas firing capability of the unit, boiler design, type of combustion air equipment installed, etc. Modifications that may be required as part of a natural gas co-firing retrofit project are summarized below:

- Retrofit of a new or modified natural gas supply system (on-site), including a metering and regulating skid, flow and pressure regulating skids, safety shut-off valves, automated gas venting system, gas fired or dual fuel burners, gas fired ignitors, and control system modifications.
- Modifications to the boiler, such as upgraded waterwall tube materials, increased or decreased steam section surface area, installation of a flue gas recirculation (FGR) system to maintain steam temperatures and gross unit output, installation of an overfire air (OFA) system and pressure part modifications to install new gas burners. A thermal computer model analysis of the boiler is required to verify expected performance and to determine if these modifications are required.

- Modifications to the ID fan controls and hardware or implementation of time-delayed tripping of the fuel gas valves to comply with NFPA 85 requirements to mitigate potentially more severe and rapid furnace pressure transients subsequent to master fuel trips. Such steps are typically adequate to avoid the need for boiler reinforcement.
- Upgrades to the forced draft (FD) fans and FD fan motors to increase capacity or installation of a cross tie duct from the primary air (PA) fan discharge to the FD fan discharge to increase combustion air supply. This is most likely not required for relatively low co-firing rates of 20% or less but may become necessary at co-firing rates higher than 20%.
- Upgrades to the air heater to guarantee thermal performance during co-firing.
- Modifications to existing balance of plant equipment to ensure lower load operation can be accommodated if part of the design.

In general, the potential modifications listed above are relevant for most types and sizes of boilers. The following differences among types of boilers may affect cost and performance and will differ case-by-case:

- The modifications/installation of the gas burner system differ slightly depending on the type of boiler, number and arrangement of burners, and the available space in the burner areas.
- Smaller units (25 – 100 MW) may not have a PA fan (primary air also supplied by the FD fan) or the PA fan may be in series with the FD fan(s). FD fan modifications are not required for such units since the FD fans are sized to supply 100% of the combustion air flow.

Natural Gas System

A new or modified natural gas supply system will be installed to supply natural gas to the boiler for combustion. This new system typically includes a fuel gas metering and regulating station, pressure reducing and flow control skids, safety shutoff valves, main gas piping, ignitor gas piping, automated vent piping, and natural gas burners and ignitors. Natural gas can also potentially be stored on-site, typically as Liquified Natural Gas (LNG), but this storage is not typically included for co-firing purposes or for plants designed to burn natural gas because it is unnecessary and costly.

Effect on Plant Performance

Supplemental co-firing typically reduces the slagging and fouling conditions associated with coal combustion which improves boiler cleanliness, and which should tend to increase heat absorption. However, because gas flames are less luminous and have lower peak flame temperatures than coal flames, combustion-zone radiation rates to the furnace walls tend to be lower resulting in elevated furnace exit gas temperature (FEGT). This can cause higher tube-metal temperatures. Further, achieving design steam temperatures and full boiler output can be difficult for a boiler originally designed to burn coal. In some

cases, steam temperature derates are seen due to lower flue gas flow rate and rate of heat transfer in the convection pass.

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. Convection pass modifications can be implemented as a cost-effective approach to maintain desired steam temperatures. However, it is expected that flue gas recirculation may be needed if lower emissions when co-firing are required and to improve boiler turndown control.

As stated previously, factors such as the type and size of the boiler, number and type of burners, the quality of coal and natural gas, etc., can have a significant effect on the expected performance of the boiler when converted to co-fire natural gas. However, in general, the overall effect on performance is consistent amongst the various factors, and the expected performance effects detailed below are typical for all types and sizes of boilers.

The following changes in performance are typical when converting to co-firing. The degree to which they occur is dependent on the percent co-firing implemented:

- 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.
- Dry air requirements to fully combust natural gas fuels increase over coal, but the required amount of excess air decreases. Consequently, combustion air and flue gas flowrates generally decrease when co-firing.
- Heating surface absorption effectiveness increases with co-firing due to lower amounts of ash in the fuel that otherwise 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. However, this is offset somewhat by a decrease in flue gas flowrate.
- Total boiler efficiency losses increase compared to coal firing. Natural gas contains significantly more hydrogen than coal. This increases the loss due to vaporization of the water in the flue gas that is formed during the combustion of hydrogen in fuel. This increased loss is offset somewhat by a decrease in the dry flue gas loss, reduction of the fuel moisture loss, and reduction of the unburned carbon loss.

- Attemperator flowrates typically increase. This is due to higher steam temperatures as a result of the higher FEGT and increased surface absorption effectiveness. Conversely, steam temperatures may decrease in boilers where superheating occurs primarily in the convective pass.
- Tube metal temperatures may increase due to higher steam and flue gas temperatures. This may require upgrading pressure part materials if metal temperatures are above permissible limits.

Boiler Efficiency

Compared to coal, natural gas contains a large fraction of hydrogen (approximately 24% by weight). As discussed above, converting a boiler to co-firing will decrease boiler efficiency due to the increased hydrogen in fuel loss.

The dry flue gas loss typically decreases due to the lower gas temperature and quantity of flue gas leaving the air heater. There is also no fuel moisture loss with natural gas, as the fuel does not 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 there is no residual ash when burning natural gas.

The net impact on boiler efficiency due to co-firing is a slight decrease. The magnitude of the decrease is a function of baseline boiler performance, fuel properties, unburned carbon loss, and the percent co-firing implemented. A higher percentage of co-firing increases the hydrogen in fuel loss and decreases other losses associated with coal firing. For 20% co-firing, approximately a 1% to 2% reduction in boiler efficiency can be expected. In comparison, firing 100% gas can decrease boiler efficiency by up to approximately 5%. Therefore, co-firing rates between 20% and 100% are expected to reduce boiler efficiency within a 1% to 5% range.

Overall Heat Rate Impact

Heat rate is the ratio of cycle heat input rate divided by generation. “Unit” heat rate reflects the heat input to the boiler and is, therefore, impacted by changes in boiler efficiency. “Turbine” heat rate reflects the heat input to the turbine cycle and is independent of boiler efficiency.

“Net” heat rate is based on the net turbine power output, whereas “gross” heat rate is based on gross turbine power output. The difference between net turbine power output and gross turbine power output is the auxiliary power consumption. The values used to calculate auxiliary power consumption vary depending on whether one is defining net turbine heat rate or net unit heat rate, and whether motor or turbine drive boiler feed pumps are used.

The heat rates that are used to define unit performance include, Gross Turbine Heat Rate (GTHR), Net Turbine Heat Rate (NTHR), and Net Unit Heat Rate (NUHR). Technologies that change heat input to the turbine cycle, or turbine output impact all these heat rates. Technologies that impact boiler efficiency and total plant auxiliary power consumption impact only Net Unit Heat Rate.

Co-firing can impact all of the heat rate primary inputs:

- If steam temperatures are reduced, this lowers generator output and increases all heat rates.
- If auxiliary power is reduced, this lowers Net Unit Heat Rate
- If boiler efficiency is reduced, this increases Net Unit Heat Rate

As previously discussed, steam temperatures may increase or decrease depending on the boiler design. Further, boiler efficiency is expected to decrease between 1% to 5%. Lastly, since co-firing reduces coal consumption, auxiliary power demand tends to decrease due to the reduced power consumption of the pulverizers, PA fans and ID fans. However, since the backend equipment such as precipitators, FGD equipment, baghouses, etc., must remain in service, the auxiliary power associated with this equipment remains largely intact.

Overall, the net effect on heat rate must be evaluated specifically for each application. If boiler output and generation are not affected, then gross and net turbine heat rates are unchanged. Again, this is dependent on whether steam temperature reductions are incurred due to co-firing. Net Unit Heat Rate is more likely to be impacted due to boiler efficiency and auxiliary power demand reductions. Typically, the NUHR will increase because the impact on boiler efficiency and steam temperatures will have a larger effect than the impact on auxiliary power demand reduction, but since these are counteractive impacts, the net effect on NUHR can vary within approximately +/-2%. The main factors that dictate the effect on NUHR are the amount of desired co-firing, the amount of excess air required for coal and gas firing, the reduction in plant auxiliary power, and the effect on boiler efficiency, and this expected NUHR effect is typically determined during detailed engineering.

Effect on Emissions

Converting to co-firing can significantly affect the emissions from the unit, and an analysis of all expected emissions should be performed to determine if any modifications are required.

Carbon Dioxide (CO_2)

Co-firing results in a reduction in CO_2 emissions. The reduction occurs at a rate scaled to the percent reduction associated with 100% natural gas firing. The table below shows the overall CO_2 reduction based

on the range of co-firing. The typical maximum amount of CO_2 reduction is 40% when firing 100% natural gas.

Table 3. Expected Carbon Dioxide (CO_2) Emissions for Co-Firing

% Coal Firing	% Gas Co-Firing	Boiler Efficiency[1]	CO_2 Emission Coal Firing Scaled	CO2 Emission Gas Firing Scaled[2]	Overall CO_2 Emission Scaled	% CO_2 Reduction
100	0	0.89	100.0	0.0	100	0
90	10	0.885	90.5	5.7	96.2	3.8
80	20	0.88	80.9	11.5	92.4	7.6
70	30	0.875	71.2	17.3	88.5	11.5
60	40	0.87	61.4	23.2	84.6	15.4
50	50	0.865	51.4	29.1	80.6	19.4
40	60	0.86	41.4	35.2	76.6	23.4
30	70	0.855	31.2	41.3	72.5	27.5
20	80	0.85	20.9	47.4	68.4	31.6
10	90	0.845	10.5	53.7	64.2	35.8
0	100	0.84	0.0	60.0	60.0	40.0

Notes:

1. Boiler efficiency typically decreases by 5% when converted to 100% natural gas (final row in table). 89% (0.89) was selected as a typical full load boiler efficiency value based on past experience, and values between 0.89 and 0.84 were based on linear interpolation.
2. CO_2 stack emissions per kW-hr at 100% natural gas-fired boiler power plants are approximately 40% lower than comparable 100% coal-fired units. Therefore, 60% CO_2 emissions were assumed for the 100% gas firing case (final row in table), and values between 0 and 60% were scaled based on the co-firing rate and difference in boiler efficiency compared to the 100% natural gas case.

Nitrogen Oxide (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. A properly designed gas fired combustion system with good NO_x control reduces the peak flame temperature of the primary combustion zone thereby reducing the thermal NO_x formation.

Effects on NO_x emission rates are dependent on the existing rates and the following factors for each unit: the type of combustion system in-place, what existing NOx equipment is already installed/implemented (such as Low NOx burners and OFA systems), what type of coal is being burned, if there is an FGR or not, and other factors. Due to these factors, it is not feasible to quantify the estimated effects on NO_x emissions

for a typical unit. However, supplemental co-firing with existing gas ignitors can reduce NO_x emissions by 10-15% assuming a gas heat input of between 2-20%. For larger ranges (>20%) of co-firing when burners are installed or modified, typically, Low NOx burners are utilized, which typically control NOx emissions to 0.15 lb/MMBtu. For the purpose of this report, it is assumed that no additional NO_x reductions are required, as the focus of this memo is on CO_2 reductions; however, if it is estimated that NO_x emissions need to be reduced further, additional modifications could be implemented. These methods include reducing excess air fired, utilizing Low-NOx burners, and installing an overfire air (OFA) or separate overfire air (SOFA) system, flue gas recirculation system, or selective catalytic or non-catalytic reduction (SCR or SNCR) system.

Carbon Monoxide (CO)

A boiler's CO emissions are an indication of incomplete combustion of the fuel due to inadequate mixing or insufficient oxygen (O_2) content. Excess air, windbox damper and burner tilt positions, boiler load, furnace design, fuel type, staging of the combustion process, and air in-leakage can all affect CO emission levels. CO emissions can increase rapidly within a relatively small operating range and each unit behaves slightly different. Gas reburn technologies can increase CO emissions due to the staged combustion process that is used. Supplemental co-firing and co-firing with dual fuel burners typically do not impact CO emissions but may depending on the chosen elevations and arrangements of the gas fire burners.

Sulfur Dioxide (SO_2)

Natural gas contains no sulfur; therefore, co-firing results in a reduction in SO_2 emissions. The reduction of SO_2 is proportional to the amount of co-firing (i.e., SO_2 emissions are reduced by 100% when 100% natural gas is fired).

Volatile Organic Compounds (VOCs)

Co-firing can result in an increase in VOC emissions.

Particulate Emissions

Natural gas contains no ash or particulates; therefore, co-firing results in a reduction in particulate emissions. The reduction of particulates is proportional to the amount of co-firing (i.e., particulate emissions are reduced by 100% when 100% natural gas is fired).

Mercury and Acid Gases

There is no mercury or chloride in natural gas; therefore, co-firing results in a reduction in these emissions. Similar to SO_2 emissions, the reduction of mercury and chlorine is proportional to the amount of co-firing (i.e., emissions are reduced by 100% when 100% natural gas is fired).

Capital Cost Scenarios

There are several modifications that can be done to an existing coal unit to achieve additional gas co-firing capabilities; these are summarized in Table 4 with their corresponding performance capabilities.

Table 4. Natural Gas Co-Firing Options

Option	Modification	Existing Heat Input from Gas Firing [1]	Future Heat Input from Gas Co-Firing [1]	CO_2 Reduction	Retrofit Considerations
1	Increase gas heat input with existing gas ignitors	0% to 15%	10% - 20%	3.8% - 7.6%	Only applicable for units with existing gas ignitors.
2	Convert existing oil ignitors to new gas ignitors	N/A	10% - 20%	3.8% - 7.6%	Only applicable for units with existing oil ignitors.
3	Increase gas heat input for existing warm-up guns	15% - 40%	20% - 100%	1.9% - 34.3%	Only applicable for units with existing warm-up guns. If a coal unit has no gas burners but existing heat input is greater than 15%, it can be assumed that warm-up guns are installed. Range of co-firing limited on quantity/design/capability of warm-up guns.
4	Convert existing coal burners to dual fuel burners	0%	10% - 100%	3.8% - 40%	Applicable to the majority of tangential and wall-fired coal-fired units. May be limited based on available space in the windbox / burner area or design of coal burners.
5	Install new gas burners	0%	10% - 100%	3.8% - 40%	Applicable to the majority of tangential and wall-fired coal-fired units. May be limited based on available space in the windbox / burner area.

Notes:
1 – Gas Co-Firing Range values are design (hourly) co-firing capacities for the unit.

As can be seen in the table above, there are several options that can achieve a low range of co-firing with minor modifications, as well as more significant modifications which can achieve a much higher percentage of co-firing, up to 100% gas firing. Table 5 below provides estimated capital and operating costs for ranges of co-firing modifications, based on the size of the unit.

Table 5. Natural Gas Co-Firing Cost Summary

Scenario Description	Gas Co-Firing Range (% or Heat Input)[1]	CO_2 Reduction (% of Emissions)	Project Capital Cost [2, 3, 4]
Partial Co-Firing with New/Modified Igniters (Option 1 and 2)	10% - 20%	3.8% - 7.6%	$500,000 + $1,540 / MW
Co-Firing with Modified Gas Warm-up Guns and/or Igniters (Option 3)	20% - 100%	1.9% - 34.3%	$46,361 / MW
Co-Firing with New/Modified Burners and/or Igniters (Option 4 and 5)	20% - 100%	3.8% - 40%	$52,200 / MW
Co-Firing with New/Modified Burners/Warm-up Guns and/or Igniters plus Convection Heating Surface Change (Option 3, 4, and 5) [5]	75% - 100%	29.5% - 40%	$78,700 / MW

Notes:
1 – Gas Co-Firing Range values are design (hourly) co-firing capacities for the unit.
2 – Project Costs are overnight total project costs, including all project indirects. No upstream natural gas equipment or modifications are included in these costs. Values are provided on a per MW basis for all options.
3 – The S&L in-house database of co-firing project costs were converted to 2021 dollars based on an escalation factor of 2.5% based on the industry trends over the last ten years (2010 – 2020) excluding the current market conditions.
4 – Costs for each option are representative of typical new equipment and modifications, including a new natural gas supply system, new burners/ignitors, control system modifications, and fan modifications. Potential larger modifications such as FGR or OFA addition, upgrades to waterwall tube materials, or modifications to existing balance of plant equipment to ensure low load operation are not included in these costs.
5 – If the unit is expected to experience a large derate in heat rate or steam temperature, the convective heating surface area modifications, as described previously in this report, should be included. These modifications are typically only required for units that have investigated co-firing ranges above 75% and are larger than 500 MW. Based on the co-firing / conversion studies that S&L has been involved in approximately 30% of units larger than 500 MW required these modifications.

Fixed O&M costs can potentially decrease when firing less coal due to less frequent maintenance required, reduced coal handling on-site, and an overall reduction in auxiliary power. With a reduction in coal consumption, coal yard equipment O&M will reduce. Costs associated with coal delivery, receiving, and reclaiming is expected to be reduced proportionally to the reduced rate of coal firing; this variable cost is dependent on the current coal market and labor rates. Auxiliary power consumption is also estimated to be reduced proportionally to the rate of coal co-firing since the equipment operating time is directly tied to the coal throughput. Similarly, it is estimated that the frequency of major coal yard maintenance projects such as crusher rebuilds, belt replacement, gearbox rebuild etc. will be reduced proportionally to the rate of coal cofiring due to reduction in operating time and equipment wear and tear. However, preventative maintenance measures consisting of daily, weekly and monthly checks would be expected to continue in a similar fashion regardless of the cofiring rate. Consumables (e.g. conveyor gearbox oil replacement) are not expected to significantly reduce since these are generally maintained on time intervals rather than operating hours. When evaluating cost reduction associated with the coal handling system reduced capacity, it is suggested that station specific operating/maintenance information be evaluated on a case by case basis and adjusted accordingly based on the anticipated co-firing rate and current market conditions. Lastly, it should be noted that it is also common for plants to maintain operation of one coal pulverizer at all

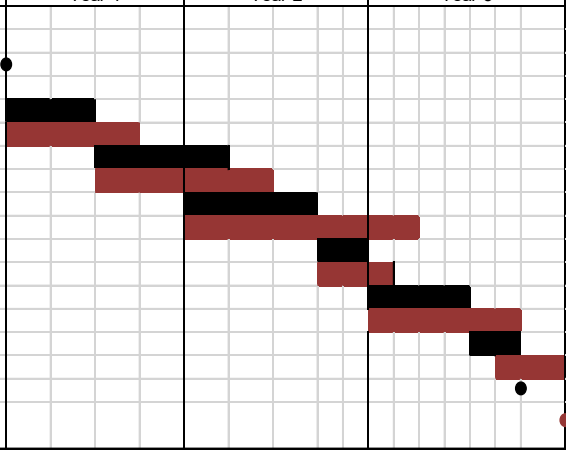
times, which equates to maintaining several coal burners in continuous service. Therefore, if this is true for a certain plant, coal handling equipment will be required to operate continuously and therefore have no effect on fixed O&M costs.

Variable O&M cost effects are highly dependent on the current costs of coal and natural gas for power. Typically, the cost in USD/MMBtu is higher for natural gas, so the variable O&M costs are expected to increase. If higher percentages of natural gas co-firing are pursued, the ratio of coal and natural gas firing can be adjusted based on the current market to find the most cost-effective fuel firing operation.

Therefore, it is expected that fixed O&M costs and non-fuel variable O&M costs will remain roughly the same for all of the co-firing scenarios considered.

Schedule

The following figure identifies major project phases and approximate duration ranges experienced for a coal boiler co-firing conversion. This applies to scenarios 2 through 5 from Table 5. Scenario 1 can typically be done during any major outage or overhaul and requires minimal engineering and design. All of the modifications for which costs were provided are similar to standard maintenance activities, and no long-term delays or schedule uncertainties are expected.

Figure 1. Co-Firing Conversion Project Schedule

No.	Description	Baseline Duration	Extended Duration
1	Decision to Proceed with Co-firing Conversion	Milestone	Milestone
2	Conceptual Studies/Design Basis	24 weeks	32 weeks
3	Specifications/Awards	24 weeks	32 weeks
4	Detailed Engineering	32 weeks	56 weeks
5	Site Work/Mobilization	12 weeks	16 weeks
6	Construction	16 weeks	24 weeks
7	Startup and Testing	9 weeks	12 weeks
8	Commercial Operation	Milestone (140 weeks from project start)	Milestone (156 weeks from project start)