# FINAL DRAFT NATURAL GAS CONVERSION STUDY

## E. W. Brown Station Units 1, 2, and 3

**B&V PROJECT NO. 194373**



**PREPARED FOR**

Louisville Gas & Electric and KU Utilities Company

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# Acronym List

| | |
|---|---|
| AQC | Air Quality Control |
| AQCS | Air Quality Control System |
| ASME | American Society of Mechanical Engineers |
| BMC | Boiler Modulating Control |
| BMS | Burner Management System |
| DC | Direct Costs |
| DCS | Distributed Control System |
| DIC | Direct Installation Costs |
| EA | Excess Air |
| EPC | Engineering, Procurement, and Construction |
| EPRI | Electric Power Research Institute |
| ESP | Electrostatic Precipitator |
| FD | Forced Draft |
| FGD | Flue Gas Desulfurization |
| ft/min | Feet per Minute |
| $H_2SO_4$ | Sulfuric Acid |
| HP | High-Pressure |
| I/O | Input/Output |
| IC | Indirect Costs |
| ID | Induced Draft |
| IR/UV | Infrared/Ultraviolet |
| LG&E KU | Louisville Gas and Electric Company/Kentucky Utilities Company |
| LP | Low-Pressure |
| MCR | Maximum Continuous Rating |
| MFT | Master Fuel Trip |
| MW | Megawatts |
| NFPA | National Fire Protection Association |
| $NO_x$ | Nitrogen Oxide |
| NPHR | Net Plant Heat Rate |
| PA | Primary Air |
| PAM | Pole Amplitude Modulation |
| PM | Particulate Matter |
| psi | Pounds per Square Inch |
| rpm | Revolutions per Minute |
| SCAT | Stoichiometric Combustion Analysis Tool |
| $SO_x$ | Sulfur Oxide |
| VWO | Valves Wide Open |
| WFGD | Wet Flue Gas Desulfurization |

# 1.0 Executive Summary

## 1.1 STUDY BACKGROUND

E. W. Brown Station Units 1, 2 and 3 are 114 megawatts (MW) gross (107 MW net), 180 MW gross (168 MW net), and 457 MW (430 MW net), respectively. All three units currently fire pulverized coal. The units were originally designed to be base loaded units and currently operate in load-following mode.

Louisville Gas and Electric Company/Kentucky Utilities Company (LG&E KU) retained Black & Veatch Corporation (Black & Veatch) to perform a conceptual level study that includes the following:

- Evaluate the feasibility of converting Units 1, 2 and 3 from firing 100 percent coal to firing 100 percent natural gas. Co-firing is not being evaluated in this study.
- Estimate the potential impacts to unit performance when operating on 100 percent natural gas.
- Develop an order of magnitude cost estimate for all modifications required (including new natural gas burners, natural gas ignition system, natural gas pressure reduction/metering skids, etc.) to allow operation on 100 percent natural gas (including all natural gas piping from the main natural gas source off-site to the units).
- Estimate the emissions impacts resulting from firing natural gas.

## 1.2 NATURAL GAS SYSTEM

Estimates for one (1) new natural gas pipeline to transport the gas originating at the main natural gas source off-site from the main tie-in location which is located approximately ten (10) miles from the eastern edge of Dix Dam (property line) to the units were included. The natural gas piping from the main tie-in point to the inlet of the HP regulating stations is designed for an operating pressure of approximately 600 psig and a maximum allowable working pressure (MAWP) of 1,000 psig.

The new 30" piping will be below ground from the main tie-in to the cliff on the east side of the dam. The pipe is then routed down the west face of the cliff above the east bank of the dam discharge, then west to the plant property. The supply line will then be routed on the plant property and will follow the existing service roadways around the northeast area of the plant. The new line will arrive at a location northeast of the Unit 1 and Unit 2 cooling towers and branch into three (3) new high-pressure (HP) regulating, metering and heating stations which will reduce the pressure to approximately 150 to 200 psig. A branch off of the main line will be valved and capped for future use. From the HP pressure regulating stations, three (3) separate underground lines (one for each unit) will run parallel between the Units 1 and 2 cooling towers and arrive at a location underneath the Unit 2 precipitators, with the exception of the piping for Unit 3. Two (2) low-pressure (LP) regulating stations, one (1) for Unit 1 and one (1) for Unit 2 will be installed. The LP regulating station for Unit 3 will be located in an area northeast of the Unit 3 steam turbine building. Each of these LP regulating stations will reduce the natural gas pressure to approximately 50 psig. The gas lines will exit the LP (final) regulating stations and will be routed into each of the units and up to the respective burner decks. A main flow control valve and distribution headers will distribute and control the flow of gas to each burner level. At the burner front, a double block and vent valve arrangement will be utilized in accordance with NFPA requirements. Additional trip, isolation, and header vent valves will be included as part of the piping internal to the boiler building.

Figures showing the preliminary natural gas line routing are contained in Appendix A. Additional discussion concerning the arrangement of gas piping is provided in Section 3.2.

## 1.3 PERFORMANCE ANALYSIS

Unit 1 is a wall-fired unit that has a split backpass to assist in gas bias between the main steam and reheat steam circuits. The split backpass was modeled within Vista, and gas bias was altered by the model from the main steam side to the reheat side to converge upon a stable heat transfer solution. Boiler modeling revealed that the Unit 1 main steam temperature at full load was expected to decrease from 1,001 °F with coal to 800 °F with natural gas. The reheat steam temperature was predicted to undergo similar reductions, from a baseline of 1,017 °F with coal to 835 °F with natural gas. At the current predicted temperatures, Unit 1 is likely to put its LP turbine at-risk for high levels of condensation, and even if the gross load loss was recoverable, the unit may still require operation at a reduction in main steam flow. The predicted reduction in gross load was approximately 3.5 MW due to reduced main steam energy and approximately 9.3 MW due to reduced reheat steam energy, for a total loss of approximately 12.8 MW at full load.

Unit 2 is a tangential-fired unit with burner tilts, and the burner tilt capability was modeled within the Vista program and varied by the program to try to balance heat transfer between the main and reheat steam during natural gas combustion. Boiler modeling revealed that the Unit 2 main steam temperature at full load was expected to decrease from 1,020 °F with coal to 1,000 °F with natural gas. The reheat steam temperature was predicted to undergo similar reductions, from a baseline of 1,012 °F with coal to 977 °F with natural gas. To achieve these temperatures the burners were tilted from a baseline condition of -20° downward with coal, to +30° upward with natural gas. The predicted reduction in gross load was approximately 0.6 MW due to reduced main steam energy and approximately 2.9 MW due to reduced reheat steam energy, for a total loss of approximately 3.5 MW at full load.

Unit 3 is a tangential-fired unit with burner tilts, and the burner tilt capability was modeled within the Vista program and varied by the program to try to balance heat transfer between the main and reheat steam during natural gas combustion. Boiler modeling revealed that the Unit 3 main steam temperature at full load was expected to decrease from 968 °F with coal to 916 °F with natural gas. The reheat steam temperature was predicted to undergo similar reductions, from a baseline of 997 °F with coal to 910 °F with natural gas. To achieve these temperatures the burners were tilted from a baseline condition of +8° upward with coal, to +30° upward with natural gas. The predicted reduction in gross load was approximately 4.9 MW due to reduced main steam energy and approximately 18.8 MW due to reduced reheat steam energy, for a total loss of approximately 23.7 MW at full load.

An analysis was done to estimate the amount of increase in the fuel burn rate which would be needed in order to remove the derates from each of the three units. Unit 1 would be required to increase the fuel burn rate the greatest proportion relative to its full-load heat input. An additional 148 MBtu/hr is necessary to recover the lost load, which could lead to either tube overheating or even flame impingement upon the opposite walls for that unit (something which was not specifically modeled, but is a known risk factor based upon Black & Veatch experience). Unit 2 would be required to increase the fuel burn rate an additional 35 MBtu/hr to recover its lost load, and Unit 3 would be required to increase the fuel burn rate an additional 255 MBtu/hr to recover its lost load. These represent increased fuel burn rates of 11.7%, 1.9%, and 5.3% for Units 1, 2, and 3 respectively.

In each of the cases evaluated by the Vista program, the goal of the modeling was to try to hold gross power output constant. As a result, the potential net power was expected to "float" from case to case, and when burning 100 percent natural gas it was expected that the net power would increase, as there will be no power demand for the coal handling system, ash handling systems, mills, ESP, and scrubber. There will also be auxiliary power savings from the pumps and limestone handling equipment for the common wet limestone FGD system, since Units 1, 2 and 3 will be bypassing the WFGD system while operating on natural gas. Primary air fans were also eliminated in the Vista modeling, however it is possible that primary air fans could be utilized to support combustion by supplying additional air to the boiler in parallel with the forced draft fans.

A summary of performance for the E.W. Brown Units 1, 2, and 3 with no increase in the fuel burn rate is shown in the Table 1-1.

## 1.4 EMISSIONS

The short term emissions (as opposed to long term discussed in Section 4) resulting from converting the coal fired boilers to natural gas will be significantly different. Pipeline quality natural gas contains very little sulfur, chlorine, mercury, metals or particulates that are commonly found in coal. Natural gas has very little sulfur (typically 0.5 to 20 grains per 100 standard cubic feet) and resulting sulfur dioxide ($SO_2$) emissions are low enough that additional sulfur dioxide emission reduction will not be required. The WFGD system for Unit 3 will not need to be operated to control $SO_2$ emissions once the units are converted to natural gas firing.

Similarly, particulate emissions will be greatly reduced when burning natural gas. There will be small amount of both filterable and condensable particulate produced in the combustion process but this will be less than the currently permitted particulate emissions. The overall particulate emissions will decrease without operating any particulate control devices. The electrostatic precipitators on Units 1 and 2 and the fabric filter on Unit 3 will not need to be operated once the units are converted to natural gas firing. The ESPs and fabric filter will be decommissioned in place and the internals removed if desired. The cost for removal of the internals has not been included in the estimate. The boilers and all of the ducting will be thoroughly cleaned by LG&E KU to remove any of the residual ash prior to commissioning on natural gas.

The impact to nitrogen oxide ($NO_x$) emissions is more difficult to determine since it is dependent on many items including burner design, level of staging, and excess air level. The amount of fuel-bound nitrogen in natural gas is negligible compared to that found in coal. Due to this limited fuel-bound nitrogen, the amount of uncontrolled $NO_x$ generated is expected to be reduced on a lb/MBtu or lb/hr basis compared to coal. If the capacity factor changes for these units due to the change to Natural Gas firing then the overall $NO_x$ produced may increase on a ton per year basis.

Refer to Table 1-2 for the natural gas emissions estimate.

**Table 1-1 Performance Results**

| ULTIMATE FUEL ANALYSIS, WET BASIS | UNIT 1 | | UNIT 2 | | UNIT 3 | |
|---|---|---|---|---|---|---|
| | COAL | GAS | COAL | GAS | COAL | GAS |
| Target Gross Turbine Generator Load, MW | 109.43 | 109.43 | 182.03 | 182.03 | 448.03 | 448.03 |
| Turbine Derate, MW | 0 | 12.80 | 0 | 3.50 | 0 | 23.70 |
| Turbine Derate, percentage (approx) | NA | 11.7 | NA | 1.9 | NA | 5.3 |
| Maximum Gross Turbine Output, MW | 109.43 | 96.63 | 182.03 | 178.53 | 448.03 | 424.33 |
| Boiler Efficiency, % (HHV) | 85.29 | 83.35 | 86.33 | 83.31 | 87.36 | 84.36 |
| Net Plant Heat Rate, Btu/kWh (HHV) | 11,408 | 11,866 | 10,542 | 10,632 | 10,696 | 11,086 |
| Boiler Heat Input, MBtu/hr (HHV) | 1167.86 | 1262.14 | 1764.91 | 1843.15 | 4562.77 | 4820.68 |
| Coal Flow Rate, ton/hr | 51.71 | | 77.93 | | 202.57 | |
| Natural Gas Flow Rate, kcfm | | 19.77 | | 38.87 | | 75.50 |
| Main Steam Outlet Temperature, °F | 1,002 | 800 | 1,020 | 1,000 | 968 | 916 |
| Hot Reheat Steam Outlet Temperature, °F | 1,017 | 835 | 1,012 | 977 | 997 | 910 |
| Economizer Flue Gas Outlet Temperature, °F | 642.0 | 567.3 | 718.9 | 699.5 | 746.5 | 714.8 |
| Air Heater Flue Gas Outlet Temperature, °F | 355.3 | 316.5 | 340.7 | 322.0 | 317.2 | 292.1 |

Note: Table values are based on no increase in the fuel burn rate and no heat transfer surface modifications

**Table 1-2 Natural Gas Emissions Estimate (Uncontrolled at MCR)**

| | UNIT 1 | | UNIT 2 | | UNIT 3 | |
|---|---|---|---|---|---|---|
| | Coal | Natural Gas | Coal | Natural Gas | Coal | Natural Gas |
| $CO_2$, lb/hr | 240,768 | 147,500 | 362,146 | 215,250 | 927,437 | 563,200 |
| $NO_x$ , lb/MBtu | ~0.3 [2] | 0.12 – 0.25 | ~0.3 [2] | 0.10 -0.12 | 0.04 [3] | 0.08 – 0.12 [4] |
| CO, lb/MBtu | Note 1 | 0.15 | Note 1 | 0.15 | Note 1 | 0.15 |

Notes:

1. Baseline emissions were based on an emission factor of 0.5 lb-CO per ton of coal burned (USEPA AP-42) and heat input obtained from the US EPA Clean Air Markets database.
2. Based on data from 2016.
3. $NO_x$ emissions on coal based on targets for 2017 provided by LG&E KU which includes operation of the SCR.
4. $NO_x$ emissions shown for Natural Gas burners with overfire air. $NO_x$ reduction from the existing SCR system is not included.

## 1.5 EQUIPMENT MODIFICATIONS

### 1.5.1 Firing System Modifications

To support operation on natural gas on Unit 1, the existing coal fired burners will be removed and replaced with new burners equipped with a natural gas ring around the burner exterior and multiple natural gas spuds through the burner annulus. Depending on the burner design, the coal fired burners on Unit 2 and Unit 3 will be replaced with natural gas burners that will be located in the same location as the coal fired burners or in between the existing coal fired burners. The new gas burners will be located in each corner of the boilers The existing igniters will be replaced with natural gas igniters to eliminate the oil supply system from the units. The existing scanners will be replaced with dual infrared/ultraviolet (IR/UV) or tri-color VIR/IR/UV flame scanners. The existing coal burners and oil ignition system components will be removed.

High level cost estimates have been discussed for possible modifications to the heat transfer surfaces in Article 3.4.1. These estimated costs are based on previous projects and will need to be further evaluated during detailed design. These costs are not included in the project estimate in Section 5.

### 1.5.2 Fan Modifications

Modifications to the FD and ID fans are not required for the gas conversion on either Units 1, 2, or 3 because all combustion air and flue gas fans appear to be sufficiently sized. The net result of the natural gas conversion, the bypassing of the wet flue gas desulfurization (WFGD), and the routing the flow from each of the units to the original Unit 3 chimney will cause a reduction in the flue gas system pressure drop and fan power required on each of the units.

### 1.5.3 Electrical Upgrades

Renovations to existing raceway and equipment with electrical interfaces in the vicinity of the new natural gas piping will be required in accordance with National Electrical Code (NFPA 70). The cost estimate includes allowances for moving equipment or upgrading the equipment through z-purged enclosures, and replacement by intrinsically safe or explosion proof equipment models depending on potential pipe routing.

### 1.5.4 Control System Modifications

The DCS for Units 1 and 2 will require modification to the combustion control/boiler modulating control (BMC) system and burner management system (BMS) of the DCS. I/O from the present Unit 1 and 2 BMS systems can be re-used for the gas conversion but will require re-configuration/re-programming and re-terminating. The DCS for Unit 3 will require modification of the combustion control system and replacement of the Allen Bradley PLC-based burner management system with a new BMS. A new main fuel trip (MFT) cabinet for the natural gas burners and associated equipment for each unit will be required to replace the present MFT cabinets. Allowances for all modifications and additions to the Units 1, 2, and 3 control systems are included in the cost estimate.

## 1.6 COST ESTIMATE

This section presents the estimated costs associated with implementing the modifications necessary to allow operation on natural gas. The cost estimate includes estimated costs for equipment and materials, construction labor, engineering services, construction management, indirect costs, and other costs. Provided costs are order of magnitude +/- 30% cost estimates.

The cost estimates in this study only account for converting the E.W. Brown units from coal to natural gas. Estimates do not account for capital, operation and maintenance costs that might be incurred as a result of extending the life of the units beyond current retirement plans.

The estimate is further broken down and explained in greater detail in Section 5.0. Refer to Table 1-3 for a summary of the capital cost estimate.

**Table 1-3 Capital Cost Estimate Summary – Unit 1**

| CAPITAL COST (2017 USD) | | | |
|---|---|---|---|
| **Scenario [1,2,3]** | **Scenario 1** | **Scenario 2** | **Scenario 3** |
| Direct Cost (DC) | $76,451,400 | $58,941,800 | $53,663,700 |
| Indirect Cost (IC) | $30,580,560 | $23,576,720 | $21,465,480 |
| Total Capital Investment (DC) + (IC) | $107,031,960 | $82,518,520 | $75,129,180 |
| Insurance and Bonds | $2,140,639 | $1,650,370 | $1,502,584 |
| Hazardous Material Abatement Allowance | $1,000,000 | $1,000,000 | $1,000,000 |

| CAPITAL COST (2017 USD) | | | |
|---|---|---|---|
| Owner Costs | $5,351,598 | $4,125,926 | $3,756,459 |
| **Total Project Cost** | **$115,524,197** | **$89,294,816** | **$81,388,223** |

Notes:
1. Scenario 1 – All three (3) units converted to 100% natural gas firing.
2. Scenario 2 – Units 1 and 2 converted to 100% natural gas firing; Unit 3 firing 100% coal.
3. Scenario 3 – Unit 3 converted to 100% natural gas firing; Units 1 and 2 – retired.

## 1.7 SUMMARY

LG&E KU can successfully switch to 100 percent natural gas at the E. W. Brown Station on Units 1, 2 and 3, with costs incurred for burner modifications, natural gas piping additions, draft system upgrades, controls system upgrades, and electrical system upgrades. Overall operations should be improved, especially in the areas of slagging and fouling and any other ash-related impacts. The reliability/availability of the units will be increased due to the fact that outages due pulverizer malfunctions, coal handling equipment malfunctions, and various components associated with coal firing will not occur. Sulfur oxide ($SO_x$), sulfuric acid ($H_2SO_4$), and particulate matter (PM) emissions will be greatly reduced. $NO_x$ emissions are expected to be reduced on a lb/MBtu basis as shown in Table 1-2, but depending on the capacity factor of the units, the overall $NO_x$ production may increase.

Although boiler efficiency and net plant heat rate (NPHR) will both be reduced as a result of natural gas combustion, the overall carbon dioxide ($CO_2$) emissions on any hourly basis for the units and the plant will be reduced while firing natural gas.

The performance and overall costs estimates developed for these analyses are considered to be budgetary level costs (±30% accuracy). Some portions of the cost estimate, such as the natural gas burner components, have a better accuracy than the ±30%. Burner vendors were contacted to obtain pricing and to provide performance values used in this analysis. During the next phase of this project, a more definitive cost and performance estimate is recommended for LG&E KU's use in developing its overall project budget.

The following activities will need to be performed during the next phases of this project to support the natural gas conversion:

- Detailed performance modeling of the boiler and heat transfer surfaces.
- Development of detailed pipe routes, cable trays, and equipment arrangements (including equipment to be moved or upgraded for NFPA compliance).
- Detailed pricing, including the preparation of a more detailed burner specification, contacting potential equipment suppliers to obtain firm priced quotations and guaranteed emissions estimates.

- Assessment of the environmental permitting requirements for the natural gas conversion. The permitting process should be started when the contract fuel analysis and emissions estimates are obtained.
- Review of the conceptual routing by a pipeline specialist to identify the requirements for right a ways, permitting, legal review, construction, and testing.

# 2.0 Introduction

This natural gas conversion report presents the results of the initial study performed by Black & Veatch to evaluate the conversion of Units 1, 2 and 3 from coal fired operation to 100 percent natural gas fired operation. The natural gas conversion modifications discussed will allow the units to be operated slightly less than full load operation on natural gas when compared to firing 100% coal. The objective of the study is to technically evaluate the natural gas conversion's feasibility and performance, identify major impediments, and develop an order of magnitude cost estimate for implementation of the units' modifications.

# 3.0 Analysis

## 3.1 CONCEPTUAL DESIGN BASIS

The following subsections describe the design basis used for the conceptual design. The design basis was developed based on the calibrated Vista model results. Each of the previously developed unit models were updated and calibrated based on recent information and data provided by LG&E KU.

### 3.1.1 Unit Description

Unit 1 is an approximately 114 MW gross, front wall fired, split furnace, subcritical, pulverized coal boiler supplied by Babcock & Wilcox. The unit was commissioned in 1957. The unit has pressurized mills with hot primary air fans, each supplying coal to one row of four burners (16 total burners). Unit 2 is an approximately 180 MW gross, tangential fired, subcritical, pulverized coal boiler supplied by Combustion Engineering (now GE-Alstom). This unit has four exhauster type mills, each feeding one row of coal nozzles, one in each corner. Unit 3 is an approximately 457 MW gross, tangential fired, subcritical, pulverized coal boiler supplied by Combustion Engineering (now GE-Alstom). This unit has five exhauster type mills, each feeding one row of coal nozzles, one in each corner of the boiler.

Units 1 and 2 are equipped with ESPs to control particulate emissions. Unit 3 is equipped with a baghouse to control particulate emissions. The flue gas streams from Units 1, 2, and 3 currently merge together to pass through a common WFGD system to control $SO_x$ emissions. Unit 2 is currently equipped with a FGD bypass duct that allows the flue gas to exit out the original Unit 3 stack. The FGD bypass has not been utilized since the implementation of the MATS rule.

The basis for determining the maximum load capability for each unit while operating on natural gas was the Vista model results. The system analysis consisted of modifications required to operate on 100 percent natural gas, based on previous Black & Veatch gas conversion projects. The draft system analysis was examined to determine its adequacy to support natural gas firing and then identify if any upgrades were required.

The natural gas supply system will have a turndown capability that is expected to be lower than the steam turbine minimum operating capability. A single level of main fuel burners operating with a turndown ratio of 5 to 1 can provide less than 10 percent heat input to each boiler. Prior to determining the actual minimum load operating point, the OEMs should also be consulted to determine the minimum safe operating condition for all major equipment items.

## 3.2 NATURAL GAS SYSTEM CONCEPTUAL DESIGN

### 3.2.1 Natural Gas Supply

A conceptual design was developed for a natural gas supply piping, heating, and regulating system to supply natural gas at the required burner pressure to Units 1, 2 and 3. These costs are considered to be “common” to all three units in the cost estimate. The conceptual design is preliminary and was developed to support the budgetary cost estimate. Engineering tools, past project experience, and good engineering judgment were utilized to develop the conceptual design in accordance with national standards and codes. The design shall be considered conceptual and should not be used for the selection or procurement of equipment, materials, or construction contracts. Additional effort is required to determine the actual design of the system during a detailed design phase.

#### 3.2.1.1 Interconnection to Units 1, 2, and 3

For the conceptual design, natural gas for the project will be supplied at an assumed pressure at the main gas line connection point of 600 psig. For this analysis, a new thirty (30) inch natural gas line was assumed to branch from a main line approximately ten (10) miles from the plant. This line was assumed to transport natural gas along the same path as the existing natural gas line servicing the E. W. Brown combustion turbines. No additional allowances were assumed for right-of-way or property rights. The new 30" line will reach the plant boundary at approximately the same location as the existing gas line used for the combustion turbine units, on the east side of Dix Dam. From this location, the new supply line will continue north below ground, to a point suitable for routing on the west face of the cliff down to the riverbed. Due to the limited remaining distance to the plant, and cost associated with the river crossing, the line size will be reduced to 24" at this point. Four (4) options for crossing the river downstream of Dix Dam were conceptualized:

- Routing exposed and attached to the north face of the hydro generation building and Access Bridge (lowest cost).
- Routing to a pit along the river banks and boring horizontally below the riverbed (The cost estimate for this option was included in the overall project estimate.).
- Routing across a new bridge crossing over the river
- Routing across a simplified pipe bridge with minimal structure added to support the pipe over the river.

Early in the study, LG&E KU expressed a preference for the new supply line to be buried the entire length of the Dix River crossing. Due to the line size and the depth of the dam (and therefore cliff height) horizontal directional drilling contractors were contacted to estimate feasibility and construction costs. A horizontal directional drill project of this pipe diameter and length, due to the depth of the Dix River crossing appears to be outside of the experience base of many traditional directional drillers. The one rough order of magnitude estimate that was obtained was in excess of $4 million and made use of alternate pipeline materials of construction which may not be appropriate for this service. Should LG&E KU wish to further consider this more expensive underground crossing option, it is recommended that additional contractors be provided more site-specific data to provide a more accurate assessment of the feasibility and cost.

No allowances were included for pipeline pig launching and receiving stations for the 10 mile pipeline. Such a station at the Dix River end of the pipeline would require additional land acquisition, equipment, and access roadway which were not reflected in the documents showing the current gas pipeline serving the site.

The supply line continues from the west side of Dix River on the plant property and will follow the existing service roadways around the northeast area of the plant. The new line will arrive at a location northeast of the Unit 1 and Unit 2 cooling towers and branch into three (3) new high-pressure (HP) regulating, metering and heating stations which will reduce the pressure to approximately 150 to 200 psig. A branch off the main line will be valved and capped for future use. From the HP pressure regulating stations, three (3) separate underground lines (one for each unit) will run parallel between the Units 1 and 2 cooling towers and arrive at a location underneath the Unit 2 precipitators, with the exception of the piping for Unit 3. Two (2) low-pressure (LP) regulating stations, one (1) for Unit 1 and one (1) for Unit 2 will be installed. The LP regulating station for Unit 3 will be located in an area northeast of the Unit 3 steam turbine building. Each of these LP regulating stations will reduce the natural gas pressure to approximately 50 psig. The gas line will exit the LP (final) regulating stations and will be routed into each of the units and up to the respective burner decks. The natural gas piping from the main tie-in point to the inlet of the HP regulating stations is designed for an operating pressure of 600 psig and a maximum allowable working pressure (MAWP) of 1,000 psig.

The new 30” supply line will be required to support the coal to natural gas conversion of the boilers on Units 1, 2 and 3, provide natural gas to support the installation of a new 2-on-1 combined cycle plant and feed the simple cycle combustion turbines. From the plant boundary on the east side of Dix Dam, Black & Veatch developed a preliminary sketch for the pipe routing to estimate pipe lengths to support the order of magnitude cost estimate. A conceptual routing of these pipelines is provided in Appendix A. No conceptual pipe routing drawings were developed for the 10 mile gas line running between the main supply line and the plant boundary on the east side of Dix Dam as it was assumed that the new line would parallel the existing line.

For all underground piping, the actual pipe routing will be determined during detailed design and based on site surveys and further investigations of site geology and existing undergrounds and utilities. Further investigations will also be required to assess the technical requirements and alternative methods of routing the natural gas pipelines in the dam discharge, along with permitting constraints, both construction and environmental. For the cost estimate, it was assumed that the underground natural gas piping will be installed via open trench and backfill for all crossings other than Highway 27.

For cost estimating purposes, the on-site natural gas supply piping to the plant was conservatively sized at 24 inch Schedule 80. Sizing of the pipe is based on the calculated natural gas flow rate, as provided in Section 3.3, plus a 10 percent flow margin to maintain a natural gas velocity below 7,500 feet per minute (ft/min) which is common for on-site natural gas branch lines. Option pricing has been included for a 20 inch schedule 80 gas piping, which would be adequate for supplying natural gas to the three boilers and to the combustion turbines, minus the allowance for a new 2-on-1 combined cycle plant.

The natural gas pressure will be regulated in two stages: once in HP regulating stations (reduced from main line supply pressure to 150-200 psig) followed by LP regulating stations (reduced from 150-200 to 50 psig). The HP regulating stations will be located northeast of the plant and will reduce the pressure of the supply natural gas before being routed inside the plant. A natural gas heating station will be located in each of the units' piping upstream of the HP regulating stations. The proposed locations of the natural gas heating and HP regulating stations, and the LP regulating stations, are shown on the pipeline routing sketches in Appendix A. Locations are based on a site visit and review of available drawings and satellite photography. During future efforts, regulating station locations may change. The final location of the HP and LP regulating stations (excluding demolition) is not expected to have an appreciable effect on the overall cost estimate.

Because of the Joule-Thomson effect, the temperature of natural gas can change during a pressure reduction operation, and its final temperature is related to the amount of pressure drop across the pressure regulating valve. Increasing the temperature of the natural gas may be required prior to pressure reduction to overcome the possibility of moisture condensation and freezing following the cooling effect of the pressure reduction operation. Insulation of the natural gas piping is included as required.

Natural gas heating can be accomplished with natural gas fired heaters, electrical resistance heaters, or through the use of steam. For the purposes of this study, natural gas fired water bath type heaters, similar to the ones used for the combustion turbines, were utilized. With a water bath type heater (which must also be considered as part of the air permit modifications for the project), natural gas is indirectly heated in a large vessel containing a fire tube and a natural gas coil. The vessel is filled with a water/glycol mixture, which transfers heat from the combustion gases within the fire tube to the natural gas flowing through the natural gas coil. Preliminary heater sizing was calculated assuming a supply pressure of 480 to 500 psig and a final reduced pressure after the LP regulating stations of 50 psig. Each of the 100% gas heaters sized at 1.5 MBtu/h for Unit 1, 2.24 MBtu/h for Unit 2, and 5.75 MBtu/h for Unit 3 (heat input to natural gas) located upstream of each of the HP reducing stations will be designed to maintain a natural gas temperature above 50° F following the LP natural gas regulating stations. The heaters will be located on a heavy concrete pad.

At the location of the natural gas heater and HP regulating stations, the single supply line will be brought aboveground and split into three (3) individual lines, each going to a dedicated gas heater, HP regulating and metering station as shown on the conceptual flow diagrams in Appendix B. Each line will include a flow meter to measure the flow of natural gas into the plant. Following the flow meter, the line will be routed to a natural gas fired water bath heater and then to a skid mounted HP natural gas regulating station. This skid will include two (2) HP natural gas regulating valves. The double valve arrangement will allow for turndown of the HP natural gas regulating station for boiler startup. A pilot operated monitor/worker valve arrangement was assumed based on the direction of American Society of Mechanical Engineers (ASME) B31.1 Section 122.8, Piping for Flammable Gases, Toxic Fluids (Gases of Liquids), or Nonflammable Nontoxic Gases. With a monitor/worker valve arrangement, a full pressure relief valve is not required downstream of the regulating station, provided a fail-safe, trip-stop valve and a safety relief valve are included. With a monitor/worker valve arrangement, redundancy is provided in the arrangement for overpressure protection of downstream piping.

The fail-safe, trip-stop valve will be installed to automatically close within 1 second at or below the design pressure of the downstream piping. The safety relief valve will provide overpressure protection from any seat leakage through the 2 x 50 percent monitor/worker valve station when closed.

A conceptual routing of the underground pipeline is provided in Appendix A. As previously stated, the main supply piping will branch into three (3) separate lines into a dedicated gas heater and HP pressure regulating station skids.

The LP regulating stations are arranged similarly to the HP regulating stations. The natural gas pressure is assumed to be reduced to 50 psig at the LP regulating stations. Each dedicated boiler supply line contains a 2 x 50 percent monitor/worker pressure regulating valve arrangement followed by a fail-safe, trip-stop valve and safety relief valve.

Following the LP regulating stations, dedicated lines will be routed aboveground to Units 1, 2 and 3. The piping between the HP and LP regulating stations are located underground and sized. based on the following values provided by LG&E KU Generation Planning plus a 10 percent flow margin to maintain a natural gas velocity below 7,500 ft/min (Black & Veatch standard for in-plant natural gas piping) at a regulated pressure of 50 psig:

- 26,000 MBtu/h – natural gas supply for 2x1 NGCC, Steam Plant (3 boilers), SCCTs
- 20,000 MBtu/h – natural gas supply for Steam Plant (3 boilers), SCCTs [alternate]

#### 3.2.1.2 Units 1, 2 and 3 to Burner Fronts

At the boilers on Unit 1, 2 and 3, flow control valves and distribution headers will distribute and control the flow of natural gas to the burners located on the levels noted below:

- Unit 1 – four (4) levels of burners, boiler front wall only
- Unit 2 – four (4) levels of burners, each corner of the boiler
- Unit 3 – five (5) levels of burners, each corner of the boiler

At each burner, a double block and vent valve arrangement will be furnished. Additional trip, isolation, and header vent valves will be included as part of the piping internal to the boiler building. Piping and valving internal to the boiler building is included as part of the boiler modification mechanical costs in the order of magnitude cost estimate.

### 3.2.2 Fuel Gas System Design Criteria

Relevant criteria for the new fuel gas system are shown in Table 3-1.

**Table 3-1 Units 1, 2 and 3 Fuel Gas System Design Criteria**

| UNIT OUTPUT | 110 MW GROSS (UNIT 1) | 180 MW GROSS (UNIT 2) | 457 MW GROSS (UNIT 3) |
|---|---|---|---|
| Boiler Efficiency, HHV | ~ 83.35% | ~ 83.31% | ~84.38% |
| Boiler Efficiency, LHV | ~91.98% | ~ 91.94% | ~93.12% |
| Fuel Gas, HHV | 1,064.2 Btu/cf | 1,064.2 Btu/cf | 1,064.2 Btu/cf |
| Fuel Gas Supply Pressure at Interconnection Point | 600 psig | 600 psig | 600 psig |
| Fuel Gas Flow per Unit, HHV | 19,770 cfm<br>1,262.14 MBtu/h | 28,870 cfm<br>1,843.15 MBtu/h | 75,530 cfm<br>4,822.49 MBtu/h |
| Fuel Gas Flow per Burner | 80 MBtu/h | 115 MBtu/h | 242 MBtu/h |
| Regulation Pressure (downstream of LP pressure regulating stations) | 50 psig | 50 psig | 50 psig |

### 3.2.3 Codes and Standards

The conceptual design is based on meeting applicable national codes. The following are the most significant codes and standards applicable to this conceptual design:

- NFPA 85 will be the governing code used in determining the igniter and burner arrangement and operating principles based on a multiple burner boiler.
- ASME B31.1 Power Piping Code and other ASME codes will be used for mechanical design.
- NFPA 497 and the National Electric Code (NFPA 70) will also be used in identifying electrical hazardous area classification issues that must be addressed.

State and local codes have not been evaluated.

## 3.3 PERFORMANCE ANALYSIS

To efficiently quantify the high level performance and emissions impacts associated with changing the fuel source from coal to 100 percent natural gas, the Black & Veatch Fuels Unit utilized the Electric Power Research Institute Vista fuel quality impact analysis program. This program specializes in predicting how changes in fuel quality or fuel sources at a coal-fired power plant will impact plant performance, derates, emissions, maintenance and availability, and economics. LG&E KU was one of the original testers of this program, and has used this program and its precursor, the Coal Quality Impact Model, since the early 1990's. The E.W. Brown units had been previously modeled in the program, and used for several performance studies in the past by both LG&E KU and Black & Veatch.

The first part of this task was to update the existing Brown Vista models, which were last updated in 2011 as part of a maintenance and reliability study. This entailed three sub-tasks:

- Adding new equipment items to the unit models, such as the new induced draft fan to Unit 1 and the pulse-jet fabric filter (PJFF) to Unit 3.
- Updating the baseline performance of the 3 units with coal combustion.
- Updating the baseline coal quality data for the units.

Black & Veatch worked with LG&E KU personnel to acquire updated plant equipment data, and this was gathered both during the site visit and from follow-up work after the site visit. This data was added to the models and no significant challenges were encountered.

### 3.3.1 Fuel Quality

Black & Veatch also worked with LG&E KU personnel to acquire the best estimate for coal quality data, and was advised to use coal quality data collected during testing done for Units 2 and 3. This coal quality data for Units 2 and 3 consisted of the higher heating value, proximate analysis, and ultimate analysis, but did not include the ash mineral analysis, Hardgrove Grindability Index, or coal ash fusion temperatures. As a result, a double-composite coal was developed for each of these units. First, an average of the test data heating value, proximate, and ultimate analysis was developed for Unit 2 and 3, and this data was used along with the last complete coal quality data set for the Brown units which contained the ash mineral analysis, Hardgrove Grindability Index, or coal ash fusion temperatures. This data was checked for internal and external consistency, and was found to be very reasonable and consistent. Unit 1 coal quality data was developed from a 50/50 blend on a mass basis of the Unit 2 and Unit 3 coal quality.

All natural gas fuel quality data was supplied by LG&E KU, and for this study represented data provided from November, 2016. The analysis in Table 3-2 is an average of six analyses provided. It should be noted that the fuel analysis provided did not include sulfur content for the natural gas. It is typical for natural gas to have some nominal sulfur content due to the odorant that is commonly added, although the sulfur content of natural gas is significantly lower than that found in coal. Any nominal fuel sulfur content from the odorant will likely have a negligible effect on the fuel heating value and required natural gas flow rate and will fall within the accuracy of the study.

During detailed design, it is recommended that the natural gas fuel analysis be investigated in greater detail to determine the maximum foreseeable sulfur content shown in the contract with the natural gas supplier. The maximum sulfur content should be used to determine the maximum $SO_2$ and $H_2SO_4$ emissions for permitting purposes. Emissions are further discussed in Section 3.10.

**Table 3-2 Natural Gas Analysis**

| COMPOUND | AVERAGE VALUE |
|---|---|
| Carbon Dioxide, % vol | 0.177 |
| Nitrogen, % vol | 0.369 |
| Methane, % vol | 92.182 |
| Ethane, % vol | 6.770 |
| Propane, % vol | 0.400 |
| Iso-Butane, % vol | 0.036 |
| N-Butane, % vol | 0.044 |
| Iso-Pentane, % vol | 0.010 |
| N-Pentane, % vol | 0.006 |
| Hexane, % vol | 0.009 |
| **Total** | **100.00** |
| HHV, Btu/scf (calculated) | 1,064 |
| LHV, Btu/scf (calculated) | 960 |

LG&E KU has elected not to retain solid fuel burning capability following the conversion to natural gas.

The coal analyses used to analyze baseline data is shown in Table 3-3.

**Table 3-3 Baseline Coal Analysis**

| ALL VALUES ON AN AS-RECEIVED (WET) BASIS | UNIT 1 | UNIT 2 | UNIT 3 |
|---|---|---|---|
| Higher Heating Value, Btu/lbm | 11,293 | 11,324 | 11,262 |
| Moisture, % | 12.81 | 12.89 | 12.72 |
| Ash, % | 8.84 | 8.51 | 9.16 |
| Volatile Matter, % | 37.04 | 37.80 | 36.29 |
| Fixed Carbon, % | 41.31 | 40.80 | 41.83 |
| Ultimate Analysis | | | |
| Carbon, % | 62.38 | 62.80 | 61.97 |
| Hydrogen, % | 4.44 | 4.52 | 4.36 |
| Nitrogen, % | 1.38 | 1.41 | 1.34 |
| Sulfur, % | 3.15 | 3.24 | 3.06 |
| Oxygen, % | 7.01 | 6.63 | 7.39 |

### 3.3.2 Baseline Performance Data

LG&E KU advised Black & Veatch to utilize two test periods from 2016 to gather baseline performance data for Units 2 and 3. For the best baseline data to use in Vista for calibrating the models, Black & Veatch prefers to use data from when the unit load was stable for several hours at or near the normal MCR. This allows time for the turbine cycle and boiler equipment to settle any performance and operations transients, and gives a better average to use for boiler performance data.

No such testing was done for Brown Unit 1, so the Black & Veatch Remote Performance Monitoring (RPM) Center analyzed the Unit 1 performance data to find the best time to calibrate the model. Figure 3-1 shows two data points of highest loads for U1: 2:00 PM - 5:30 PM CDT August 11, 2016 or 9:30 AM – 2:30 PM CDT September 6, 2016.

Closer examination of the data from August 11, 2016, revealed from 2:20 PM to 5:20 PM August 11, 2016 as shown in Figure 3-2, the unit load, main steam temperature, and net plant heat rate appeared relatively steady. Main steam pressure had one excursion, briefly up to approximately 1,475 psig, while the governor valve throttled back for a few minutes.

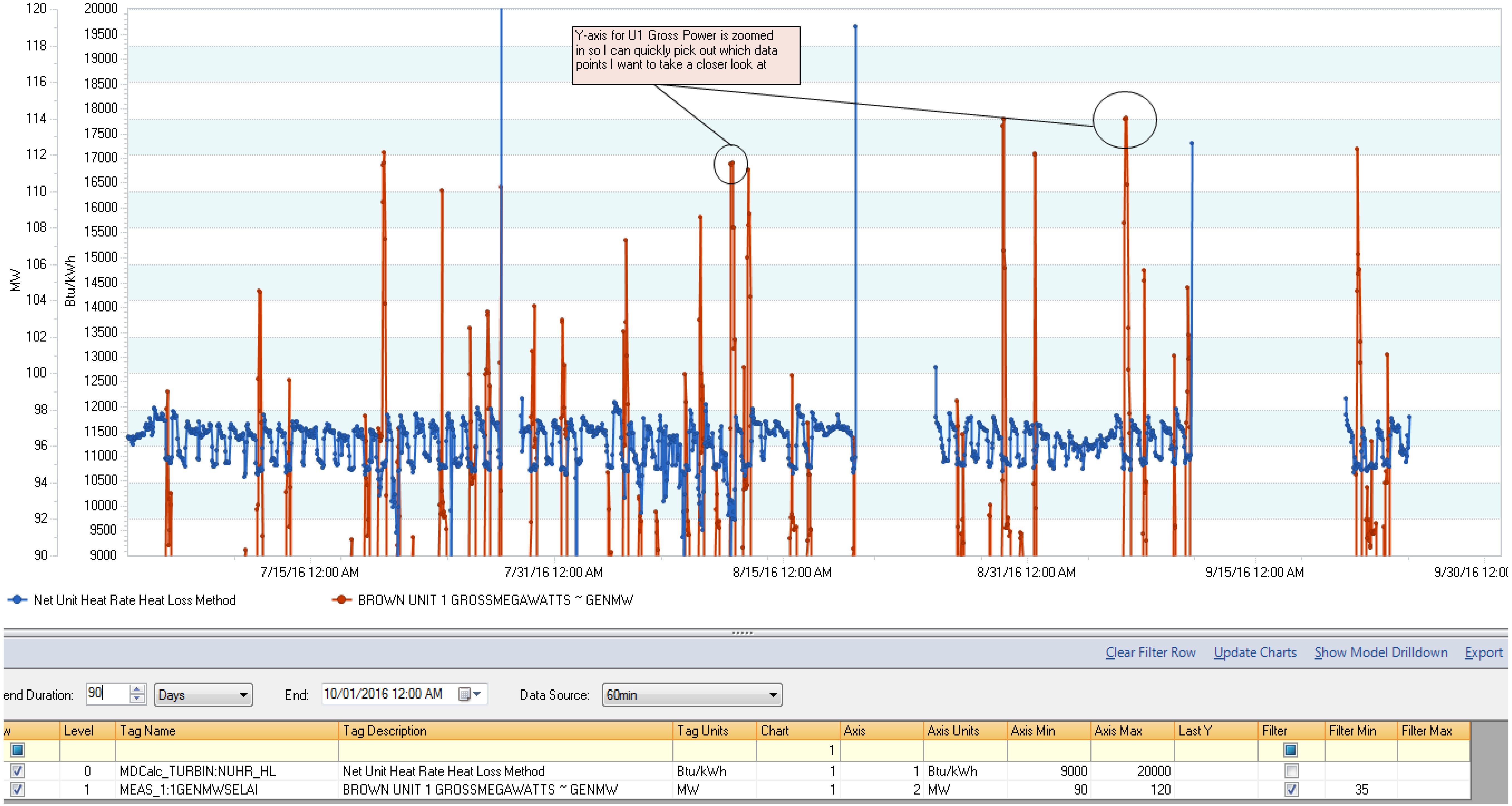
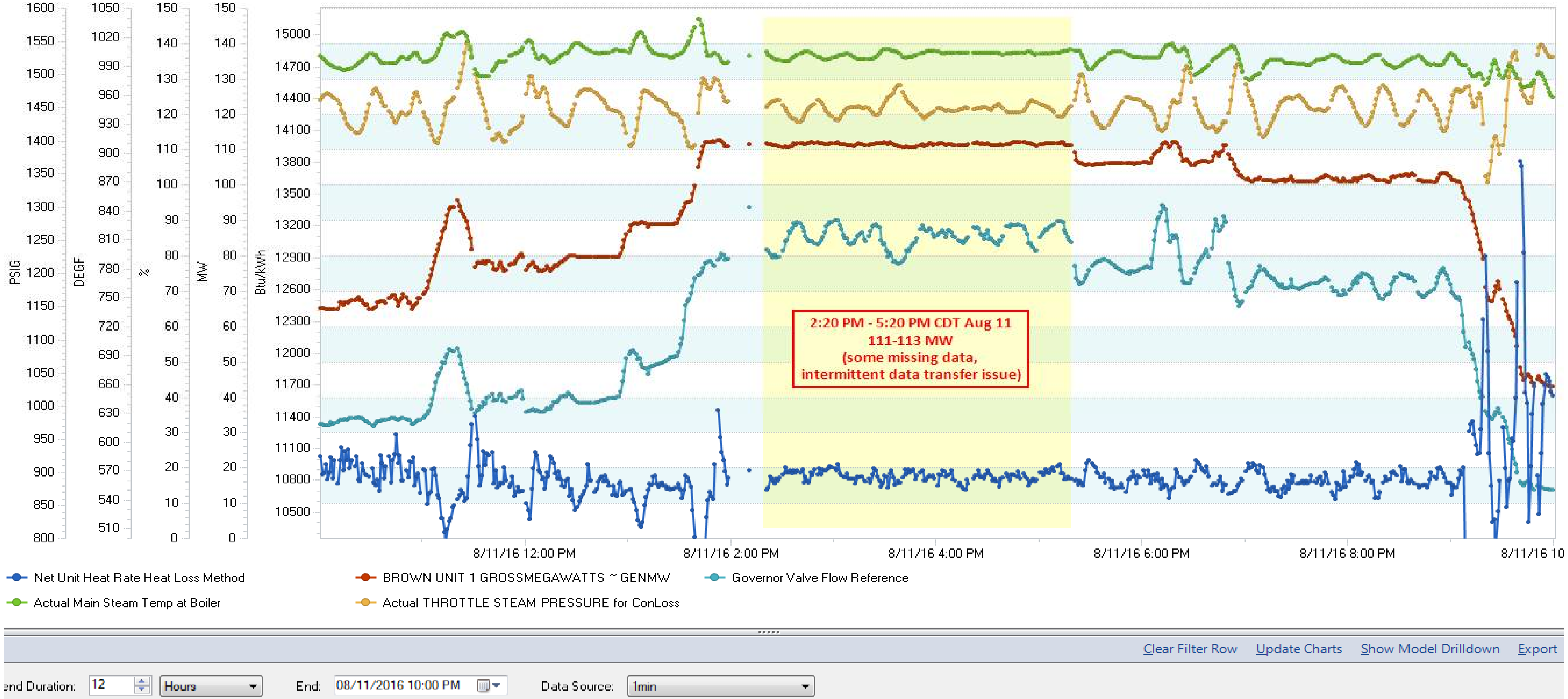



**Figure 3-1** **Unit 1 Plant Data from data from July and August 2016**




| w | Level | Tag Name | Tag Description | Tag Units | Chart | Axis | Axis Units | Axis Min | Axis Max | Last Y | Filter | Filter Min | Filter Max |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | 1 | | | | | | | | |
| ☑ | 0 | MDCalc_TURBIN:NUHR_HL | Net Unit Heat Rate Heat Loss Method | Btu/kWh | 1 | 1 | Btu/kWh | 10250 | 15250 | | ☐ | | |
| ☑ | 1 | MEAS_1:1GENMWSELAI | BROWN UNIT 1 GROSSMEGAWATTS ~ GENMW | MW | 1 | 2 | MW | 0 | 150 | | ☐ | | |
| ☑ | 5 | MEAS_1:11TURTCSGOVVLVREFCO | Governor Valve Flow Reference | % | 1 | 3 | % | 0 | 150 | | ☐ | | |
| ☑ | 11 | MDCalc_LOSS_ACTUAL:MST | Actual Main Steam Temp at Boiler | DEGF | 1 | 4 | DEGF | 500 | 1050 | | ☑ | 0 | |
| ☑ | 11 | MDCalc_LOSS_ACTUAL:THROTTLEP | Actual THROTTLE STEAM PRESSURE for ConLoss | PSIG | 1 | 5 | PSIG | 800 | 1600 | | ☐ | | |

**Figure 3-2 Unit 1 Plant Data from data from 2:20 PM to 5:20 PM on August 11, 2016**

This time period was also close to the times the fuel was sampled for the VWO tests at Brown Units 2 and 3 (August 3 and July 28th, respectively.) As a result, this data was used in order to provide the best fuel and performance timing consistency, rather than the other Unit 1 high load period of September 6th.

For Brown Unit 2 the Black & Veatch RPM Center examined time periods in August, 2016 when the unit was operating at full load conditions. In Figure 3-3, the red trend line shows the Unit 2 load for that month, and two periods where Unit 2 was at its highest load are circled on the graphic. The first period was August 3, 2016, and the second was August 31, 2016. The baseline fuel sample provided by LG&E KU was collected from each feeder during the VWO test on August 3. There was a Unit 2 outage from August 19 to 25, 2016.

Figure 3-4 focuses on August 3, 2016, when Brown Unit 2 ran a unit capability test by starting at lowest load point, then successively opening each throttle valve. The purple trend line shows the percent valves wide open.

Figure 3-5 shows the final step to the VWO condition, which started at 4:52 AM CDT and closed down at 6:13 AM CDT.

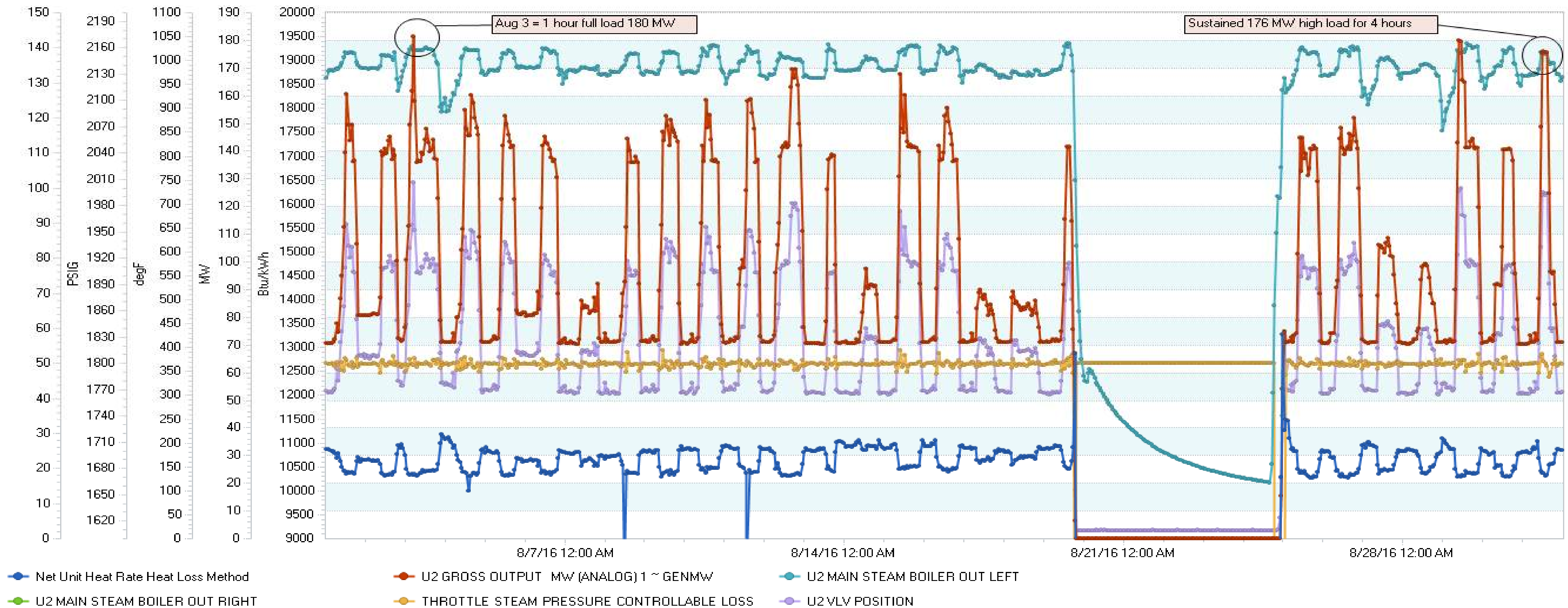
The net plant heat rate (NPHR) looked relatively steady while Unit 2 was at VWO. Therefore, for calibrating the Vista model of Brown Unit 2, the VWO test from August 3, 2016, from 5:00-6:00 AM CDT was chosen because it was when the fuel quality was sampled and the plant performance data appeared steady.

For Brown Unit 3 a similar trend line analysis process was conducted to find the best calibration time range to extract data from. In Figure 3-6, the red trend line shows the Unit 3 load for July-August 2016 (the data shown is filtered for gross power >290 MW). Circled are two periods where Unit 3 was at highest load. The first was July 28, 2016, and the second was August 29, 2016. Fuel samples were collected from each feeder during the VWO test on July 28. Unit 3 had multiple outages in August 2016: 13-17th, 17-18th, 20-23rd, then coming offline Aug 29th.

Figure 3-7 shows the Unit 3 capability tests which were run on July 28th, starting at low load and opening successive valve positions.

Figure 3-8 shows the unit load, net plant heat rate, and main steam temperature while valves 7 & 8 were wide open. For the first hour at VWO the unit load looked unstable, swinging between 430 to 450 MW. For roughly the next half hour, at 9:15-9:45 AM CDT, unit load seemed more stable between 445-452 MW.

While it is preferable to have a greater duration of data at a steady-state high load point, this data set was the best available at this juncture. The Brown Unit 3 load, net plant heat rate, and main steam temperature appeared more stable towards the last half-hour of VWO on July 28th. As fuel quality was sampled during this time, this short period was chosen for calibrating the Vista model.

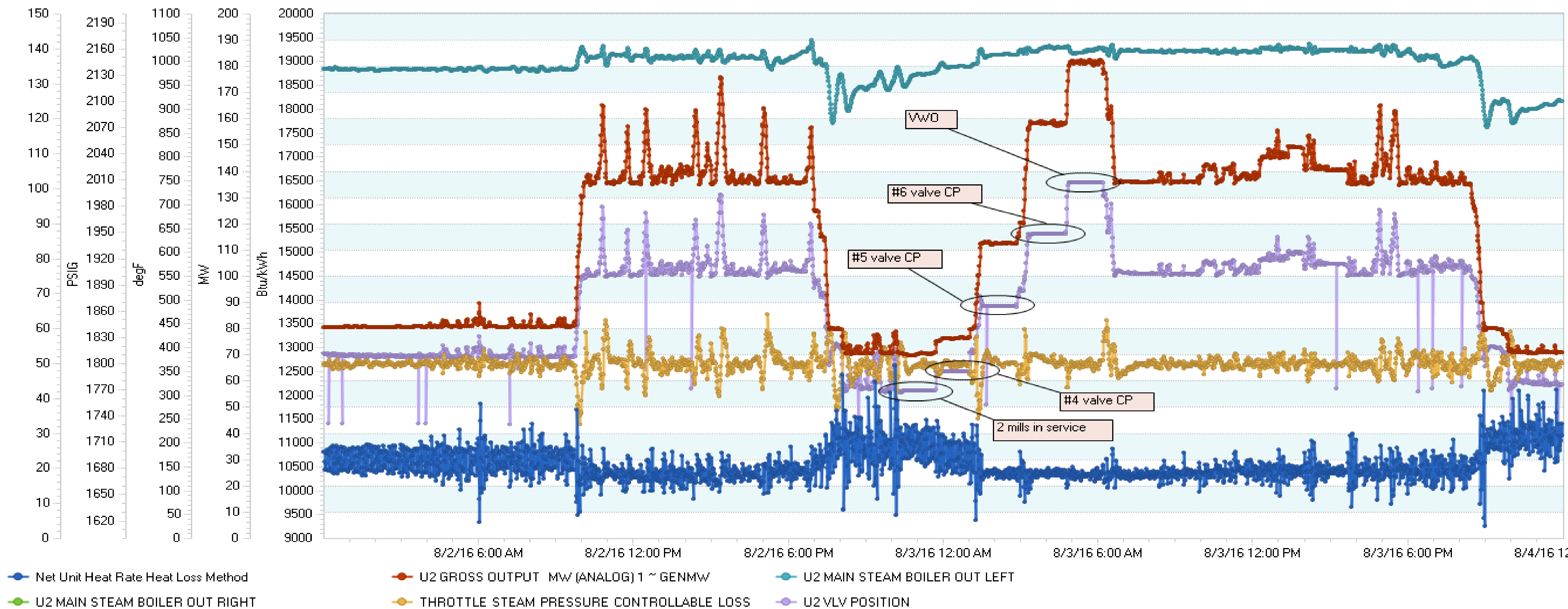



Clear Filter Row  Update Charts  Show Model Drilldown  Export

end Duration: 31 Days  End: 09/01/2016 12:00 AM  Data Source: 60min

| w | Level | Tag Name | Tag Description | Tag Units | Chart | Axis | Axis Units | Axis Min | Axis Max | Last Y | Filter | Filter Min | Filter Max |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | 1 | | | | | | | | |
| | 0 | MDCalc_TURBIN:NUHR_HL | Net Unit Heat Rate Heat Loss Method | Btu/kWh | 1 | 1 | Btu/kWh | 9000 | 20000 | | | | |
| | 1 | MEAS_2:2GENERA-1JIT1 | U2 GROSS OUTPUT MW (ANALOG) 1 ~ GENMW | MW | 1 | 2 | MW | | | | | | |
| | 6 | MEAS_2:2MSTBLT-1TE | U2 MAIN STEAM BOILER OUT LEFT | degF | 1 | 3 | degF | | | | | | |
| | 6 | MEAS_2:2MSTBRT-1TE | U2 MAIN STEAM BOILER OUT RIGHT | degF | 1 | 3 | degF | | | | | | |
| | 8 | MDCalc_LOSS_ACTUAL:THROTTLEP | THROTTLE STEAM PRESSURE CONTROLLABLE LOSS | PSIG | 1 | 4 | PSIG | 1600 | 2200 | | | | |
| | 11 | MEAS_2:2VLVPOS-1ZIT | U2 VLV POSITION | | 1 | 5 | | 0 | 150 | | | | |

**Figure 3-3 Unit 2 Unit Load from August 2016**

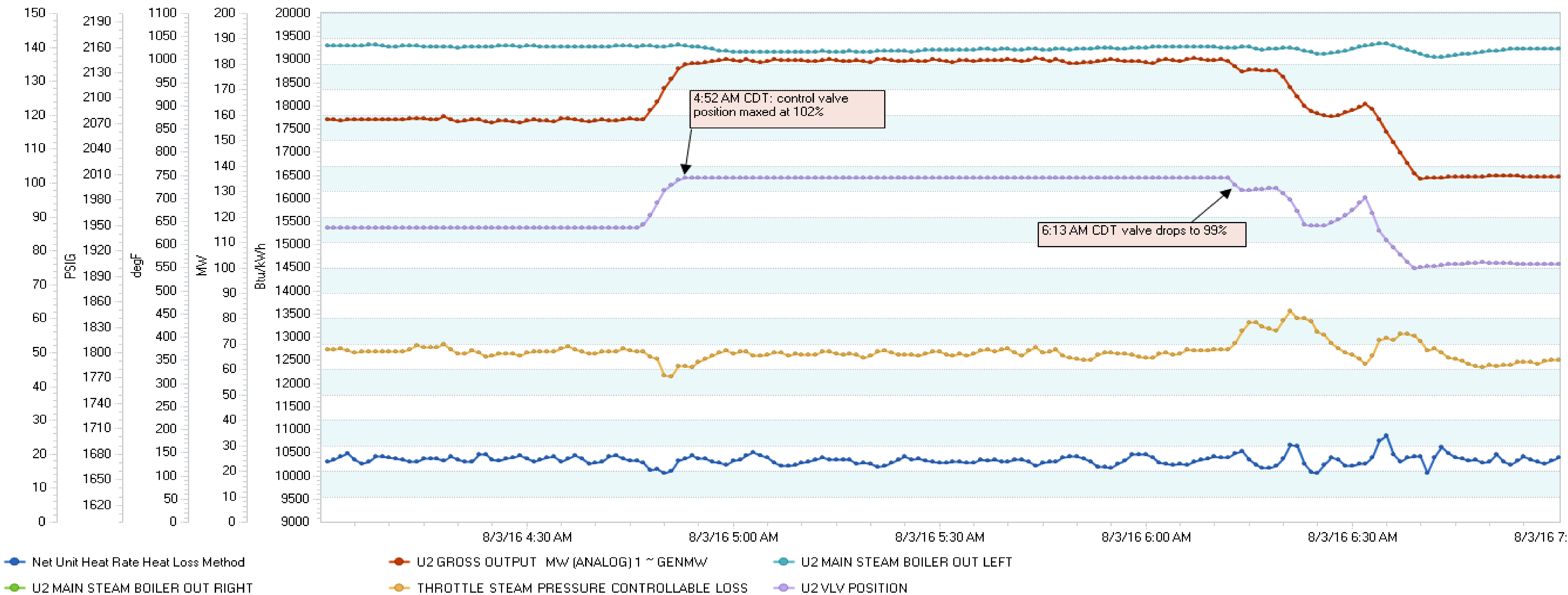



Clear Filter Row   Update Charts   Show Model Drilldown   Export

rend Duration: 2   Days   End: 08/04/2016 12:00 AM   Data Source: 1min

| w | Level | Tag Name | Tag Description | Tag Units | Chart | Axis | Axis Units | Axis Min | Axis Max | Last Y | Filter | Filter Min | Filter Max |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | 1 | | | | | | | | |
| ☑ | 0 | MDCalc_TURBIN:NUHR_HL | Net Unit Heat Rate Heat Loss Method | Btu/kWh | 1 | 1 | Btu/kWh | 9000 | 20000 | | ☐ | | |
| ☑ | 1 | MEAS_2:2GENERA-1JIT1 | U2 GROSS OUTPUT MW (ANALOG) 1 ~ GENMW | MW | 1 | 2 | MW | | | | ☐ | | |
| ☑ | 6 | MEAS_2:2MSTBLT-1TE | U2 MAIN STEAM BOILER OUT LEFT | degF | 1 | 3 | degF | | | | ☐ | | |
| ☑ | 6 | MEAS_2:2MSTBRT-1TE | U2 MAIN STEAM BOILER OUT RIGHT | degF | 1 | 3 | degF | | | | ☐ | | |
| ☑ | 8 | MDCalc_LOSS_ACTUAL:THROTTLEP | THROTTLE STEAM PRESSURE CONTROLLABLE LOSS | PSIG | 1 | 4 | PSIG | 1600 | 2200 | | ☐ | | |
| ☑ | 11 | MEAS_2:2VLVPOS-1ZIT | U2 VLV POSITION | | 1 | 5 | | 0 | 150 | | ☐ | | |

**Figure 3-4 Unit 2 Plant Operating Characteristics from August 2016**

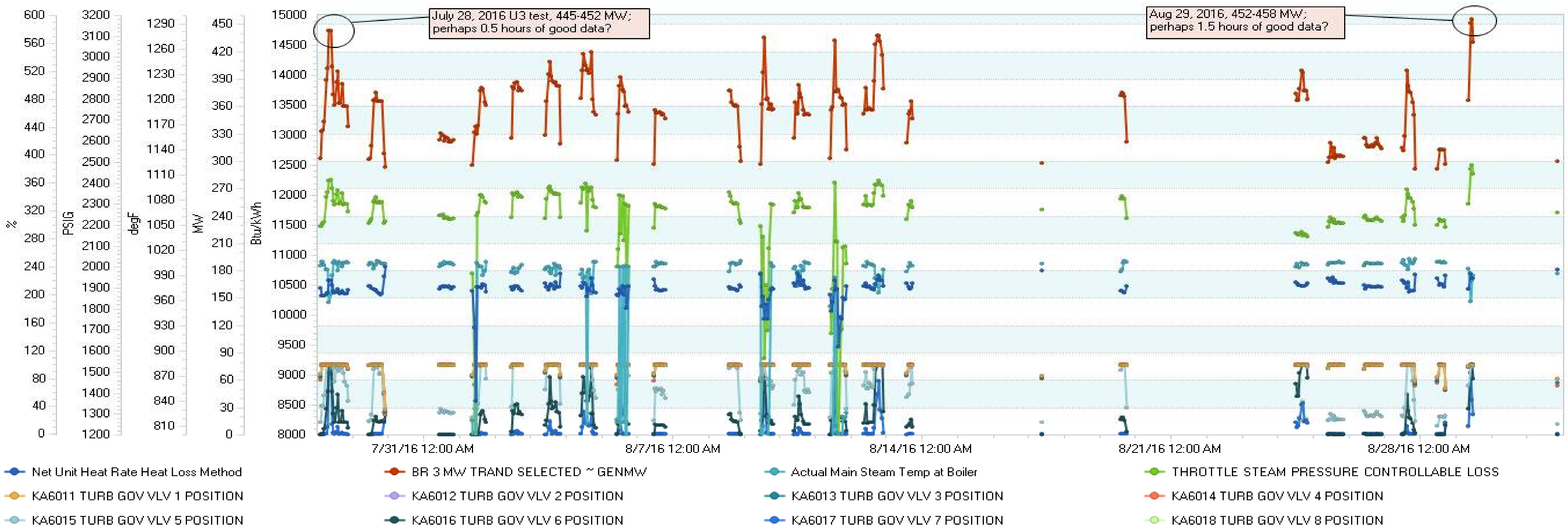



Clear Filter Row Update Charts Show Model Drilldown Export

end Duration: 3 Hours End: 08/03/2016 07:00 AM Data Source: 1min

| w | Level | Tag Name | Tag Description | Tag Units | Chart | Axis | Axis Units | Axis Min | Axis Max | Last Y | Filter | Filter Min | Filter Max |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | 1 | | | | | | | | |
| | 0 | MDCalc_TURBIN:NUHR_HL | Net Unit Heat Rate Heat Loss Method | Btu/kWh | 1 | 1 | Btu/kWh | 9000 | 20000 | | | | |
| | 1 | MEAS_2:2GENERA-1JIT1 | U2 GROSS OUTPUT MW (ANALOG) 1 ~ GENMW | MW | 1 | 2 | MW | | | | | | |
| | 6 | MEAS_2:2MSTBLT-1TE | U2 MAIN STEAM BOILER OUT LEFT | degF | 1 | 3 | degF | | | | | | |
| | 6 | MEAS_2:2MSTBRT-1TE | U2 MAIN STEAM BOILER OUT RIGHT | degF | 1 | 3 | degF | | | | | | |
| | 8 | MDCalc_LOSS_ACTUAL:THROTTLEP | THROTTLE STEAM PRESSURE CONTROLLABLE LOSS | PSIG | 1 | 4 | PSIG | 1600 | 2200 | | | | |
| | 11 | MEAS_2:2VLVPOS-1ZIT | U2 VLV POSITION | | 1 | 5 | | 0 | 150 | | | | |

**Figure 3-5 Unit 2 VWO Operation**

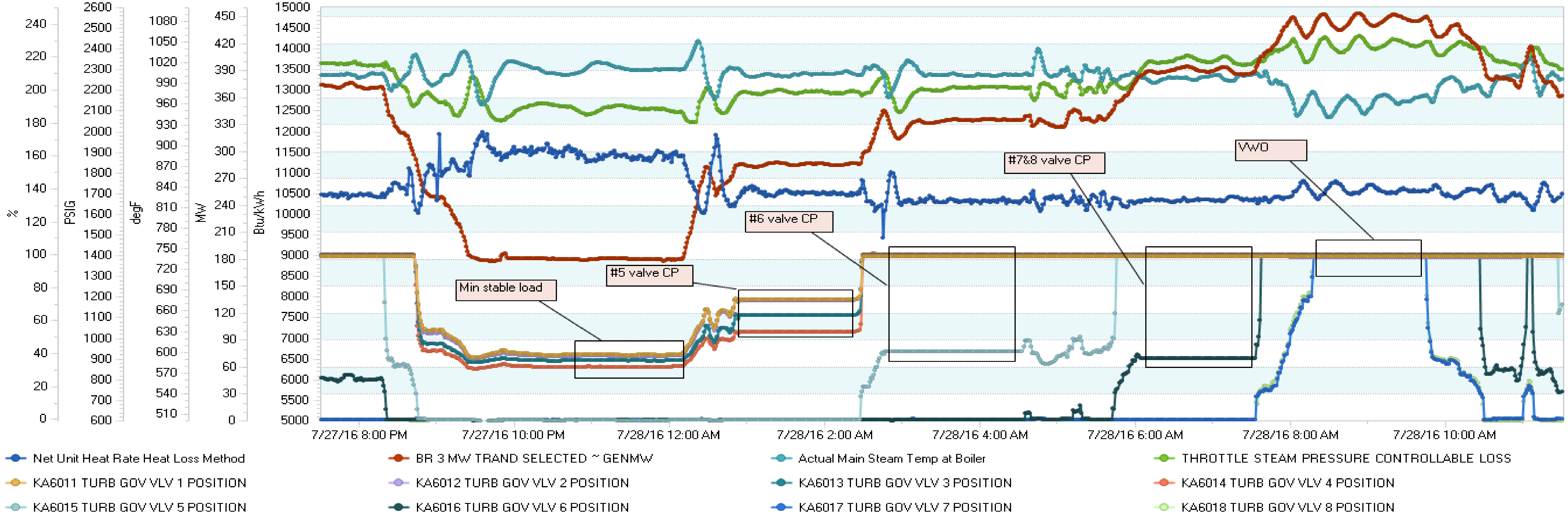



Clear Filter Row | Update Charts | Show Model Drilldown | Export

end Duration: 35 Days End: 09/01/2016 12:00 AM Data Source: 60min

| w | Level | Tag Name | Tag Description | Tag Units | Chart | Axis | Axis Units | Axis Min | Axis Max | Last Y | Filter | Filter Min | Filter Max |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | 1 | | | | | | | | |
| ☑ | 0 | MDCalc_TURBIN:NUHR_HL | Net Unit Heat Rate Heat Loss Method | Btu/kWh | 1 | 1 | Btu/kWh | 8000 | 15000 | | ☐ | | |
| ☑ | 1 | MEAS_3:3GENMWSELAI | BR 3 MW TRAND SELECTED ~ GENMW | MW | 1 | 2 | MW | 0 | 460 | | ☑ | 290 | |
| ☑ | 8 | MDCalc_LOSS_ACTUAL:MST | Actual Main Steam Temp at Boiler | degF | 1 | 3 | degF | 800 | 1300 | | ☐ | | |
| ☑ | 8 | MDCalc_LOSS_ACTUAL:THROTTLEP | THROTTLE STEAM PRESSURE CONTROLLABLE LOSS | PSIG | 1 | 4 | PSIG | 1200 | 3200 | | ☐ | | |
| ☑ | 12 | MEAS_3:3TURTCSGV1PFB | KA6011 TURB GOV VLV 1 POSITION | % | 1 | 5 | % | -1 | 600 | | ☐ | | |
| ☑ | 12 | MEAS_3:3TURTCSGV2PFB | KA6012 TURB GOV VLV 2 POSITION | % | 1 | 5 | % | -1 | 600 | | ☐ | | |
| ☑ | 12 | MEAS_3:3TURTCSGV3PFB | KA6013 TURB GOV VLV 3 POSITION | % | 1 | 5 | % | -1 | 600 | | ☐ | | |
| ☑ | 12 | MEAS_3:3TURTCSGV4PFB | KA6014 TURB GOV VLV 4 POSITION | % | 1 | 5 | % | -1 | 600 | | ☐ | | |
| ☑ | 12 | MEAS_3:3TURTCSGV5PFB | KA6015 TURB GOV VLV 5 POSITION | % | 1 | 5 | % | -1 | 600 | | ☐ | | |
| ☑ | 12 | MEAS_3:3TURTCSGV6PFB | KA6016 TURB GOV VLV 6 POSITION | % | 1 | 5 | % | -1 | 600 | | ☐ | | |
| ☑ | 12 | MEAS_3:3TURTCSGV7PFB | KA6017 TURB GOV VLV 7 POSITION | % | 1 | 5 | % | -1 | 600 | | ☐ | | |
| ☑ | 12 | MEAS_3:3TURTCSGV8PFB | KA6018 TURB GOV VLV 8 POSITION | % | 1 | 5 | % | -1 | 600 | | ☐ | | |

**Figure 3-6 Unit 3 Plant Data from Data from July and August 2016**

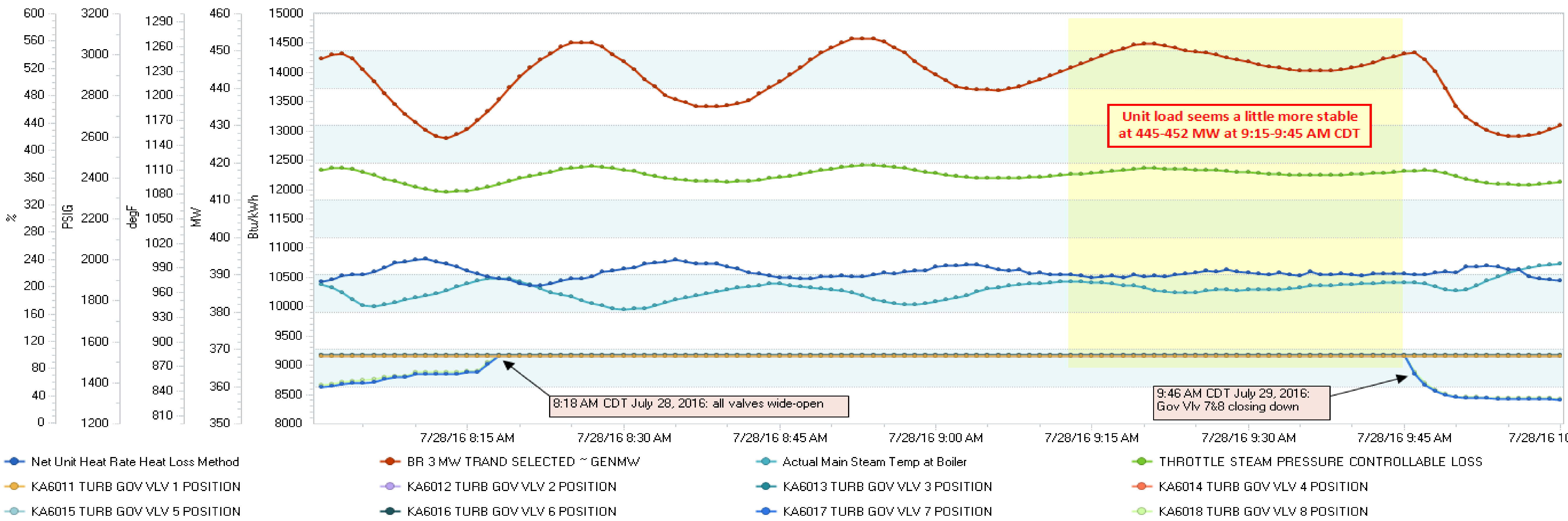



Clear Filter Row | Update Charts | Show Model Drilldown | Export

end Duration: 16 Hours End: 07/28/2016 11:30 AM Data Source: 1min

| w | Level | Tag Name | Tag Description | Tag Units | Chart | Axis | Axis Units | Axis Min | Axis Max | Last Y | Filter | Filter Min | Filter Max |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | 1 | | | | | | | | |
| ☑ | 0 | MDCalc_TURBIN:NUHR_HL | Net Unit Heat Rate Heat Loss Method | Btu/kWh | 1 | 1 | Btu/kWh | 5000 | 15000 | | ☐ | | |
| ☑ | 1 | MEAS_3:3GENMWSELAI | BR 3 MW TRAND SELECTED ~ GENMW | MW | 1 | 2 | MW | 0 | 460 | | ☐ | | |
| ☑ | 8 | MDCalc_LOSS_ACTUAL:MST | Actual Main Steam Temp at Boiler | degF | 1 | 3 | degF | 500 | 1100 | | ☐ | | |
| ☑ | 8 | MDCalc_LOSS_ACTUAL:THROTTLEP | THROTTLE STEAM PRESSURE CONTROLLABLE LOSS | PSIG | 1 | 4 | PSIG | 600 | 2600 | | ☐ | | |
| ☑ | 12 | MEAS_3:3TURTCSGV1PFB | KA6011 TURB GOV VLV 1 POSITION | % | 1 | 5 | % | -1 | 250 | | ☐ | | |
| ☑ | 12 | MEAS_3:3TURTCSGV2PFB | KA6012 TURB GOV VLV 2 POSITION | % | 1 | 5 | % | -1 | 250 | | ☐ | | |
| ☑ | 12 | MEAS_3:3TURTCSGV3PFB | KA6013 TURB GOV VLV 3 POSITION | % | 1 | 5 | % | -1 | 250 | | ☐ | | |
| ☑ | 12 | MEAS_3:3TURTCSGV4PFB | KA6014 TURB GOV VLV 4 POSITION | % | 1 | 5 | % | -1 | 250 | | ☐ | | |
| ☑ | 12 | MEAS_3:3TURTCSGV5PFB | KA6015 TURB GOV VLV 5 POSITION | % | 1 | 5 | % | -1 | 250 | | ☐ | | |
| ☑ | 12 | MEAS_3:3TURTCSGV6PFB | KA6016 TURB GOV VLV 6 POSITION | % | 1 | 5 | % | -1 | 250 | | ☐ | | |
| ☑ | 12 | MEAS_3:3TURTCSGV7PFB | KA6017 TURB GOV VLV 7 POSITION | % | 1 | 5 | % | -1 | 250 | | ☐ | | |
| ☑ | 12 | MEAS_3:3TURTCSGV8PFB | KA6018 TURB GOV VLV 8 POSITION | % | 1 | 5 | % | -1 | 250 | | ☐ | | |

**Figure 3-7 Unit 3 2016 Capability Test Run Data**




| w | Level | Tag Name | Tag Description | Tag Units | Chart | Axis | Axis Units | Axis Min | Axis Max | Last Y | Filter | Filter Min | Filter Max |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | 1 | | | | | | | | |
| ☑ | 0 | MDCalc_TURBIN:NUHR_HL | Net Unit Heat Rate Heat Loss Method | Btu/kWh | 1 | 1 | Btu/kWh | 8000 | 15000 | | ☐ | | |
| ☑ | 1 | MEAS_3:3GENMWSELAI | BR 3 MW TRAND SELECTED ~ GENMW | MW | 1 | 2 | MW | 350 | 460 | | ☐ | | |
| ☑ | 8 | MDCalc_LOSS_ACTUAL:MST | Actual Main Steam Temp at Boiler | degF | 1 | 3 | degF | 800 | 1300 | | ☐ | | |
| ☑ | 8 | MDCalc_LOSS_ACTUAL:THROTTLEP | THROTTLE STEAM PRESSURE CONTROLLABLE LOSS | PSIG | 1 | 4 | PSIG | 1200 | 3200 | | ☐ | | |
| ☑ | 12 | MEAS_3:3TURTCSGV1PFB | KA6011 TURB GOV VLV 1 POSITION | % | 1 | 5 | % | -1 | 600 | | ☐ | | |
| ☑ | 12 | MEAS_3:3TURTCSGV2PFB | KA6012 TURB GOV VLV 2 POSITION | % | 1 | 5 | % | -1 | 600 | | ☐ | | |
| ☑ | 12 | MEAS_3:3TURTCSGV3PFB | KA6013 TURB GOV VLV 3 POSITION | % | 1 | 5 | % | -1 | 600 | | ☐ | | |
| ☑ | 12 | MEAS_3:3TURTCSGV4PFB | KA6014 TURB GOV VLV 4 POSITION | % | 1 | 5 | % | -1 | 600 | | ☐ | | |
| ☑ | 12 | MEAS_3:3TURTCSGV5PFB | KA6015 TURB GOV VLV 5 POSITION | % | 1 | 5 | % | -1 | 600 | | ☐ | | |
| ☑ | 12 | MEAS_3:3TURTCSGV6PFB | KA6016 TURB GOV VLV 6 POSITION | % | 1 | 5 | % | -1 | 600 | | ☐ | | |
| ☑ | 12 | MEAS_3:3TURTCSGV7PFB | KA6017 TURB GOV VLV 7 POSITION | % | 1 | 5 | % | -1 | 600 | | ☐ | | |
| ☑ | 12 | MEAS_3:3TURTCSGV8PFB | KA6018 TURB GOV VLV 8 POSITION | % | 1 | 5 | % | -1 | 600 | | ☐ | | |

**Figure 3-8 Unit 3 VWO Unit Characteristics**

### 3.3.3 Detailed Fuel Switching Impact Analysis Results

There were three primary areas of focus for the coal to gas conversion study for the three Brown units:

- The capability of the boilers to achieve their steaming rates and conditions.
- The impact upon net plant heat rate and boiler efficiency.
- The impact of other fuel-related equipment at the power plant, such as fans and emissions control systems.

Each of these items will be addressed in turn.

#### 3.3.3.1 Boiler Steaming Capability

Several iterations of modeling were performed with the Vista program, with initial evaluations focused solely upon the boiler, and the final evaluations including a high-pressure turbine and feedwater heater model which was linked into the boiler model in order to better calculate the impact to cold and hot reheat steam conditions as a result of changes in the main steam conditions.

Unit 1 is a wall-fired that has a split backpass to assist in gas bias between the main steam and reheat steam circuits. The split backpass was modeled within Vista, and gas bias was altered by the model from the main steam side to the reheat side to try to converge upon a stable heat transfer solution. The steam generator model had great difficulty converging upon a heat transfer solution which that would provide safe and stable boiler operation at 100% gas. This indicates that unit derates may be expected without some boiler modifications, such as heat transfer surface area changes.

The result of this boiler modeling revealed that the Unit 1 main steam temperature at full load was expected to decrease from 1,001 °F with coal to 800 °F with natural gas. The reheat steam temperature was predicted to undergo similar reductions, from a baseline of 1,017 °F with coal to 835 °F with natural gas. At the current predicted temperatures, Unit 1 is likely to put its LP turbine at-risk for high levels of condensation, and even if the gross load loss was recoverable, the unit may still require operation at a derated steam flow.

It was noted during modeling that Unit 1's excess oxygen at full load increased significantly since the 2011 calibration – a baseline value with coal of 5.21% was given by the performance tag "Economizer exit $O_2$ for Controllable Loss." This created a significant difference in the Unit 1 results from 2011, and cascaded through to the gas results for this analysis. The excess $O_2$ points from the historian are shown in Figure 3-9.

Figure 3-10 shows the long-term excess $O_2$ readings from Brown Unit 1 at high load points.


**Figure 3-9 Unit 1 Full Load Boiler Outlet Oxygen Content**

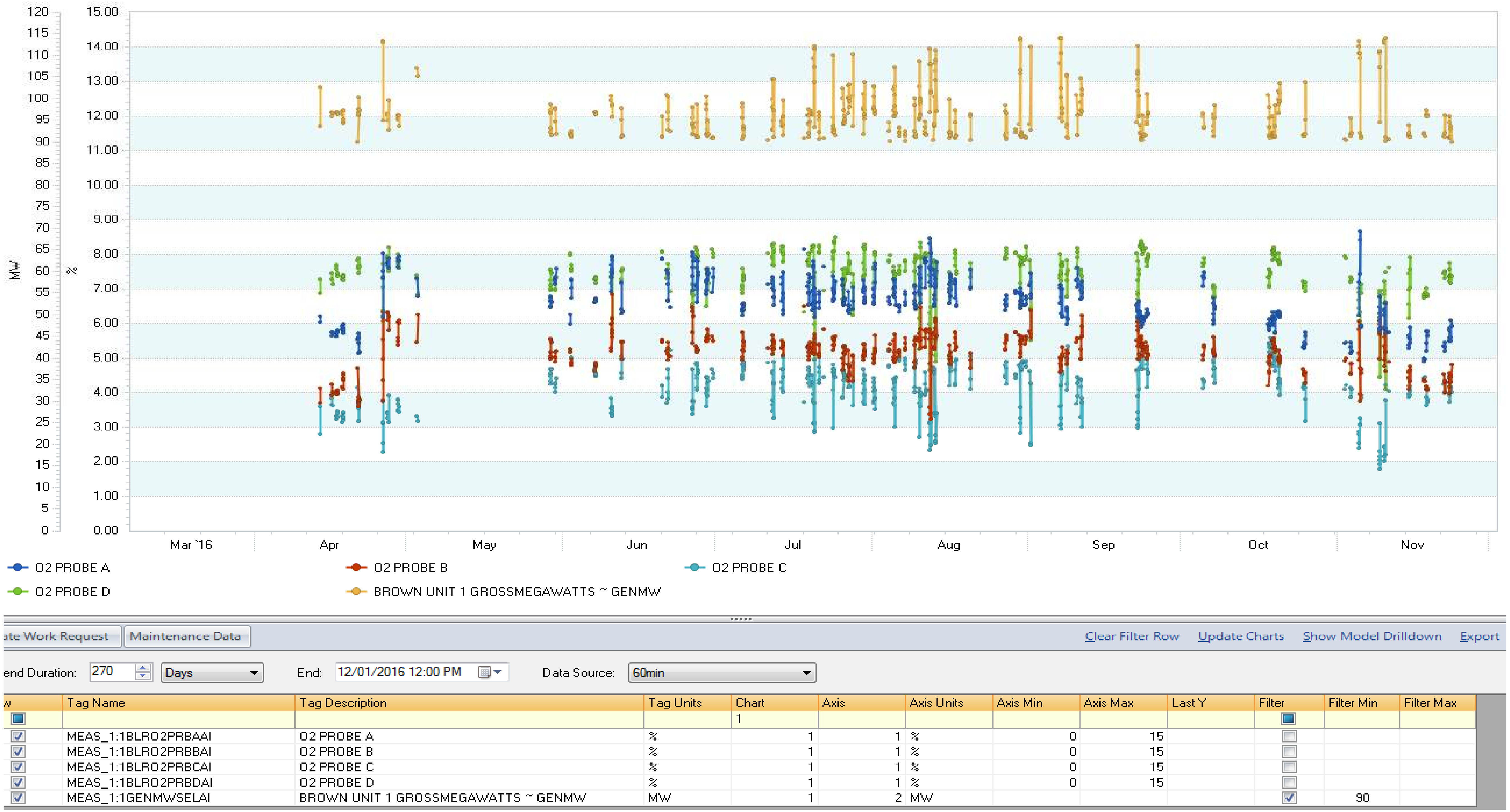



**Figure 3-10** **Unit 1 Full Load Boiler Outlet Oxygen Content Variation Over Time**

For Unit 1, no OEM heat rate curves were available to predict the impact on gross load as a function of the depressed main and reheat steam temperatures. Black & Veatch boiler modelers therefore used PTC 6.1-1984 Figures A9 and A11 to determine the potential heat rate and gross output impacts. The predicted reduction in gross load was 3.5 MW due to reduced main steam energy and 9.3 MW due to reduced reheat steam energy, for a total loss of 12.8 MW at full load.

Unit 2 is a tangential-fired unit with burner tilts, and the burner tilt capability was modeled within the Vista program and varied by the program to try to balance heat transfer between the main and reheat steam during natural gas combustion. The result of this boiler modeling revealed that the Unit 2 main steam temperature at full load was expected to decrease from 1,020 °F with coal to 1,000 °F with natural gas. The reheat steam temperature was predicted to undergo similar reductions, from a baseline of 1,012 °F with coal to 977 °F with natural gas. To achieve these temperatures the burners were tilted from a baseline condition of -20° downward with coal, to +30° upward with natural gas.

For Unit 2, no OEM heat rate curves were available to predict the impact on gross load as a function of the depressed main and reheat steam temperatures. Similar to Unit 1, Black & Veatch boiler modelers used PTC 6.1-1984 Figures A9 and A11 to determine the potential heat rate and gross output impacts. The predicted reduction in gross load was 0.60 MW due to reduced main steam energy and 2.9 MW due to reduced reheat steam energy, for a total loss of 3.5 MW at full load.

Like Unit 2, Unit 3 is a tangential-fired unit with burner tilts, and the burner tilt capability was modeled within the Vista program and varied by the program to try to balance heat transfer between the main and reheat steam during natural gas combustion. It was noted by boiler modelers that the main steam temperatures were reduced significantly from the 2011 model values, a function of the actual operation of the unit during the time at which the baseline data was collected. Figure 3-11 displays a plot of Unit 3 main steam temperatures over the time period used to calibrate model results.

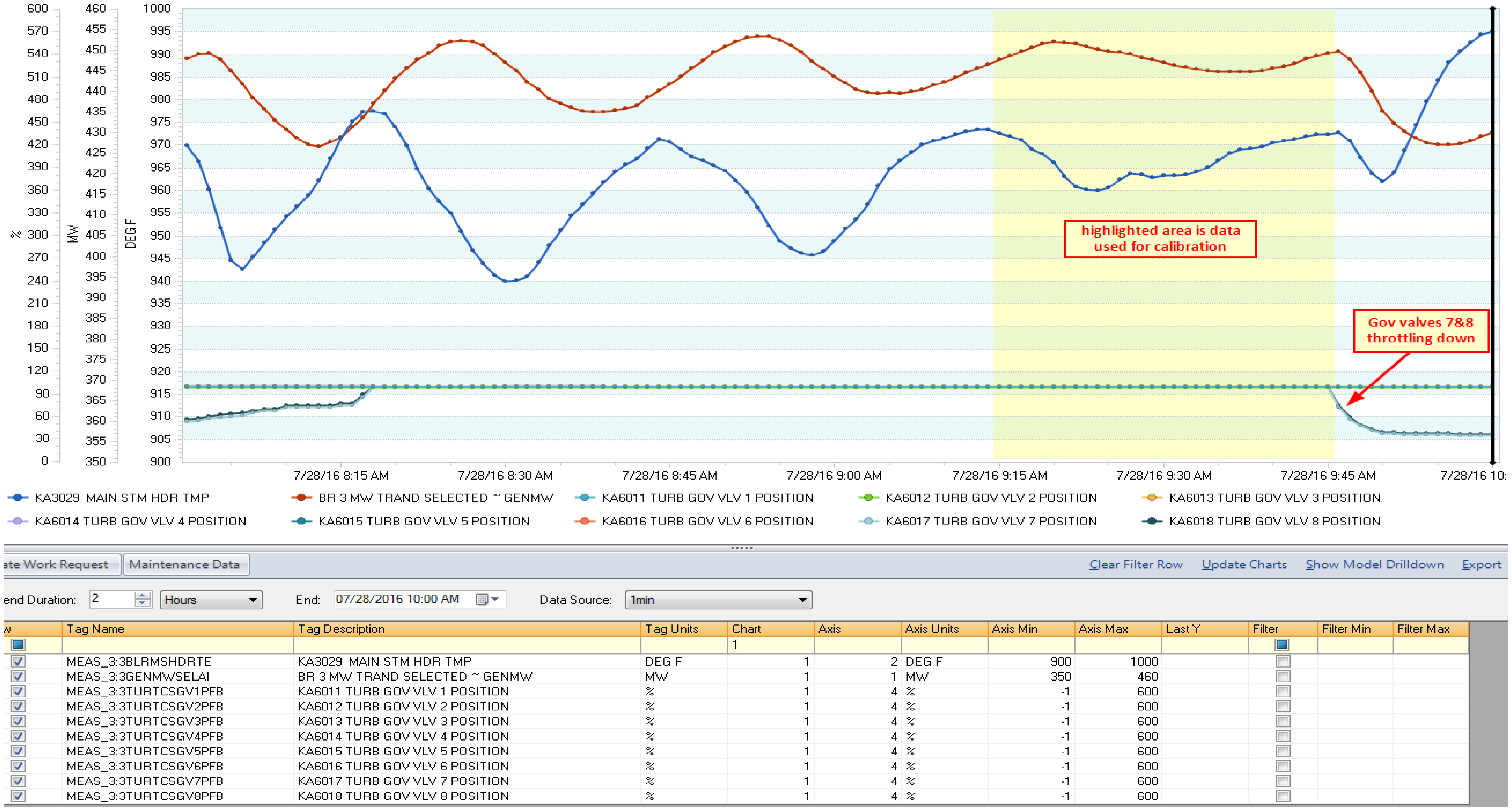



**Figure 3-11 Unit 3 Main Steam Temperature Variation over Time**

The result of this boiler modeling revealed that the Unit 3 main steam temperature at full load was expected to decrease from 968 °F with coal to 916 °F with natural gas. The reheat steam temperature was predicted to undergo similar reductions, from a baseline of 997 °F with coal to 910 °F with natural gas. To achieve these temperatures the burners were tilted from a baseline condition of +8° upward with coal, to +30° upward with natural gas.

For Unit 3 there were specific OEM heat rate curves that were available to predict the impact on gross load as a function of the depressed main and reheat steam temperatures. The predicted reduction in gross load was 4.9 MW due to reduced main steam energy and 18.8 MW due to reduced reheat steam energy, for a total loss of 23.7 MW at full load.

An analysis was done to estimate the amount of increase in the fuel burn rate which would be needed in order to remove the derates from each of the three units. Unit 1 would be required to increase the fuel burn rate the greatest proportion relative to its full-load heat input, an additional 148 MBtu/hr to recover the lost load. Unit 2 would be required to increase the fuel burn rate an additional 35 MBtu/hr to recover its lost load, and Unit 3 would be required to increase the fuel burn an additional 255 MBtu/hr to recover its lost load. These represent an increase in the fuel burn rates of 11.7%, 1.9%, and 5.3% for Units 1, 2, and 3 respectively.

#### 3.3.3.2 Impact on Net Plant Heat Rate and Efficiency

In each of the cases evaluated by the Vista program, the goal of the modeling was to try to hold gross power output constant. Both the gross and the net power were calibrated from the plant data which was collected, and the potential net power was expected to “float” from case to case depending upon equipment loading and duty cycles. When burning 100 percent natural gas it was expected that the net power would increase, as there will be no power demand for the coal handling system, ash handling systems, mills, ESP, and scrubber. There were also auxiliary power savings from the pumps and limestone handling equipment for the common wet limestone FGD system, since Units 1, 2 and 3 will be bypassing the WFGD system while operating on natural gas. Primary air fans were also eliminated in the Vista modeling, however it is possible that primary air fans could be utilized to support combustion by supplying additional air to the boiler in parallel with the forced draft fans.

One significant impact of switching to 100 percent natural gas combustion is an increase in the latent heat losses of combustion resulting from the large amount of hydrogen in the natural gas fuel. However, unburned carbon losses will be greatly decreased due to the ease of combustion of natural gas. Sensible heat losses may increase or decrease, depending upon the impact to boiler heat transfer from the switch to gas combustion, which makes boiler modeling an essential part of every coal to gas conversion analysis.

#### 3.3.3.3 Impact on Other Fuel-related Equipment

It is expected that coal handling, ash handling, ESP, and scrubber-related systems will not be in operation with 100 percent natural gas combustion. Primary air fans may be in operation if they are re-purposed to help supply combustion air to the boiler – however, all Vista modeling was conducted assuming that the primary air fans were not part of the final natural gas-firing configuration. Air heater leakage was held constant across all cases, and a value of 12% was used as an assumed value based upon input from LG&E KU Vista modeling personnel, due to a lack of better values from air heater leakage testing. A summary of the impacts upon the boiler performance unit efficiency and heat rate, and individual equipment performance is shown in Table 3-4.

**Table 3-4 Performance Results**

| ULTIMATE FUEL ANALYSIS, WET BASIS | UNIT 1 COAL | UNIT 1 GAS | UNIT 2 COAL | UNIT 2 GAS | UNIT 3 COAL | UNIT 3 GAS | NOTES/REFERENCES |
|---|---|---|---|---|---|---|---|
| **UNIT CHARACTERISTICS** | | | | | | | |
| Target Gross Turbine Generator Load, MW | 109.43 | 109.43 | 182.03 | 182.03 | 448.03 | 448.03 | |
| Actual Gross Turbine Generator Load, MW | 109.43 | 96.63 | 182.03 | 178.53 | 448.03 | 424.33 | |
| Turbine Derate, MW | 0 | 12.80 | 0 | 3.50 | 0 | 23.70 | |
| Turbine Derate, percentage | NA | 11.7 | NA | 1.9 | NA | 5.29 | |
| Net Power (assuming full load was achieved) | 102.37 | 106.36 | 167.41 | 173.36 | 426.59 | 434.85 | |
| Boiler Efficiency, % (HHV) | 85.29 | 83.35 | 86.33 | 83.31 | 87.36 | 84.36 | |
| Net Plant Hear Rate, Btu/kWh (HHV) | 11,408 | 11,866 | 10,542 | 10,632 | 10,696 | 11,086 | |
| Boiler Heat Input, MBtu/hr (HHV) | 1167.86 | 1262.14 | 1764.91 | 1843.15 | 4562.77 | 4820.68 | |
| Coal Flow Rate, ton/hr | 51.71 | | 77.93 | | 202.57 | | |
| Natural Gas Flow Rate, kcfm | | 19.77 | | 38.87 | | 75.50 | |
| Main Steam Outlet Temperature, °F | 1,002 | 800 | 1,020 | 1,000 | 968 | 916 | |
| Hot Reheat Steam Outlet Temperature, °F | 1,017 | 835 | 1,012 | 977 | 997 | 910 | |
| Air Heater Leakage, % | 12 | 12 | 12 | 12 | 12 | 12 | |
| Excess Air (EA), % | 34.4 | 12.0 | 16.6 | 5.8 | 14.1 | 8.1 | |
| **Air Heater Air Inlet Conditions** | | | | | | | |
| Combustion Air Temperature, °F | 91.3 | 91.3 | 76.7 | 76.7 | 98.8 | 98.8 | |
| Combustion Air Pressure, in. w.g. | 7.0 | 5.8 | 14.7 | 13.2 | 12.4 | 12.9 | |
| Combustion Air Mass Flow Rate, lb/h | 1,088,960 | 934,109 | 1,334,982 | 1,279,150 | 3,677,406 | 3,843,065 | |
| Volumetric Combustion Air Flow Rate, acfm | 258,568 | 222,423 | 302,083 | 290,374 | 879,019 | 917,478 | |

| ULTIMATE FUEL ANALYSIS, WET BASIS | UNIT 1 COAL | UNIT 1 GAS | UNIT 2 COAL | UNIT 2 GAS | UNIT 3 COAL | UNIT 3 GAS | NOTES/REFERENCES |
|---|---|---|---|---|---|---|---|
| **Economizer Gas Outlet Conditions** | | | | | | | |
| Flue Gas Temperature, °F | 642.0 | 567.3 | 718.9 | 699.5 | 746.5 | 714.8 | |
| Flue Gas Pressure, in. w.g. | -7.0 | -4.7 | -4.4 | -3.7 | -5.9 | -5.6 | |
| Flue Gas Mass Flow Rate, lb/h | 1,303,715 | 1,091,663 | 1,730,414 | 1,499,793 | 4,365,786 | 4,048,417 | |
| Volumetric Flue Gas Flow Rate, acfm | 622,917 | 513,331 | 872,104 | 792,772 | 2,274,423 | 2,190,279 | |
| **Air Heater Gas Outlet Conditions** | | | | | | | |
| Flue Gas Temperature, °F | 355.3 | 316.5 | 340.7 | 322.0 | 317.2 | 292.1 | |
| Flue Gas Pressure, in. w.g. | -11.3 | -7.5 | -9.2 | -7.7 | -22.0 | -20.2 | |
| Flue Gas Mass Flow Rate, lb/h | 1,460,145 | 1,222,663 | 1,938,037 | 1,679,768 | 4,889,894 | 4,534,227 | |
| Volumetric Flue Gas Flow Rate, acfm | 523,233 | 436,151 | 673,619 | 602,498 | 1,717,339 | 1,625,680 | |

## 3.4 BOILER MODIFICATIONS

### 3.4.1 Boiler

At this time, detailed performance modeling of the boiler heat transfer surfaces has not been performed as such modeling is beyond the scope of this analysis. Based on previous natural gas conversion studies by Black & Veatch, it is likely that there will be some heat transfer surface modifications required to maintain full load output due to the shift in balance of heat transfer from radiative to convective surfaces. Based on previous projects, the cost of these modifications may approach $6 million on Unit 1, $7 million on Unit 2, and $10 million on Unit 3. These costs are for reference, have not been included in the cost estimate, and will need to be verified during detailed design if implemented. If surface modifications are determined to be necessary and are not performed, the maximum gross unit output would be reduced by approximately 13 MW for Unit 1, 4 MW for Unit 2, and 24 MW for Unit 3.

### 3.4.2 Burners, Igniters, and Flame Scanners

RFQs were sent to six (6) burner manufacturers of which five (5) proposals were received for this study. Based on these offerings, sixteen (16) replacement burners will be furnished for Unit 1 and will consist of a ring header style gas burner which will replace the existing coal fired burners. Multiple natural gas spuds from the ring header will extend into the furnace through the annulus of the burner. On Unit 2 and Unit 3, the existing coal nozzles will be removed and new natural gas burners will be installed in the fuel air buckets.

The existing oil ignition system will be replaced with a new natural gas ignition system so that oil will no longer be required on the units. All piping, valves and instruments associated with the existing oil ignition system will be removed.

The existing IR flame scanners will be replaced with new IR/UV or VIS/IR/UV scanners capable of detecting flames from the new natural gas fuel.

A side-by-side comparison of the received quotes along with the copy of the quotes is included for reference in Appendix C.

## 3.5 COMBUSTION AIR SYSTEM

All three units are ideally configured to accommodate the removal of the PA system and the pulverizers for natural gas firing. All three units are equipped with FD fans sized for all of the combustion air, and all three units are equipped with bisector air heaters. Downstream of the air heaters, the combustion air flow splits. The secondary air travels to the windbox and the primary air travels to the mills. Unit 1 has hot PA fans (located downstream of the air heater) with vertical mills, and Unit 2 and Unit 3 have exhauster mills (the combustion air fan is an integral component of the mill).

For natural gas firing, the mills and PA fans will be taken out of service (abandoned in place). The portion of the combustion air traveling to the mills will be blocked off such that all combustion air travels to the windbox. These changes are very easily accomplished in the combustion air ductwork. Changes to the windbox size to accommodate the additional combustion air are not anticipated at this time. The FD fans will continue to operate as they currently do, without modifications. No changes are required to the air heaters to accommodate the removal of the PA system. These combustion air system modifications for natural gas firing can easily be reversed for a future return to coal firing, if the plant determines to do so.

### 3.5.1 Forced Draft Fan Analysis

#### 3.5.1.1 Unit 1 Forced Draft Fan Analysis

The existing combustion air draft system on Unit 1 consists of two FD fans. The electric motors for each FD fan have a maximum operating nominal speed of 1,200 revolutions per minute (rpm). The nameplate horsepower rating of the FD fan motors is 350 horsepower. The service factor of the motors is unknown. They operate at a nominal voltage of 2,400 volts. Primary flow control of the FD fans is accomplished by the use of fluid drives in between the fans and motors allowing for variable speed flow control. The FD fans are double inlet centrifugal fans with a maximum speed capability of 1,157 rpm due to the fluid drives. The FD fans are a Westinghouse Sturtevant design, Model 125 TV DES 12.

The Unit 1 FD fan analysis in Table 3-5 summarizes the current operating conditions firing coal and the anticipated conditions following a switch to natural gas.

**Table 3-5 Unit 1 Forced Draft Fan Analysis**

| UNIT 1 FD FAN PERFORMANCE (PER FAN) | COAL | NATURAL GAS |
|---|---|---|
| Fan Flow Rate, acfm | 148,185 | 126,734 |
| Fan Static Pressure Rise, in. $H_2O$. | 6.9 | 5.9 |
| Temperature, °F | 91 | 91 |
| Flow Margin, % | 6.8 | 20.3 |
| Pressure Margin, % | 10.8 | 25.3 |

FD fans margins are expected to improve with natural gas due to lower boiler excess oxygen required to sustain stable combustion. Black & Veatch concluded that no modifications to the Unit 1 FD fans are required for the natural gas conversion.

#### 3.5.1.2 Unit 2 Forced Draft Fan Analysis

The existing combustion air draft system on Unit 2 consists of two FD fans. The electric motors for each FD fan have a maximum operating nominal speed of 1,200 rpm. The nameplate horsepower rating of the FD fan motors is approximately 1,400 horsepower. The service factor of the motors is unknown. They operate at a nominal voltage of 2,400 volts. Primary flow control of the FD fans is accomplished by the use of fluid drives in between the fans and motors allowing for variable speed flow control. The FD fans are double inlet centrifugal fans with a maximum speed capability of 1,160 rpm due to the fluid drives. The FD fans are a Westinghouse Sturtevant design, Model 2382. These FD fans were originally designed to service Unit 2 as a FD unit. Unit 2 is now a balanced draft unit.

The Unit 2 FD fan analysis in Table 3-6 summarizes the current operating conditions firing coal and the anticipated conditions following a switch to natural gas.

**Table 3-6 Unit 2 Forced Draft Fan Analysis**

| UNIT 2 FD FAN PERFORMANCE (PER FAN) | COAL | NATURAL GAS |
|---|---|---|
| Fan Flow Rate, acfm | 178,686 | 169,015 |
| Fan Static Pressure Rise, in. $H_2O$. | 14.7 | 13.2 |
| Temperature, °F | 77 | 77 |
| Flow Margin, % | 20.6 | 24.9 |
| Pressure Margin, % | 36.9 | 43.5 |

FD fans margins are expected to improve with natural gas due to lower boiler excess oxygen required to sustain stable combustion. Black & Veatch concluded that no modifications to the Unit 2 FD fans are required for the natural gas conversion.

### 3.5.1.3 Unit 3 Forced Draft Fan Analysis

The existing combustion air draft system on Unit 3 consists of two FD fans. The electric motors for each FD fan have a maximum operating nominal speed of 1,084 rpm. The nameplate horsepower rating of the FD fan motors is approximately 5,175 horsepower. The service factor of the motors is unknown. Primary flow control of the FD fans is accomplished by the use of fluid drives in between the fans and motors allowing for variable speed flow control. The FD fans are double inlet centrifugal fans with a maximum speed capability of 1,084 rpm due to the fluid drives.

The Unit 3 FD fan analysis in Table 3-7 summarizes the current operating conditions firing coal and the anticipated conditions following a switch to natural gas.

**Table 3-7 Unit 3 Forced Draft Fan Analysis**

| UNIT 3 FD FAN PERFORMANCE (PER FAN) | COAL | NATURAL GAS |
|---|---|---|
| Fan Flow Rate, acfm | 507,670 | 522,975 |
| Fan Static Pressure Rise, in. $H_2O$. | 12.5 | 13.0 |
| Temperature, °F | 99 | 99 |
| Flow Margin, % | 14.2 | 11.7 |
| Pressure Margin, % | 20.3 | 17.1 |

Plant data collected for Unit 3 indicated that the unit operates at much lower oxygen setting of 2.6% when firing coal compared to both Unit 1 and 2 which runs at 5.2% and 3% excess oxygen, respectively. The allowable reduction in boiler excess oxygen when firing natural gas will be comparably less for Unit 3 which resulted in a slight reduction in FD fan margin. However, Unit 3 FD fans have sizeable margin, and Black & Veatch concluded that no modifications to the Unit 3 FD fans are required for the natural gas conversion.

## 3.6 FLUE GAS SYSTEM

Since natural gas has no ash and negligible sulfur compared to coal, it is assumed that neither the ESPs (Unit 1 and Unit 2), nor the baghouse for Unit 3, nor the common WFGD will be required to reduce emissions from the flue gas following the conversion. The ESPs and baghouse are to be decommissioned in place and the internals removed if desired. The cost for removal of the internals has not been included in the cost estimate. Some of the ESP fields may need to remain energized for a period of time following the natural gas conversion to capture residual coal ash remaining in the equipment and ductwork. If the plant elects to permanently switch to natural gas, the internals of the ESP can be removed to further reduce system pressure drop.

Flue gas from all three units will be routed to the existing Unit 3 original stack to optimize usage of existing gas duct, minimize real-estate usage, and reduce construction cost. Flue gas on Unit 2 will be permanently bypassed around the FGD following a conversion to natural gas, utilizing the existing Unit 2 bypass duct to the Unit 3 original stack. Flue gas from Unit 1 will be tapped into the Unit 2 FGD bypass duct to avoid construction cost of a new Unit 1 bypass duct to the Unit 3 original stack. The duct design tie-in would require further detailed flow modeling to ensure a smooth transition via turning vanes or increasing the number of duct bends. Unit 2 FGD bypass duct will be capable of handling flue gas flow from Unit 1 and Unit 2 using existing ID fans. Figure 3-12 shows the duct tie-in between Unit 1 and Unit 2 to the existing Unit 2 bypass duct.

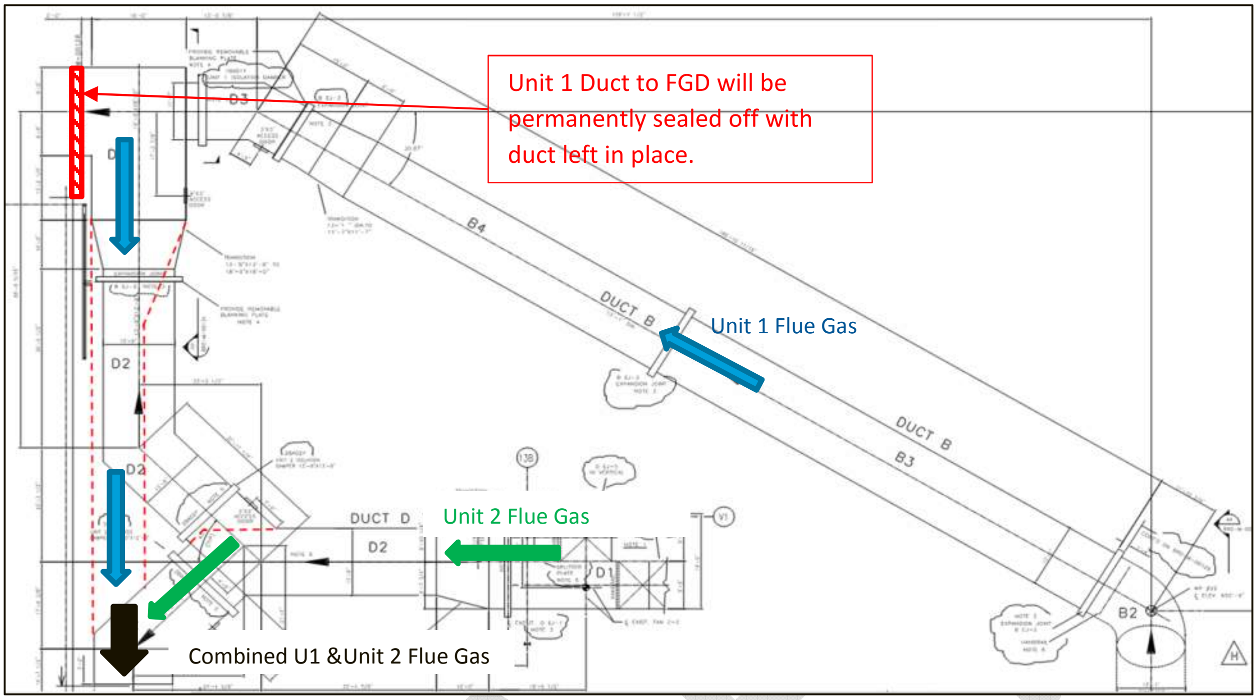



**Figure 3-12 Unit 1 and Unit 2 Flue Gas Duct to Unit 3 Original Stack**

Flue gas from Unit 3 ID fans discharge will be directed to 90 degree elbow followed by a vertical rise as shown in Figure 3-13. Flue gas from both Unit 3 ID fans would then be combined and routed across to Unit 3 original stack as shown in Figure 3-14.

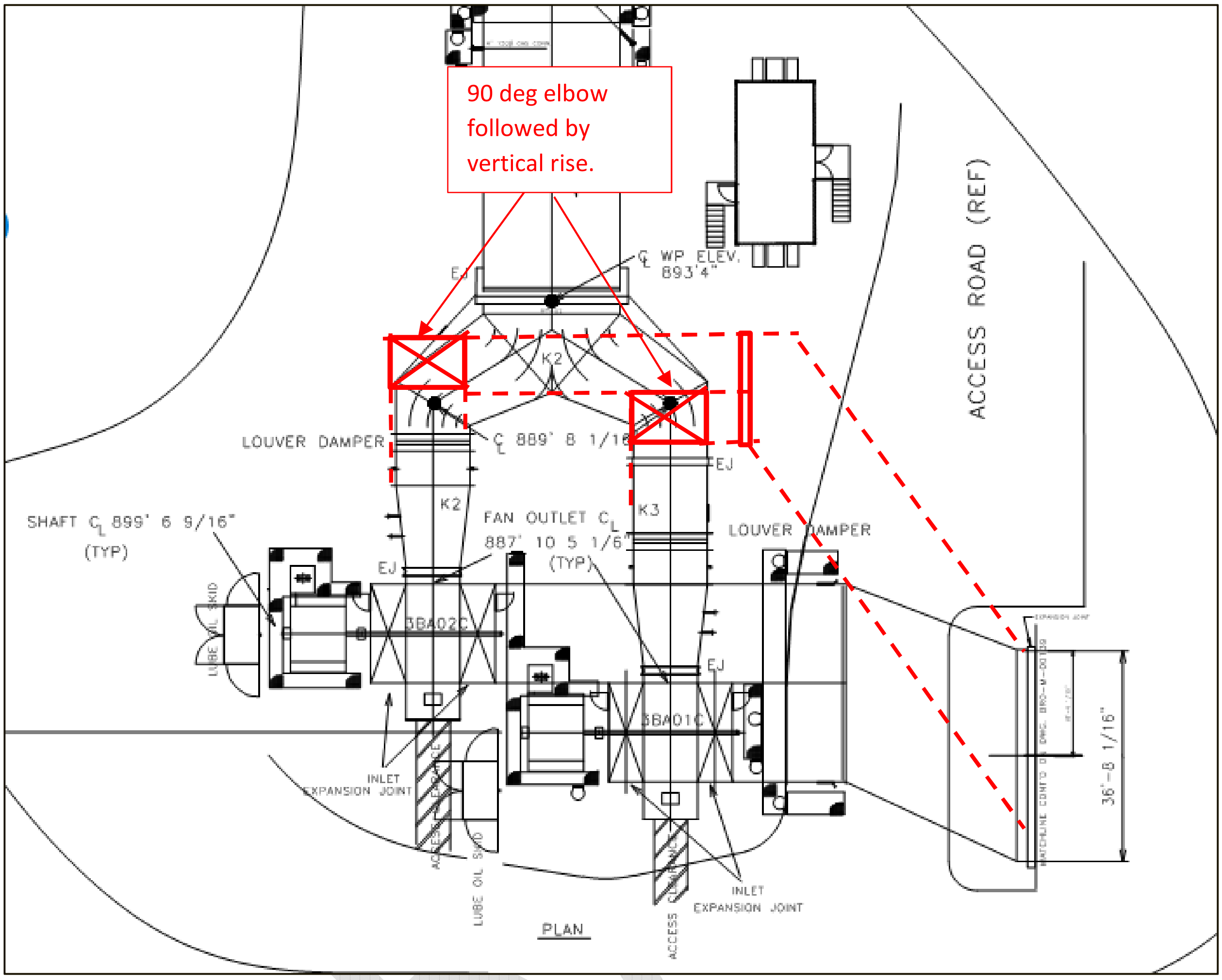



Figure 3-13 Unit 3 ID Fan Outlet Duct Layout

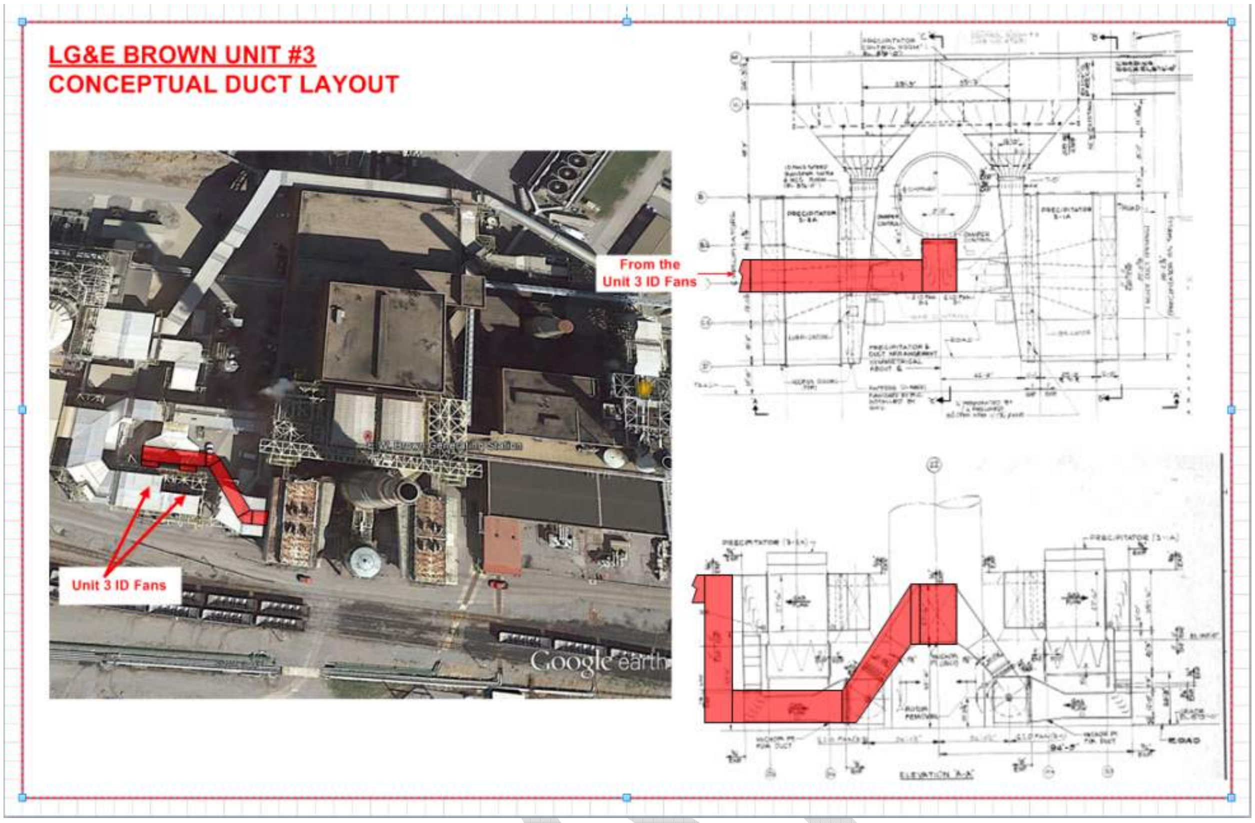



**Figure 3-14 Unit 3 Flue Gas Duct to Unit 3 Original Stack**

## 3.6.1 Induced Draft Fan Analysis

### 3.6.1.1 Unit 1 Induced Draft Fan Analysis

The existing flue gas draft fan system on Unit 1 consists of one ID fan. Its TECO-Westinghouse electric motor has a maximum operating nominal speed of 900 rpm. The nameplate horsepower rating of the ID fan motor is 5,000 horsepower with a service factor of 1.15. It operates at a nominal voltage of 12,400 volts. Primary flow control of the ID fan is accomplished by the use of inlet vanes. The ID fan is a double inlet centrifugal fan with a maximum nominal speed capability of 900 rpm. The ID fan is a TLT-Babcock design, Model 2118AZ/1819.

The Unit 1 fan analysis in Table 3-8 summarizes the expected fan operating conditions firing natural gas. The fan pressure rise requirement is based on the proposed duct layout whereby flue gas from Unit 1 will be routed to the Unit 2 bypass duct and common Unit 3 original stack. Figure 3-15 shows the expected ID fan operating point when burning natural gas with respect to the fan design performance curve.

Although Unit 2 bypass duct would need to accommodate 70% increase in gas flow, the pressure drop through the duct is comparable to the existing pressure drop through the FGD. The flue gas pressure drop from ID fan discharge to the stack is expected to be about 7 to 8 in H2O. Black & Veatch concluded that no modification to the Unit 1 ID fan is required for the natural gas conversion.

**Table 3-8 Unit 1 Induced Draft Fan Analysis**

| UNIT 1 ID FAN PERFORMANCE (PER FAN) | NATURAL GAS |
|---|---|
| Calculated Fan Flow, acfm | 445,857 |
| Fan Static Pressure Rise, in $H_2O$ | 22.0 |
| Flue Gas Temperature, F | 292 |
| Flue Gas Density, lbm/ft$^3$ | 0.048 |
| Fan Design Temp, F | 410 |
| Fan Design Density, lbm/ft$^3$ | 0.040 |
| Corrected Fan Flow, cfm @Design Density | 528,847 |

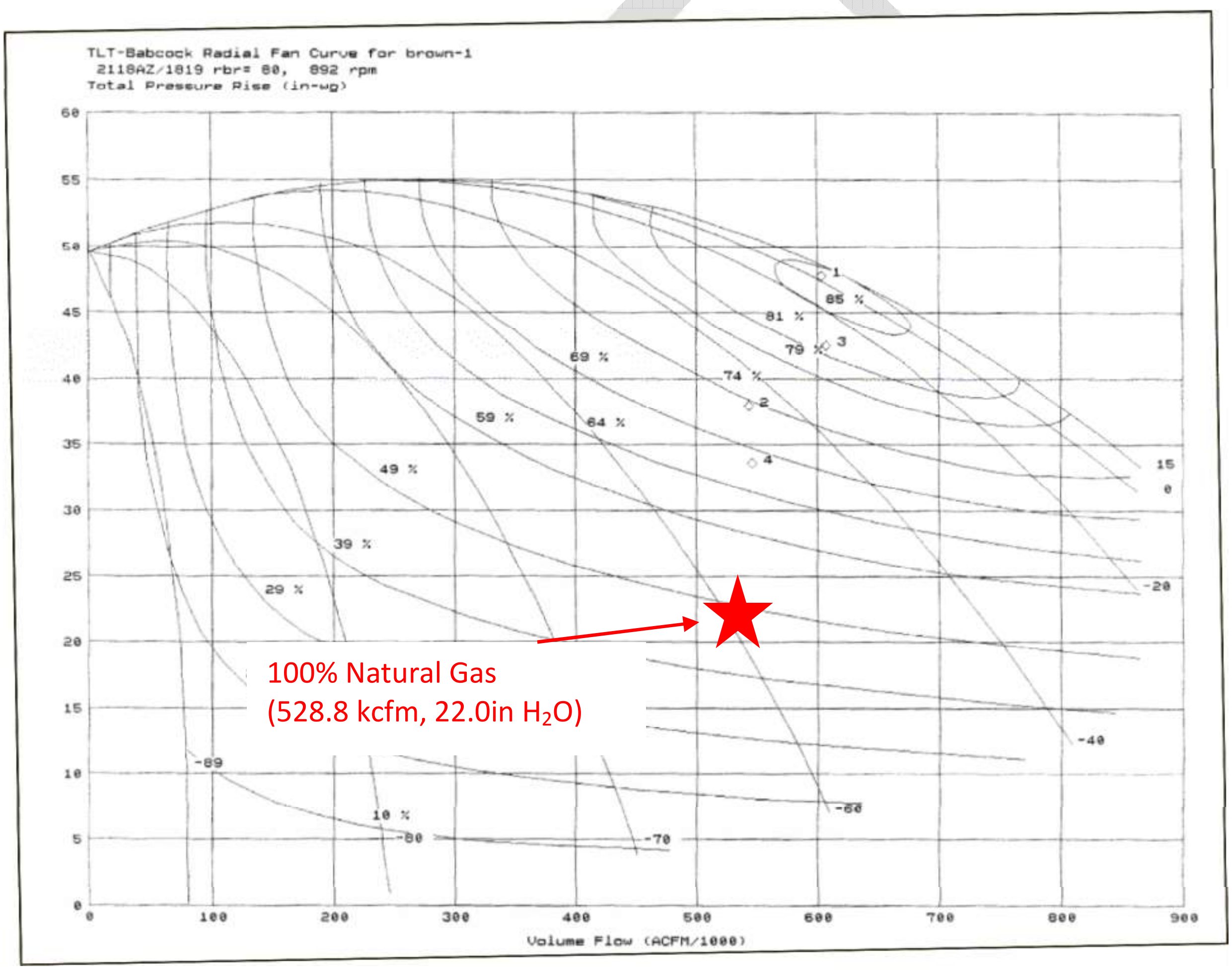



**Figure 3-15 Unit 1 ID Fan Expected Performance with Natural Gas**

#### 3.6.1.2 Unit 2 Induced Draft Fan Analysis

The existing flue gas draft fan system on Unit 2 consists of two ID fans. The TECO-Westinghouse two-speed pole amplitude modulation (PAM) electric motors are designed to operate nominally at 590 rpm at low speed and 890 rpm at high speed. The nameplate horsepower ratings of the motors are 800 at low speed and 2,500 at high-speed with a service factor of 1.15. They operate at a nominal voltage of 2,400 volts. Primary flow control of the ID fans is accomplished by the use of inlet vanes. The ID fans are a TLT-Babcock double inlet centrifugal design, Model 1904AZ/1633/0.

The ID fan analysis in Table 3-9 summarizes the expected fan operating conditions firing natural gas. The fan pressure rise requirement is based on the proposed duct layout whereby flue gas from Unit 2 will be routed to the Unit 2 bypass duct and to common Unit 3 original stack. Figure 3-16 shows the ID fan operating point when burning natural gas with respect to the fan design performance curve at high speed.

Although Unit 2 bypass duct would need to accommodate 70% increase in gas flow, the pressure drop through the duct is comparable to the existing pressure drop through the FGD. The flue gas pressure drop from ID fan discharge to the stack is expected to be about 7 to 8 in $H_2O$. Black & Veatch concluded that no modifications to the Unit 2 ID fans are required for the natural gas conversion.

**Table 3-9 Unit 2 Induced Draft Fan Analysis**

| UNIT 2 ID FAN PERFORMANCE (PER FAN) | NATURAL GAS |
|---|---|
| Calculated Fan Flow, acfm | 309,671 |
| Fan Static Pressure Rise, in $H_2O$ | 20.2 |
| Flue Gas Temperature, F | 323 |
| Flue Gas Density, lbm/ft$^3$ | 0.046 |
| Fan Design Temp, F | 300 |
| Fan Design Density, lbm/ft$^3$ | 0.049 |
| Corrected Fan Flow, cfm @Design Density | 291,154 |

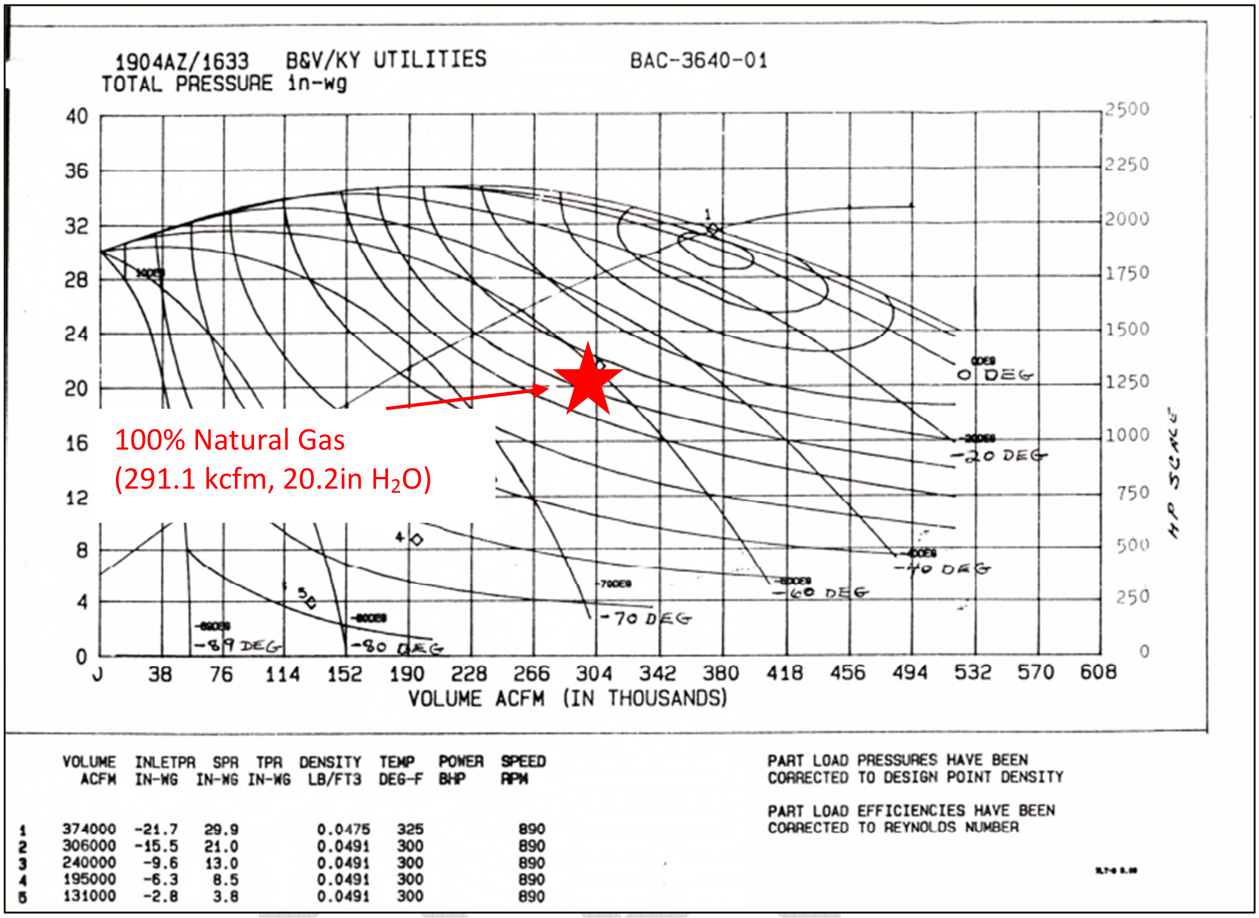



**Figure 3-16 Unit 2 ID Fan Expected Performance with Natural Gas**

### 3.6.1.3 Unit 3 Induced Draft Fan Analysis

The existing flue gas draft fan system on Unit 3 consists of two ID fans. The TECO-Westinghouse two-speed electric motors are designed to operate nominally at 714 rpm at low speed and 891 rpm at high speed. The nameplate horsepower ratings of the motors are 6300 at low speed and 10,750 at high-speed with a service factor of 1.15. They operate at a nominal voltage of 12470 volts. Primary flow control of the ID fans is accomplished by the use of inlet vanes. The ID fans are a TLT-Babcock double inlet centrifugal design, Model 1904AZ/2327.

The ID fan analysis in Table 3-10 summarizes the expected fan operating conditions firing natural gas. The fan pressure rise requirement is based on the proposed duct layout whereby flue gas from Unit 3 will be routed to common Unit 3 original stack via the new proposed duct layout shown in Figure 3-14. Figure 3-17 shows the ID fan operating point when burning natural gas with respect to the fan design performance curve.

The new duct layout from Unit 3 ID fan discharges to Unit 3 original stack would reduce the fan pressure rise requirement considerably due to shorter duct run and also avoiding the high pressure drop across the FGD. The expected gas pressure drop through the new duct route (from ID fan discharge to Unit 3 original stack) is about 6 in $H_2O$. Black & Veatch concluded that no modifications to the Unit 3 ID fans are required for the natural gas conversion.

**Table 3-10 Unit 3 Induced Draft Fan Analysis**

| UNIT 3 ID FAN PERFORMANCE (PER FAN) | NATURAL GAS |
|---|---|
| Calculated Fan Flow, acfm | 853,740 |
| Fan Static Pressure Rise, in $H_2O$ | 34.1 |
| Flue Gas Temperature, F | 292.4 |
| Flue Gas Density, lbm/ft$^3$ | 0.0479 |
| Fan Design Temp, F | 330 |
| Fan Design Density, lbm/ft$^3$ | 0.0482 |
| Corrected Fan Flow, cfm @Design Density | 848,779 |

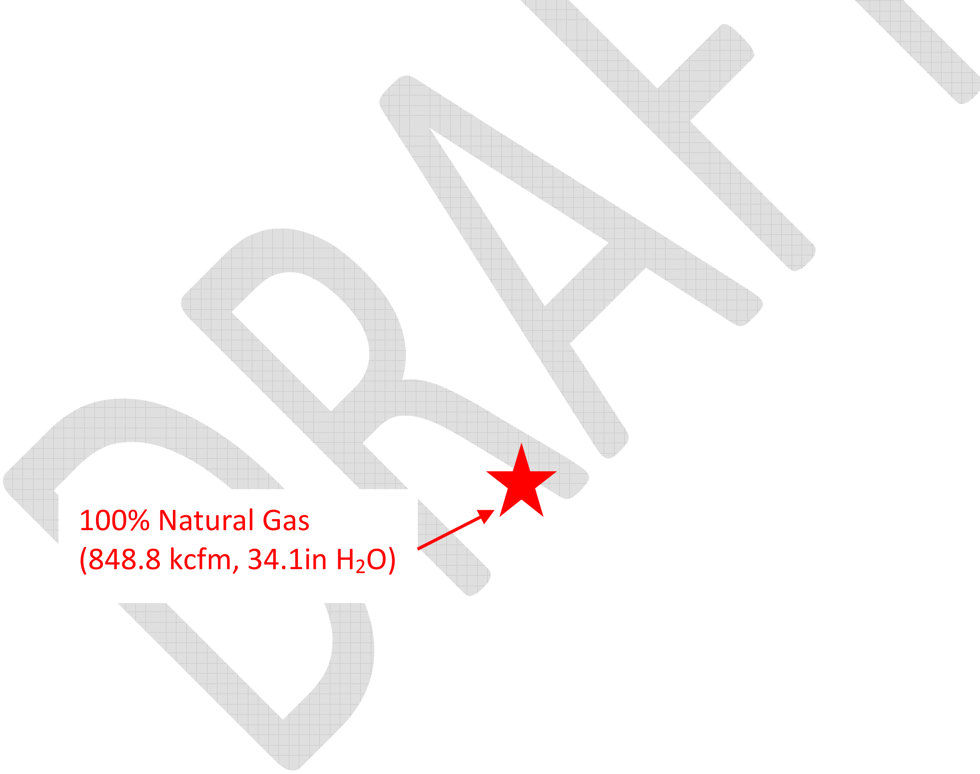



**Figure 3-17 Unit 3 ID Fan Expected Performance with Natural Gas**

# 3.7 CONTROL SYSTEM MODIFICATIONS

## 3.7.1 Distributed Control System and Burner Management System Modifications

Existing BMS and BCS I/O and control processors will be repurposed and reconnected to new equipment. New control logic and DCS reprogramming will be required to support the replacement of the coal burners with natural gas burners on Units 1 and 2. The existing Unit 1 and Unit 2 DCS system and HMI will support the re-used and re-purposed BCS and BMS I/O required for the new equipment. The Unit 3 DCS processors and HMI will support the BCS for the replacement gas burner equipment. The Allen Bradley BMS system for Unit 3 will be replaced with a new BMS. The allowance for one cabinet will allow a replacement to the PLC or inclusion in the DCS. Replacement of the existing MFT scheme will be required for conversion to the natural gas burners and associated equipment. To facilitate factory testing, new MFT relays and associated hardwiring should be factory installed in a new MFT cabinet for each Unit.

## 3.7.2 Instrumentation

Instrumentation has been incorporated to control the new natural gas supply and burner equipment. Flow transmitters have been included on the natural gas supply to each unit to support boiler fuel input calculations. It should be noted that the selection of flow instrumentation should be optimized during detailed design to consider straight run and unrecoverable pressure losses and their associated costs. Pressure instrumentation has been incorporated both for control and to provide the necessary interlocks in accordance with NFPA 85. Burner supply pressure interlocks for the BMS will be developed from set points off of the pressure transmitters used for control in the BMS and transmitted via hard-wired I/O between the BMS and BMC in accordance with NFPA 85. Alternatively, pressure switches (in addition to the control transmitters included in the conceptual design) can be incorporated into the detailed design to provide independent hard-wired interlocks to the BMS.

# 3.8 AUXILIARY ELECTRICAL SYSTEM IMPACTS

No major additions to the existing auxiliary electrical system are needed. Burner block and vent valves will be air operated valves. Present ID and FD fans are to remain so that no new major power requirements are foreseen.

## 3.8.1 Draft System Impacts

The net result of the natural gas conversion should be an overall reduction in fan horsepower from baseline levels. In addition, the removal of the pulverizers and primary air system from service will create further reductions in unit auxiliary power.

### 3.8.2 Other Electrical System Impacts

New natural gas pressure reducing stations will require power for control panels. Each reducing station power supply will be fed by existing plant equipment and will have negligible electrical power consumption. Electrical routing to the gas reducing stations, gas heaters and unit gas flow meter stations is included in the cost estimate.

During the unit walk down, pieces of equipment impacted by the gas conversion were noted. Equipment within a 15 foot radius of the burner front or new gas conversion equipment leakage points must meet NEC rating for a hazardous environment. They will be required to be moved or replaced with equipment rated for a Class 1 Division 2 environment (explosion proof or intrinsically safe or placed in z-purge panels) per Black & Veatch standard. This could include such items as lights, lighting panels, MCC, cabinets, and motors which would fall within these areas.

Additionally, a number of junction boxes fall within the 15 foot radius of the burner front or new gas equipment. Many are associated with the coal system and will be abandoned in place or demolished as part of the upgrade as determined during detailed design. While junction boxes with terminations are not required to be purged, intrinsically safe or explosion proof, junction boxes that remain in service will require conduit seal-offs to be added. This requires the terminal blocks within the cabinet to be de-terminated and re-terminated. These costs have been included in the project cost estimate.

## 3.9 NFPA IMPACTS

### 3.9.1 Hazardous Classification Impacts

NFPA 497 defines hazardous area classifications involving flammable or combustible liquids, combustible gases, or combustible dusts. This classification is necessary for the proper selection and installation of electrical equipment. The National Electric Code (NEC), as defined by NFPA 70, defines the requirements for electrical equipment and associated installation methods within the boundaries of hazardous areas defined by NFPA 497. In many cases, this requires vendors to provide equipment in explosion proof enclosures, the installation of purge air systems, or the use of intrinsically safe barrier systems. Electrical installation methods include the use of raceway systems specifically rated for the hazardous area and the use of seal-offs in raceway that crosses the hazardous area boundary.

Assuming that the existing powerhouse meets the definition of being well-ventilated, NFPA 497 requires that 15 foot spheres around each potential leakage point be classified as a Class I Division II hazardous area. Long sections of welded natural gas piping without any flanges, valves, or instruments will not require a hazardous area classification. The 50 psig fuel gas piping to the burners includes flanged connections, stem packing on the control and shutoff valves, and fittings on instrument connections that represent potential leakage points. As a result, all existing electrical components and raceway within the 15 foot sphere of potential leak points not rated for a Class I Division II environment will require replacement with appropriately rated equipment and materials. An allowance has been assigned to lighting, receptacles, communications equipment, power distribution equipment, control panels, drives, associated raceway, and other equipment that were identified for replacement in classified areas. Costs to upgrade the coal supply equipment were not included at this time; it has been assumed that the coal supply equipment will be taken out of service during the conversion to 100 percent natural gas firing and therefore does not require upgrades.

Many clients are concerned about the impacts to maintenance and cost associated with classification of a burner front. In some cases, clients consult with their insurance carrier and/or steam generator supplier regarding these risks and choose to not classify the burner front area. Black & Veatch's standards require that its detailed designs adhere to the NFPA 497 and NEC requirements for hazardous area classification. However, with the appropriate documentation and direction from the client, a client's design criteria can be utilized if desired.

### 3.9.2 NFPA 85 Implosion Control

Although no FD or ID fan modifications are anticipated at this time to enable natural gas firing on any of the units, there will be increased implosion potential in each boiler due to the firing characteristics of natural gas compared with coal. Natural gas can "flame out" much more quickly than coal, and natural gas does not have residual heat remaining in pulverized fuel pipes like coal. The result is the potential for an immediate drop in boiler temperature, rapidly lowering the internal boiler pressure. To fully evaluate the impacts and required boiler pressure rating due to this operating scenario, a Furnace and Draft System Transient Pressure Analysis study is required. To some extent, the boiler depressurization can be mitigated with controls optimization (damper and fan operation control); this will also need to be evaluated by this model.

### 3.9.3 Conceptual Control Philosophy

This subsection provides a high-level overview of the conceptual operating and control philosophy which could be employed during start-up, normal operation, shutdown, and transient operation.

#### 3.9.3.1 Startup

##### 3.9.3.1.1 Open Flow Air Path Requirement

Article 6.5.3.2 of NFPA 85 requires that an open flow path be ensured under all operating conditions, including the required condition before and during starting draft fans. Article 6.5.3.2.4 states "Provisions of the open path shall be ensured while starting the first induced draft fan and forced draft fan." For multiple ID or FD fan applications, Article 6.5.3.2.4.1(2) states "…all flow control devices and shutoff dampers on idle fans shall remain open until the first induced draft fan and the first forced draft fans are in operation while maintaining furnace pressure conditions and indication of an open-flow path." The Annex reference for this paragraph then allows closing the opposite ID fans dampers prior to starting the first FD fan if a crossover exists. Standard Black & Veatch practice is to ensure the flow path by physical measurement means, such as damper limit switches and the like before starting fans and establishing purge airflow. After air flow is established and firing commences, the open flow path is proved inferentially, by the following means:

- Air flow through the furnace and ductwork must be maintained at or above the required purge rate.
- Furnace pressure must be maintained within specified limits.

These conditions do not require monitoring of limit switches, and consequently enhance unit availability.

#### 3.9.3.1.2 Starting of the First Unit

To accommodate NFPA open-flow air path requirements, an open flow path must be provided from the inlet of the FD fan through the stack during starting of the first set of fans. The order of starting fans will be:

- First ID Fan
- First FD Fan
- Damper setup for starting the first boiler as required by NFPA paragraph 6.5.3.2 to be open for startup shall be opened to complete the air flow path.
- The fan isolation damper(s) for the boiler not being started shall be closed to force the purge air flow to travel through the boiler and setting being purged. This will prevent any tendency for the ID fan motors to be overloaded during the air purge of the first boiler.
- As part of the starting logic for the first ID Fan to be started, ID fan inlet dampers on the first ID fan to be started shall be closed. The running ID Fan will be limited to the minimum fan operating speed while the isolation dampers are not in the full open position to ensure the ductwork design pressure is not exceeded.
- Fan inlet damper on the opposite ID fan shall remain open to maintain an open-flow path.

With the existing unit related dampers open in the stated positions, a complete open-flow air path is established.

- The first unit's ID fan can now be started followed by start of the first unit's FD fan, in accordance with NFPA 85 open-flow air path requirements.
- The ID fan should be transferred to Auto mode to maintain furnace pressure.
- The FD fan control will be used to bring boiler air flow to furnace purge air flow.
- After furnace purge is complete, igniter operation, boiler warm-up, turbine synchronization and unit loading can progress. The remaining ID fan and FD fan on the unit can be started and placed in service, as required, in accordance with normal procedures.

#### 3.9.3.1.3 Startup of Unit with a Unit Already In-Service

With a unit already in service, an open-flow path is inferentially assured through the stack for the running unit. When starting additional unit, an open flow path through the draft system should be maintained during the startup process. The ID and FD fan start-up may then proceed in accordance with NFPA requirements. Furnace purge, igniter operation, boiler warm-up, turbine synchronization and unit loading can proceed normally.

#### 3.9.3.2 Normal Operation

The furnace pressure and draft fan controls should require little to no operator attention during normal operation. Each unit's FD and ID fan will be under automatic control by the DCS. During load changes, ID fan inlet vane position will be adjusted by the DCS to maintain furnace pressure in each unit.

#### 3.9.3.3 Controlled Shutdown of an ID Fan

The fan demand control for the ID Fan being stopped should be transferred to manual control, and slowly decreased by the operator. The DCS will react by increasing the demand to the other ID Fan. If the operator determined that the unit load could be carried by a single ID Fan, the fan demand to the fan being stopped could be reduced to zero. When the demand to the fan was zero, the fan motor could be stopped. The inlet dampers for the non-running fan will be automatically closed to isolate the fan, pending a requirement for restart.

#### 3.9.3.4 Transient Operation

Transient or upset operation can be categorized as a transient event generated from the boiler or a transient event from auxiliary equipment such as FD fans, induced draught (ID) fans, pulverizers, or air compressors (loss of control air), turbine trip to house load, or a rapid boiler load reduction to bypass operating mode. Depending on the type of event, operating conditions may require that the operator or the control system to take corrective action.

Some events may require the initiation of a master fuel trip (MFT) to rapidly shutoff all fuel to all burners, including igniters to protect equipment and personnel. The events which will cause a MFT include the following.

- Loss of flame
- Loss of both FD fans
- Loss of both ID fans
- Loss of both PA fans
- Loss of all fuel
- Low combustion airflow
- High negative or positive furnace pressure
- Boiler management system failure
- DCS communication failure
- Manual trip switch

The following subsections summarize the prescribed action in NFPA 85.

#### 3.9.3.5 Master Fuel Trip (MFT)

Following an MFT event where the FD and ID fans remain in service, an immediate post combustion purge should be performed to remove any unburned fuel or combustibles from the furnace. If the airflow falls below the purge rate, the airflow should be maintained at this rate for 5 minutes then increased gradually to the purge rate. This purging condition will need to be maintained for at least 5 minutes before either shutting the fans downs or reintroducing fuel into the furnace.

#### 3.9.3.6 MFT with Loss of All Fans with Other Units in Operation

Following a master fuel trip (MFT) event where no fans remain in service on one of the units, no action shall be taken while the fans coast down unless it is necessary to reposition dampers to prevent a positive or negative pressure excursion from exceeding the furnace's structural design capability. When fans have stopped, the tripped unit can be isolated from the operating units in accordance with item 4 under 6.4.1.2.4.3C of NFPA 85 to prevent a backflow of flue gas into the idle unit. NFPA does not prescribe the actions which should be taken following the isolation of the gas path but there are essentially two options which could be considered.

The first option would be to allow for the unit to cool down reducing the likelihood of igniting combustible gases that could be present within the unit trip. The second option would be to establish a natural draft through one of the existing unit stacks which is no longer utilized for normal operation. This is the preferred option as it would reduce the potential for the accumulation of combustible gases. An allowance of $1.5 million is recommended to redirect the Unit 1 and Unit 2 flue gas flow to the existing Unit 1 exhaust stack. This recommended allowance has not been included in the estimate provided.

Unit 3 presents some additional challenges which will require further review to determine the best possible option to forward with. Options which could be considered would include the following:

- Installation of a natural draft breather vent (supported off of the existing Unit 3 boiler structure). The projected cost for this arrangement is $400,000 to $800,000 depending on the tie-in point.
- Permitting the flue gas temperature in the unit to cool to a temperature where the flue gas could be directed to wet flue gas desulfurization stack.

Installation of a natural draft breather vent to the existing wet stack was considered briefly but is not considered viable due to temperature limitations of the liner or the requirement to maintain an emergency quench system in operation after decommissioning of the remainder of the scrubber. Other options may also be available and should be evaluated to determine the best course of action to move forward with.

#### 3.9.3.7 MFT with Loss of All Fans during Single Unit in Operation

If the all fan trip occurs with only a single unit in operation, the dampers in the system will be slowly opened once the FD and ID fans have stopped to establish a natural draft through the unit. This condition should be maintained for at least 15 minutes to remove any unburned fuel or combustibles from the furnace. The FD and ID fans should then be restarted and the airflow gradually increased to the purge rate. This condition will need to be maintained for at least 5 minutes before either shutting the fans down or reintroducing fuel into the furnace.

#### 3.9.3.8 Trip of a Single FD or ID Fan

The tripped fan will be isolated. The unit load will be run back to a point that the remaining unit draught fans could maintain the operating parameters within the established limits.

**Analog Control Action**

It is presumed that the existing unit control systems will react to loss of an individual draft fan by appropriate action, i.e. the remaining fan of the pair will be increased as much as possible, and the unit load will be runback to a point that the remaining unit draft fans could keep the operating parameters such as furnace draft and fuel/air ratio within proper limits. However, this should be verified. There will be no need for specific analog action by the ID Fan controls, except as called for by the feedforward from the unit controls.

**Digital Control Action**

It is presumed that the existing unit control systems will react to loss of an individual unit FD fan by appropriate action, i.e. the tripped fan's isolation dampers will be closed to ensure maximum capability of the remaining fan(s). However this should be verified. There will be no need for specific interlock action by the ID Fan controls, since both ID Fans will still be in range, and be capable of modulating the flue gas flow to keep the set pressure at the desired value.

#### 3.9.3.9 Loss of Both FD Fans

Following the loss of both FD fans, the fuel should be tripped and a post combustion purge performed using the ID fans in accordance with Section 3.9.3.5.

#### 3.9.3.10 Loss of Both ID Fans

Following the loss of both ID fans, the fuel and FD fans should be tripped. The actions described in Section 3.9.3.6 will need to be taken.

#### 3.9.3.11 Hot Trip with Fans Remaining in Service

Article 6.6.5.2.5.4 of NFPA 85 does not permit draft fans to be tripped if they are in service after a fuel trip. Air flow also shall not be purposely increased. Practically speaking, this means the FD fans of the affected unit shall be rejected to manual control, while the ID fans remain in automatic, controlling furnace draft.

- If air flow through the affected unit prior to trip was above purge flow, the flow shall be decreased gradually to purge air flow rate, and shall be maintained for 5 minutes.

- If air flow through the affected unit prior to trip was below purge flow, it shall be maintained at that rate for 5 minutes, and then gradually increased to purge flow. The furnace purge shall be conducted, and the boiler shall be re-started normally, i.e. in accordance with Section 3.9.3.1.

#### 3.9.3.12 Hot Trip with Loss of Both FD or ID Fans

A unit trip caused by loss of both fans (i.e., both ID fans or both FD fans) of an individual unit is addressed in Article 6.4.1.2.6 and 6.4.1.2.7 of NFPA 85. It is presumed that the existing individual unit control system logic already includes provisions to conform to the NFPA requirements, insofar as the individual unit tripping is concerned, but this should be verified. Black & Veatch recommends that the fuel tripping be automatic in these cases. Article 6.6.5.2.5.5 will require the unit to undergo a post trip purge to clear any remaining combustible gases from the furnace and ductwork. Loss of only the FD fans will require only a 5 minute induced draft purge. Loss of both ID will require the actions prescribed in Section 3.9.3.6 to be followed.

#### 3.9.3.13 Loss of a Single Item of Unit Auxiliary Equipment Other than Draft Fans

It is presumed that the existing control systems will react to loss of a single item of auxiliary equipment, i.e. a feedwater pump, by limiting unit load or by running unit load back as appropriate. However, this should be verified. There will be no need to take any specific interlock action in regard to the ID Fan controls, except to respond to the analog feedforward as previously described.

### 3.9.4 Shutdown

During a normal shutdown, the heat input (firing rate) to the unit will be decreased as the steam turbine generator load is decreased. Following the last burner level, a post combustion purge of the furnace will be performed. Once the unit is completely purged, the offline unit would be isolated to prevent entrainment of flue gas from running unit.

## 3.10 EMISSIONS IMPACTS

$NO_x$ emissions are expected to be very different when firing 100 percent natural gas compared to firing coal for two main reasons:

- Natural gas as a fuel burns very differently than coal in the furnace. Natural gas has little to no fuel-bound nitrogen content and does not suffer from char-bound nitrogen, which can result in large amounts of fuel-related $NO_x$ emissions.
- The natural gas combustion process requires a much lower excess air level than the coal combustion process, reducing the potential for $NO_x$ formation.

**$NO_X$ Emissions**

The maximum hourly $NO_x$ emissions will decrease with the addition of new natural gas burners and Separated Overfire Air (SOFA). The expected emissions will range from 0.12 -0.17 lb/MBtu on Unit 1 and 0.10 lb/MBtu for Units 2 and 3. The baseline NOx emission rate is around 0.30 lb/MBtu for Units 1 and 2 based on emissions data from 2016. LG&E KU 2017 targets for $NO_x$

emissions are 0.4 lb/MBTU for Unit 1, 0.5 lb/MBtu for Unit 2 and 0.04 lb/MBtu for Unit 3. The Unit 3 baseline emission rate is not known but the SCR is designed to maintain the $NO_x$ emissions at or below 0.04 lb/MBtu. The boiler flue gas conditions when burning natural gas are very similar to current flue gas conditions.

The existing SCR catalyst should work under the new exhaust conditions assuming the catalyst reactor has potential left. The flue gas flow rate is approximately 9 percent lower when burning natural gas compared to coal operation. Additionally, the flue gas temperature is about 30-35 ˚F lower out of the economizer when burning natural gas. Ammonium Bisulfate formation will not be an issue at these temperatures because of the low sulfur levels.

The SCR catalyst is a solid state acid and for coal applications needs sulfur to work properly because of the reduced vanadium content. This means the activity of the catalyst will be affected by the change to natural gas fuel and lower sulfur levels. The amount of moisture, oxygen and lower temperature will also affect the activity of the SCR catalyst. These factors will negatively affect the SCR System performance but the inlet $NO_x$ is lower than the current design and therefore the catalyst is likely oversized for this application and should be able to control $NO_x$ emissions to the current permit level of 0.07 lb/MBtu on a 30 day rolling average.

It will be important to remove any fly ash from the catalyst, as well as any unburned carbon or large particle ash. Cleaning the catalyst would reduce the potential for fires, increase surface area available for reaction, and lower the pressure drop through the catalyst.

Working with a catalyst supplier the plant could test the catalyst to determine the remaining activity based on the new design conditions. From this data and the required $NO_x$ removal the supplier could model the SCR system and develop a catalyst management plan for the new operating parameters. Replacement catalyst would be formulated with natural gas application activity levels.

CO emissions are not currently monitored on the Brown units. Black & Veatch expects that the LG&E KU Brown Units report CO emissions based on AP-42 factors for bituminous coal. The emissions guarantees provided by the burner suppliers for Natural Gas firing is higher than the coal AP-42 emissions factors. There currently are no AQCS systems installed on the three units to control CO emissions. CO catalyst is available and has been utilized on Combined Cycle Power Plants burning natural gas. Please see the permit review section for additional discussion on CO emissions.

**$CO_2$ Emissions**

Natural gas has a higher heat content than coal so when it produces less $CO_2$. Taking in account the efficiencies of these boilers Vista estimates that the $CO_2$ produced when combusting Natural gas will be about 40 percent less than when burning coal at full load. Table 3-11 and Table 3-12 show the estimated $CO_2$ emissions for both coal and natural gas for all three units at base load. The ton per year values were calculated based on a capacity factor of 30 percent for all three units.

### Table 3-11 Natural Gas Emissions Estimate – $CO_2$ Emissions (lb/h)

| | $CO_2$ EMISSIONS – COAL (LB/HR) | $CO_2$ EMISSIONS – NATURAL GAS (LB/HR) | PERCENT REDUCTION OF $CO_2$ EMISSIONS |
|---|---|---|---|
| Brown Unit 1 | 240,768 | 147,553 | 38.7 |
| Brown Unit 2 | 362,146 | 215,249 | 40.6 |
| Brown Unit 3 | 927,437 | 563,186 | 39.3 |
| Notes:<br>Capacity factor is assumed to be 30 percent for Units 1 and 2. Capacity factor is assumed to be 75 percent for Unit 3. | | | |

### Table 3-12 Natural Gas Emissions Estimate – $CO_2$ Emissions (tons/yr)

| UNIT | $CO_2$ EMISSIONS – COAL (TONS/YR) | $CO_2$ EMISSIONS – NATURAL GAS (TONS/YR) | REDUCED $CO_2$ EMISSIONS (TONS/YR) |
|---|---|---|---|
| Brown Unit 1 | 316,369 | 193,884 | 122,485 |
| Brown Unit 2 | 475,860 | 282,838 | 193,022 |
| Brown Unit 3 | 1,218,652 | 740,026 | 478,626 |
| Notes:<br>Capacity factor is assumed to be 30 percent for all three units. | | | |

### Table 3-13 Natural Gas Emissions Estimate - Uncontrolled

| | UNIT 1 | UNIT 2 | UNIT 3 |
|---|---|---|---|
| $CO_2$, lb/h from fuel | 147,500 | 215,250 | 563,200 |
| $NO_x$ , lb/MBtu* | 0.12 – 0.25 | 0.10 -0.12 | 0.08 – 0.12 |
| CO, lb/MBtu | 0.15 | 0.15 | 0.15 |
| $SO_2$, lb/h | Negligible | Negligible | Negligible |
| $SO_2$, lb/MBtu | Negligible | Negligible | Negligible |
| $H_2SO_4$ | Negligible | Negligible | Negligible |
| PM | Negligible | Negligible | Negligible |
| Mercury | Negligible | Negligible | Negligible |

**Stack Considerations**

The plant currently plans to utilize the abandoned Unit 3 dry stack when the units are converted to natural gas firing. Based on the stack diameter (18'-6") the stack velocity when only Unit 3 is operating at base load will be approximately 80 ft per second. The velocity will increase to approximately 122 feet per second when all three units are operating at base load.

The expected pressure at the stack inlet would be 1.7 in $H_2O$ for the Unit 1 &2 duct and 4.3 in $H_20$ for the Unit 3 duct. The flue gas flow rate has been assumed to be constant based on maintaining a constant outlet temperature at the outlet of the air heater. The pressure drop for the stack entrance, stack friction and stack discharge loss is 4.7 in H2O for Unit 1 & 2 and 3.6 in H20 for Unit 3. The stack entrance loss makes up the difference in the pressure drops. The stack draft loss varies with the ambient temperature. Figure 3-18 shows the stack effect versus ambient temperature.

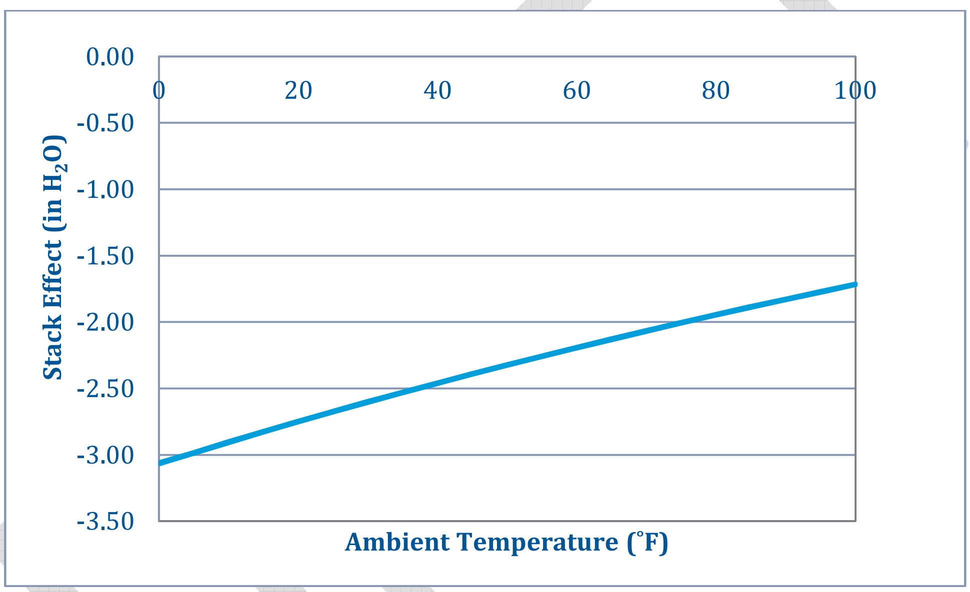



**Figure 3-18 Stack Effect**

The condition of the abandoned Unit 3 stack was not assessed for this study. It is assumed the stack is in good condition. The plant may want to complete an inspection of the abandoned Unit 3 stack prior to proceeding with these plans.

The abandoned Unit 3 stack has a carbon steel liner. There should be no problems with the liner with the higher velocities predicted when all three units are operating at base load.

**CEMS System**

The existing CEMS System is located on the combined Unit 1, 2 and 3 stack and monitors $NO_x$, $CO_2$, $SO_2$, PM, flow, Opacity, and Mercury. Additionally, there is an $SO_2$ and $CO_2$ monitor at the Unit 3 FGD Inlet and a $NO_x$, $CO_2$ and flow monitor on the Unit 3 Ductwork. These monitors were required due to the SCR and WFGD systems.

PM and mercury monitors were installed to monitor emissions for the MATS rule. The MATS rule will no longer apply to these units once they have been converted to natural gas. The $SO_2$ monitors (both at the stack and at the WFGD inlet) will no longer be necessary as $SO_2$ should not need to be monitored. The opacity monitors are not required because units burning natural gas fuel are exempt from the opacity standard in 40 CFR 60 Subpart Da. Natural gas plants mostly use the fuel flow meters to calculate the heat input to the units. The fuel flow meters are more accurate than the stack flow monitor resulting in greater accuracy in emissions reporting. The fuel flow meters also will not require yearly RATAs. Black & Veatch recommends using the fuel flow meters to monitor heat input.

The abandoned Unit 3 dry stack is to be reused for all three Units once they are converted to natural gas firing. This unit has an existing CEMS that has not been operated or maintained for approximately 1 year. The system includes $NO_x$, $CO_2$, $SO_2$, flow and opacity monitors. As previously discussed the $SO_2$, flow and opacity monitors will not be needed. This CEMS system is a dilution extractive system. It is likely the emissions will need to be reported on a dry basis at a reference $O_2$ level.

Many components of the existing system can be reused. The CEMS Shelter, analyzer racks, calibration bottle valve train, sample conditioning station, UPS, and transformer can be reused.

There are two options for the CEMS on this unit. The first is to retain the $NO_x$ analyzers, probe and umbilical and the components listed above. New CO, in situ $O_2$ and moisture analyzers would need to be added. The Data Acquisition and Handling System (DAHS) system would need to be updated with new software and the data logger would likely need to be replaced. The spans and ranges on the $NO_x$ analyzer would need to be updated and new calibration gases would be required. The CEMS monitoring plan would need to be updated and the entire system would need to be certified. Depending on condition, it is possible the umbilical would need to be replaced as well.

The second option would be to purchase a new extractive CEMS system. The CEMS shelter, analyzer racks, calibration bottle valve train, sample conditioning station, UPS and transformer would be reused in this system. New $NO_x$, CO, and $O_2$ analyzers would be required, as would a new probe and umbilical. Similar to the other option the DAHS would need to be updated and a new data logger would likely be required. The CEMS monitoring plan would need to be updated and the entire system would need to be certified. There are several advantages to this system. A moisture analyzer is not required and the $O_2$ analyzer would be located in the CEMS shelter rather than at the stack. It is assumed that there is sufficient I/O available to accommodate the new CEMS system. It is Black & Veatch opinion that procuring a new extractive CEMS system would decrease the risk of integration issues and provide a lower life cycle cost for the plant. Costs for the replacement extractive CEMS system have been included in the estimate for the natural gas conversion.

# 4.0 Environmental Permitting and Regulatory Considerations

## 4.1 NEW SOURCE REVIEW

The federal Clean Air Act (CAA) New Source Review (NSR) provisions are implemented for new major stationary sources and major modifications at existing major sources under two programs: the Prevention of Significant Deterioration (PSD) program outlined in 40 CFR §52.21 for areas in attainment of the National Ambient Air Quality Standards (NAAQS), and the Non-Attainment NSR (NA-NSR) program outlined in 40 CFR §51 and §52 for areas classified as not in attainment of the NAAQS (i.e., non-attainment areas). Currently, Mercer County, Kentucky, in which E.W. Brown operates, is designated as either attainment or unclassifiable for all criteria pollutants. As such, a determination of whether or not the proposed project would qualify as a major modification at an existing major source would need to be made in accordance with the procedures outlined in the PSD program in order to determine if the requirements of PSD apply to the proposed project. Obtaining a PSD permit involves several rigorous requirements including the application of Best Available Control Technology (BACT) and the performance of an air dispersion modeling analysis in order to closely examine the effects of the project's emissions on the ambient air quality.

In order for the project to be deemed a major modification under the definition provided in 40 CFR §52.21, it must be determined that the project results in both a significant emissions increase and a significant *net* emissions increase. The process of determining whether a significant emissions increase will result from the construction of a project is commonly referred to as "Step1" of the PSD applicability test. Because E.W. Brown is an existing major source under the PSD program, the Step 1 evaluation will be conducted on a pollutant by pollutant basis by comparing the emissions increase of each pollutant against the PSD significant emissions rates (SERs). If a project's emissions increases of a given pollutant are larger than the SER, then the project is considered to result in a significant emissions increase. Since the project will involve existing emissions units, this Step 1 emissions increase, or projected emissions increase (PEI), can be calculated as the difference between either the projected actual emissions (PAE), or the potential to emit (PTE), and the baseline actual emissions (BAE)[1,2]. Because the project entails converting coal-fired units to burn natural gas, the PAE cannot easily be determined. Therefore, the PTE[3] would likely be used in conjunction with the BAE to determine the PEI of the project in Step 1 of the PSD applicability determination.

[1] According to 40 CFR §52.21BAE is defined as the average rate, in tons per year (tpy), at which the emissions unit actually emitted a regulated NSR pollutant during any consecutive 24 month period selected by the owner or operator within the 5-year period immediately preceding when the owner or operator begins actual construction of the project.

[2] Excluding those emission increases resulting from future business activity that the facility could otherwise accommodate.

[3] According to 40 CFR §52.21, PTE is defined as the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. […]

The PSD SERs are listed in Table 4-1 below.

**Table 4-1 PSD Significant Emission Rates**

| POLLUTANT | PSD SER (TPY) |
|---|---|
| Carbon Monoxide (CO) | 100 |
| Nitrogen Oxides ($NO_X$) | 40 |
| Particulate Matter <10 Microns ($PM_{10}$) | 15 |
| Particulate Matter <2.5 Microns ($PM_{2.5}$)[1] | 10 |
| Sulfur Dioxide ($SO_2$) | 40 |
| Volatile Organic Compounds (VOC)[2] | 40 |
| Green House Gases (GHG)[3,4] | 75,000 |

1. For $PM_{2.5}$, the PSD SER is either 10 tpy of direct $PM_{2.5}$ emissions, 40 tpy of $SO_2$ emissions, or 40 tpy of $NO_X$ emissions unless demonstrated not to be a $PM_{2.5}$ precursor under the definition of "regulated NSR pollutant".
2. For ozone ($O_3$), the PSD SER is either 40 tpy of VOC emissions or 40 tpy of $NO_X$ emissions.
3. GHG PSD SER applies to GHG emission on a $CO_2e$ basis, which is the aggregate of emissions of $CO_2$, $CH_4$, $N_2O$, HFCs, and $SF_6$.
4. As a result of a June 23, 2014 Supreme Court Decision, greenhouse gases may not be treated as an air pollutant for purposes of determining whether a source is a major source required to obtain a PSD permit. However, PSD permits that are otherwise required (based on emissions of other pollutants) may continue to require limitations on GHGs based on the application of BACT.

Assuming all other factors are being held equal, due to the cleaner nature of natural gas combustion as compared to coal, conversion of the E.W. Brown coal-fired boilers to natural gas fueled units should result in emissions reductions when comparing the PTE to the BAE for those pollutants that are directly related to fuel content (i.e. particulate matter and sulfur dioxide). Assuming this to be the case, the Step 1 evaluation would show that the project would not result in a significant emissions increase for these pollutants and would thus would be deemed a minor modification not subject to the requirements of PSD permitting. As such, the emissions were not determined for these pollutants.

For pollutants where emissions are associated with the combustion process, the comparison of PTE to BAE is provided in Table 4-2. The PTE was based on vendor data and/or the EPA database of emission factors and was calculated assuming each of the boilers will operate continuously on an annual basis (i.e. 8,760 hours per year). The BAE was based on data provided in the EPA Clean Air Markets Database as well as EPA emission factors. While the calculations performed followed the methodology outlined in the PSD rules, these emissions estimates were based on high-level information and therefore should not be used for any formal permitting activity.

Based on the high level analysis, it would appear the PEI of CO, $NO_X$, and VOC are above the PSD SER. Further investigation may result in the emissions increase to be below the PSD SER by taking restrictions on the capacity factor associated with each unit; however, this investigation is beyond the scope of this work.

**Table 4-2 Projected Emissions Increase Summary**

| POLLUTANT | BOILER 1 (TPY) | BOILER 2 (TPY) | BOILER 3 (TPY) | PROJECT TOTAL (TPY) |
|---|---|---|---|---|
| Baseline Actual Emissions (BAE) | | | | |
| Carbon Monoxide (CO) [1] | 70.9 | 146.6 | 275.9 | 493.4 |
| Nitrogen Oxides ($NO_X$) [2] | 700.9 | 1,472.8 | 2,229.6 | 4,403.3 |
| Volatile Organic Compounds (VOC) [3] | 8.5 | 17.6 | 33.1 | 59.2 |
| Potential to Emit (PTE) [4] | | | | |
| Carbon Monoxide (CO) | 829.1 | 1,210.9 | 3,167.4 | 5,207.4 |
| Nitrogen Oxides ($NO_X$) | 939.7 | 807.2 | 2,111.6 | 3,858.5 |
| Volatile Organic Compounds (VOC) | 29.8 | 43.5 | 113.9 | 187.2 |
| Projected Emissions Increase (PEI) | | | | |
| Carbon Monoxide (CO) | 758.2 | 1,064.3 | 2,891.5 | **4,714.0** |
| Nitrogen Oxides ($NO_X$) | 238.8 | 0.0 | 0.0 | **238. 8** |
| Volatile Organic Compounds (VOC) | 21.3 | 25.9 | 80.8 | **128.0** |

1. **Baseline emissions were based on an emission factor of 0.5 lb-CO per ton of coal burned (USEPA AP-42) and heat input obtained from the US EPA Clean Air Markets database.**
2. **Baseline emissions were based on data obtained from the US EPA Clean Air Markets database.**
3. **Baseline emissions were based on an emission factor of 0.06 lb-VOC per ton of coal burned (USEPA AP-42) and heat input obtained from the US EPA Clean Air Markets database.**
4. **Based on potential heat inputs obtained from the VISTAS model. Unit 1 – 1,262 MBtu/hr; Unit 2 – 1,843 MBtu/hr; Unit 3 – 4,821 MBtu/hr**

Because the Step 1 evaluation shows a significant emissions increase for one or more pollutants, the PSD applicability analysis would move on to “Step 2”, which determines whether a project results in a significant *net* emissions increase. This is accomplished through a source-wide emissions “netting” analysis in which the significant emissions increases resulting from the project (i.e., Step 1 increases) are combined with emissions decreases and/or increases resulting from facility modifications occurring within a “contemporaneous period”. The net emissions are then compared to the applicable SER to determine if the project represents a major modification.

The "contemporaneous period", by definition, begins five years prior to the expected commencement of construction and ends once the modified unit returns to operation. Therefore, any emissions decreases and/or increases resulting from modifications occurring within the five years prior to the beginning of construction of the project through the date that the converted boilers begin operation are required to be included in the Step 2 analysis. Once contemporaneous projects, which could include modifications to facility-wide emissions sources, are identified, historical emissions associated with each modification within a "look back" period are analyzed in order to determine the creditable emissions decreases and/or increases to be included in the Step 2 analysis. The look back period for utilities is five years. A Step 2 analysis was not performed for this study as information regarding source-wide modifications that could be deemed contemporaneous increases/decreases was not available.

Should the gas conversion project be subject to major modification PSD review, as discussed above, BACT would apply and may result in the requirement to install oxidation catalyst for control of CO and VOC emissions for all three units and for Units 1 and 2 the installation of SCR for control of $NO_X$ emissions. The BACT analysis requires the development of a cost analysis for candidate technologies. This cost analysis would need to be completed to determine if such control technologies would be required for the project. The PSD review process could add significant time in the project schedule to account for application preparation as well as agency review and thus should be determined early in the project in order to account for this potential schedule delay.

## 4.2 NEW SOURCE PERFORMANCE STANDARDS (NSPS) APPLICABILITY

### 4.2.1 Existing Boilers

Section 111 of the CAA authorized the USEPA to develop technology based standards which apply to specific categories of stationary sources. These standards are referred to as New Source Performance Standards (NSPS) and are found in 40 CFR §60.

The E.W. Brown Units 1, 2, and 3 are currently "grand-fathered" units and are not subject to any NSPS. However, 40 CFR §60, Subpart A defines a modification as any physical or operational change to an existing unit which results in an increase in the emission rate (on a kg/hr basis) of any pollutant to which a standard applies. The proposed conversion to natural gas will likely result in a decrease of emissions on a kg/h basis for those pollutants for which a standard applies and therefore will not constitute a modification under the NSPS definition. As such, the proposed project will not affect the applicability of Units 1 and 2 to 40 CFR §60, Subpart Da.

Regarding Unit 3, an SCR is currently employed to control $NO_X$ emissions. If the SCR would remain in use following the conversion to natural gas, a potential strategy to avoid applicability to NSPS Subpart Da as a modified unit could be to control $NO_X$ to such a degree that the short term emission rate would be unchanged. However, if the SCR will not be in use going forward after the conversion to burn natural gas, the $NO_X$ emissions would increase on a kg/hr basis and would thus subject Unit 3 to the requirements of Subpart Da as a modified unit. If subject to Subpart Da, the unit would be subject to emission limits for $NO_X$ (1.1 lb/MWh [approximately 0.106 lb/MBtu][4]) and $SO_2$ (1.4 lb/MWh) as well as all applicable monitoring, reporting, and recordkeeping requirements.

### 4.2.2 New Fuel Gas Heaters

The new natural gas-fired fuel gas heaters are currently estimated to have a heat input per water bath heater of less than 10 MBtu/hr. Therefore, these emissions sources do not meet the definition of a subject source under NSPS.

## 4.3 MERCURY AND AIR TOXICS STANDARD (MATS)

The USEPA finalized the Mercury and Air Toxics Standard (MATS) in December of 2011. MATS establishes Maximum Achievable Control Technology (MACT) standards for mercury (Hg) and other hazardous air pollutant (HAP) emissions from existing coal and oil-fired electric generating units (EGUs) via numerical emission limits for Hg, other metallic HAPs, and acid gas HAPs. Additionally, MATS establishes work practice standards for emissions of organic HAPs (including dioxins and furans). Under the MATS rule, affected units can comply with the metallic HAPs requirements by meeting a particulate matter (PM) limit (as a surrogate for all non-Hg metallic HAPs), a total metals limit, or individual emission limits for ten different metallic HAPs, such as lead, arsenic, and various others. Compliance with acid gas limits can be demonstrated by meeting either a hydrogen chloride (HCl) emission limit, or a sulfur dioxide ($SO_2$) emission limit[5].

The E.W. Brown coal-fired units, as currently configured, are applicable to MATS. Affected sources were required to demonstrate compliance with the MATS rule by April 16, 2015 unless a one-year extension from the state permitting agency for the "installation of controls" was applied for and granted. However, MATS is only applicable to coal-fired and oil-fired electric generating units. As such, should the conversion of the facility's coal-fired units to natural gas be executed, the aforementioned emission limits and work practice standards stipulated by MATS would no longer apply[6].

## 4.4 INDUSTRIAL BOILER MACT

### 4.4.1 Existing Boilers

On January 31, 2013, the USEPA published the final reconsidered National Emission Standard for Hazardous Air Pollutants (NESHAP) for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, commonly referred to as the Industrial Boiler MACT. This rule limits HAP (or surrogates of HAPs) emissions from new and existing industrial, commercial, and institutional boilers and process heaters at major sources of HAPs and is codified under 40 CFR §63, Subpart DDDDD.

[4] Assumes a heat rate of 10,408 Btu/kWh for a natural gas-fired boiler. https://www.eia.gov/tools/faqs/faq.cfm?id=667&t=2
[5] The ability to apply the $SO_2$ limits requires that the unit have add-on flue gas desulfurization systems.
[6] 40 CFR §63.9983(c).

The emission limits found in this rule are categorized by different boiler or process heater types and fuels. Boilers and process heaters in the "units designed to burn gas 1 fuels" subcategory are not subject to the emission and operating limits in the rule. The "unit designed to burn gas 1" subcategory includes any boiler or process heater that burns only natural gas, refinery gas, and/or other gas 1 fuels (as defined in the rule). The conversion of Units 1, 2, and 3 to burn solely natural gas will classify the units into this subcategory within the rule and as stated earlier, gas 1 units are not applicable to any emission or operating limits. The units will, however, be subject to work practice standards including periodic tune-ups.

### 4.4.2 New Fuel Gas Heaters

The new natural gas-fired fuel gas heaters will be classified as "units designed to burn gas 1 fuels" and thus are not subject to the emission and operating limits in the rule. However, these units will be subject to the work practice standards including periodic tune-ups as outlined in Table 3 to 40 CFR §63, Subpart DDDDD.

## 4.5 GREENHOUSE GAS (GHG) PERFORMANCE STANDARDS

On August 3, 2015 the USEPA released its final Clean Power Plan (CPP) rulemaking to establish standards for performance for greenhouse gas emissions from existing electric generating units (EGUs) under Section 111(d) of the Clean Air Act (CAA). As finalized, the USEPA's rule seeks to reduce $CO_2$ emissions by approximately 32 percent from 2005 industry levels by 2030. In the final rule, the USEPA is setting emission performance rates, phased in over the period from 2022 through 2030, for two subcategories of affected fossil fuel-fired EGUs – fossil fuel-fired electric utility steam generating units and stationary combustion turbines.

On February 9, 2016 the United States Supreme Court issued an order to stay (suspend) the CPP until legal challenges to the rule can be settled in federal court(s). The one certain outcome of the Court's decision is that states are no longer obligated to submit initial SIP's by the September 9, 2016 deadline. Additionally, on December 19, 2016, USEPA stated they would not finalize the draft model trading rules since the rule has been stayed. Lastly, the future of the CPP has been rendered even more uncertain given the policies of the new Presidential Administration. As such, the specific impacts on E.W. Brown will not be known for some time. Regardless of the uncertainty, conversion of the E.W. Brown coal-fired units to natural gas will better position the facility to meet possible requirements in a Kentucky implementation plan, regardless of whether such a plan implements a lbs $CO_2$/MWh rate-based standard, or a more traditional mass-based cap and trade approach.

## 4.6 INTERSTATE CAP AND TRADE RULE REVISIONS

After a lengthy legal process, on January 1, 2015, the Cross-State Air Pollution Rule (CSAPR) replaced the Clean Air Interstate Rule as the EPA's cap and trade program aimed at curbing cross-state transport of $NO_X$ and $SO_2$ emissions in the eastern United States. Ultimately, the purpose of the rule is to reduce the number of $PM_{2.5}$ and ozone nonattainment areas caused by cross-state air pollution from the power sector. Under CSAPR, affected units are those that serve a generator greater than 25 MWe and produce electricity for sale. For regulated units in Kentucky, CSAPR requires that allowances are surrendered for annual emissions of $SO_2$, as well as annual and ozone season (May through September) emissions of $NO_X$.

The EPA affords utilities a degree of latitude to determine how best to integrate compliance with the emissions reduction requirements of this rule by including an allowance-trading mechanism. The air quality-assured trading remedy in the rule allows interstate trading to account for variability in the electricity sector but also includes assurance provisions to ensure that necessary emissions reductions occur within each covered state. The assurance provisions restrict EGU emissions within each state to a state-specific budget, plus the variability limit, and ensure that every state is making reductions to eliminate the significant contribution to nonattainment and interference with ambient air quality maintenance that EPA has identified.

For each affected unit, a given state allocates allowances for each regulated pollutant and compliance period (e.g., annual $SO_2$ allowances, annual $NO_X$ allowances, and ozone season $NO_X$ allowances). Any surplus allowances can be banked and held for future compliance and/or sold on the open market. Should a facility's emissions be in excess of its annual allocation, the deficit is required to be covered by banked allowances and/or allowances purchased on the open market.

The conversion of Units 1, 2, and 3 and the accompanying reduction in $SO_2$ emissions will better position E.W. Brown for interstate cap and trade compliance and potentially reduce the cost of compliance by lessening any need to purchase $SO_2$ allowances on the open market. However, the potential increase in $NO_X$ emissions may or may not offset this reduction in cost as there may be a need to purchase $NO_X$ allowances on the open market.

## 4.7 POSSIBLE EFFECTS ON AIR DISPERSION MODELING

Should the project trigger PSD major source permitting requirement, an air dispersion modeling analysis would be required for each applicable PSD pollutant[7].However, even in the event that the proposed project were able to be considered a minor modification, KYDEP reserves the right to request an air dispersion modeling analysis at their discretion, should they deem it necessary to verify that the project will not detrimentally affect the ambient air quality. Key parameters that directly affect the ground level impacts of the facility's emissions would be changing as a result of certain aspects of the modification (including the halt in operation of $SO_2$ and PM controls). These parameters are listed below:

- Stack location
- Emission Rates
- Exhaust Gas Temperature
- Exhaust Flow(acfm) and/or Exhaust Stack Exit Velocity

It is possible that these changes could prompt the KYDEP to request a modeling analysis. As such, an intelligence-gathering exploratory modeling analysis may be prudent once the project design is

[7] Air dispersion modeling is not required for emissions of VOC or GHG.

more refined in order to determine what affect the changing of these parameters would have on the modeled impact of the project and/or facility.

## 4.8 TITLE V OPERATING PERMIT MODIFICATION

The Division for Air Quality within the Department for Environmental Protection issues a single Title V permit to both construct and operate. A major revision to the existing Title V permit would be required based on the emission estimates listed above in this section. Applying for this major revision can be a lengthy process (i.e., 12-18 months) and is paramount to allow time in the schedule to receive this permit.

# 5.0 Capital Cost Estimates

This section presents the estimated costs associated with implementing the modifications necessary to allow operation of the units on natural gas. The cost estimate includes estimated costs for equipment and materials, construction labor, engineering services, construction management, indirect costs, and other costs. Provided costs are order of magnitude +/- 30% cost estimates. These types of estimates are screening level estimates prepared for the purposes of project screening, resource planning, comparison of alternative technologies, etc. These types of estimates are created using historic information from similar projects and are modified (to the extent that the scope of work is known) by also using historic project information. Material and subcontract estimates are made using recent pricing information, estimated wage rates, and productivity factors from general industry data or recent projects.

The cost-provided information is consistent with recent experience and market conditions, but as demonstrated in the last few years, the market can be dynamic and unpredictable. Power plant costs will be subject to continued volatility in the future, and the estimates in this report should be considered primarily for comparative purposes.

## 5.1 COST ESTIMATE BASIS

### 5.1.1 Scope of Work and Basis of Estimate

The scope of work for this study is based on the descriptions provided in Section 3.0 of this report. The estimate is based on past Black & Veatch projects and engineering estimates and burner quotations received from multiple burner suppliers.

### 5.1.2 Direct Costs

All costs represent 2017 overnight pricing. Material and pricing is based on published values and recent budgetary quotes from vendors. Contingency is calculated on a weighted basis, representing areas of risk and unknowns, and presented as a one-line entry.

- Capital cost estimates are based on an engineering, procurement, and construction (EPC) contracting methodology.
- Start up and commissioning costs are included and estimated to be the cost associated with QA/QC turnover books, initial operator training, and operational testing by the EPC contractor.
- The cost estimates are provided in 2017 dollars. No escalation is included.
- Direct costs include the costs associated with the purchase of equipment, equipment erection, equipment supplier's technical advisory services during erection, and contractors' services.
- An allowance for remediation of Hazardous Material (Lead paint, asbestos) is included in the cost estimate.

- An allowance for reclassification of existing Electrical items (based on number of fixtures to be relocated or replaced and extent of conduit to be relocated or replaced to different classification requirements) is included in the cost estimate.
- An allowance for transportation and delivery of equipment to the jobsite is included in the cost estimate.

### 5.1.3 Indirect Costs

Indirect costs are estimated as a percentage of direct costs based on past project experience. Estimated indirect costs are intended to capture the following:

- Mobilization and demobilization.
- Temporary construction.
- Temporary facilities.
- Field supervision and expenses.
- Field office equipment and supplies.
- Construction equipment usage.
- Small tools and consumables.
- Health and safety.
- Construction security.
- Construction testing.
- EPC contractor's overhead and profit.
- Engineering and project administration.
- EPC construction management.
- Permits and fees.
- Project insurance.
- Performance bond.

### 5.1.4 Assumptions

The following are assumptions used for the estimate:

- Normal lead times for equipment deliveries are experienced.
- Construction utilities (power, water, air) are provided by the Owner.
- No design optimization has been performed for this conceptual design.
- Natural gas fuel properties are as provided by LG&E KU.
- No analysis of hydrate formation or other temperature effects has been performed.
- Off-site supply natural gas pipe size is chosen to limit natural gas velocity to 7,500 ft/min (common for natural gas branch lines) and includes a 10 percent flow margin.
- In-plant natural gas pipe sizes are chosen to limit natural gas velocity to 7,500 ft/min (Black & Veatch standard for in-plant natural gas piping) and include a 10 percent flow margin.
- All equipment is assumed to have been maintained in serviceable and operable condition.

### 5.1.5 Exclusions

The estimate does not include any costs for the following:

- Cost of natural gas or electricity during construction, testing and commissioning.
- Spare parts.
- Undefined underground obstructions.
- Owner's costs.
- Allowance for Funds Used for Construction.
- Sales/use taxes.
- Environmental permitting and construction licensing.

The cost estimates in this study only account for converting the E.W. Brown units from coal to natural gas. Estimates do not account for capital, operation and maintenance costs that might be incurred as a result of extending the life of the units beyond current retirement plans.

## 5.2 COST ESTIMATE

Order of magnitude cost estimates are provided in Table 5-1.

**Table 5-1 Order of Magnitude Cost Estimates**

| Description | Unit 1 Conversion Cost (Material and Labor) | Unit 2 Conversion Cost (Material and Labor) | Unit 3 Conversion Cost (Material and Labor) | Balance of Plant (Material and Labor) | Total |
|---|---|---|---|---|---|
| Direct Costs (DC) | | | | | |
| - | | | | | |
| Burner Equipment | | | | | |
| Burners, SOFA, FGR System, Gas regulation and metering, Heater | $7,415,000 | $3,915,000 | $6,300,000 | $0 | $17,630,000 |
| CEMS Equipment | | | | $325,000 | $325,000 |
| Boiler Study | $300,000 | $300,000 | $300,000 | $0 | $900,000 |
| Subtotal: Equipment Costs | $7,715,000 | $4,215,000 | $6,600,000 | $325,000 | $18,855,000 |
| Lighting, Communications, Receptacles | $28,700 | $28,700 | $81,600 | $0 | $139,000 |
| Electrical Power Distribution Equipment | $47,400 | $50,800 | $63,400 | $0 | $161,600 |
| DCS | $600,000 | $580,000 | $725,000 | $0 | $1,905,000 |
| Conduit | $64,000 | $70,600 | $105,800 | $0 | $240,400 |
| Power Cable | $9,900 | $11,000 | $16,400 | $0 | $37,300 |
| Control Cable | $9,500 | $10,400 | $15,600 | $0 | $35,500 |
| Terminations | $47,300 | $52,200 | $78,200 | $0 | $177,700 |
| Coal Pipe Demolition | $114,000 | $171,000 | $256,500 | $0 | $541,500 |
| 24" Gas Pipe Line from Plant Boundary | | | | $3,766,800 | $3,766,800 |
| River crossing boring/pipe supports | | | | $135,000 | $135,000 |
| Above Grade CS: 18" Schedule 40 (Gas Supply) | | $116,300 | $232,400 | $0 | $348,700 |
| Above Grade CS: 14" Schedule 40 (Gas Supply) | | | $143,800 | $0 | $143,800 |
| Above Grade CS: 12" Schedule 40 (Gas Supply) | $59,100 | $0 | $0 | $0 | $59,100 |
| Above Grade CS: 10" Schedule 40 (Gas Supply) | | $277,800 | $185,400 | $0 | $463,200 |
| Above Grade CS: 8" Schedule 40 (Gas Supply) | $69,700 | $0 | $0 | $233,500 | $303,200 |
| Above Grade CS: 6" Schedule 40 (Gas Supply) | $79,800 | $203,400 | $283,200 | $0 | $566,400 |
| Above Grade CS: 3" Schedule 40 (Gas Supply) | $119,900 | $0 | $0 | $0 | $119,900 |
| Ductwork | $341,400 | $25,800 | $2,329,000 | $0 | $2,696,200 |
| Existing Ductwork Modifications | $7,600 | $7,600 | $7,600 | $0 | $22,800 |
| Structural Steel | $142,600 | $10,800 | $971,700 | $0 | $1,125,100 |

| Description | Unit 1 | Unit 2 | Unit 3 | Balance of | Total |
|---|---|---|---|---|---|
| Grating | $208,000 | $208,000 | $311,800 | $0 | $727,800 |
| Handrail | $30,200 | $30,200 | $45,200 | $0 | $105,600 |
| Foundations and Civil Works | | | | $1,442,000 | $1,442,000 |
| Equipment Installation | $550,000 | $550,000 | $550,000 | $190,000 | $1,840,000 |
| Construction Equipment, Temp Facility, and Indirect Supervision | $1,795,000 | $1,795,000 | $3,240,000 | $1,560,000 | $8,390,000 |
| Start-Up & Commissioning (7,000 Hours) | $432,000 | $432,000 | $432,000 | $200,600 | $1,496,600 |
| Subtotal: Construction | $4,756,100 | $4,631,600 | $10,074,600 | $7,527,900 | $26,990,200 |
| 30" Gas Pipe Line to Plant Boundary to connection station | | | | | |
| Excavation (soil 40%) | | | | $234,100 | $234,100 |
| Excavation (rock 60%) | | | | $468,200 | $468,200 |
| Sand Bedding 3" deep | | | | $33,500 | $33,500 |
| Backfill (soil) | | | | $374,500 | $374,500 |
| Backfill (import) | | | | $578,200 | $578,200 |
| Spoil Haul off-site | | | | $1,440,100 | $1,440,100 |
| Small road crossing 30" | | | | $22,200 | $22,200 |
| Highway 27 road crossing 30" HDD | | | | $500,000 | $500,000 |
| U/G CS: 30" Schedule 40 (main gas offsite) | | | | $10,950,700 | $10,950,700 |
| Rig Welder equipment | | | | $3,000,000 | $3,000,000 |
| NDE x-ray | | | | $1,663,200 | $1,663,200 |
| Trench Box rental | | | | $48,000 | $48,000 |
| Equipment | | | | $912,700 | $912,700 |
| Pot holing with Hydro Excavator | | | | $2,500,000 | $2,500,000 |
| Off-site Indirect Supervision | | | | $5,575,800 | $5,575,800 |
| Subtotal: Off-site Gas Pipe Line | | | | $28,301,200 | $28,301,200 |
| Electrical Re-Classification of hazardous areas | $150,000 | $150,000 | $250,000 | $0 | $550,000 |
| Scaffolding Subcontractor | $585,000 | $585,000 | $585,000 | $0 | $1,755,000 |
| Subtotal: Allowance | $735,000 | $735,000 | $835,000 | $0 | $2,305,000 |
| **Total Direct Costs (DC)** | **$13,206,100** | **$9,581,600** | **$17,509,600** | **$36,154,100** | **$76,451,400** |

| Description | | Unit 1 | Unit 2 | Unit 3 | Balance of | Total |
|---|---|---|---|---|---|---|
| Indirect Costs | | | | | | |
| Engineering | 10% x DC | $1,320,610 | $958,160 | $1,750,960 | $3,615,410 | $7,645,140 |
| Contingency | 15% x DC | $1,980,915 | $1,437,240 | $2,626,440 | $5,423,115 | $11,467,710 |
| Overhead and Profit | 15% x DC | $1,980,915 | $1,437,240 | $2,626,440 | $5,423,115 | $11,467,710 |
| **Total Indirect Costs (IC)** | | **$5,282,440** | **$3,832,640** | **$7,003,840** | **$14,461,640** | **$30,580,560** |
| **Total Capital Investment (TCI) = (DC) + (IC)** | | **$18,488,540** | **$13,414,240** | **$24,513,440** | **$50,615,740** | **$107,031,960** |
| **Tax** | | | | | | **$0** |
| **Insurance, & Bonds** | 2% | | | | | **$2,140,639** |
| **Hazardous Material Abatement Allowance** | | | | | | **$1,000,000** |
| **Owner Costs** | 5% | | | | | **$5,351,598** |
| **Total Project Costs** | | | | | | **$115,524,197** |

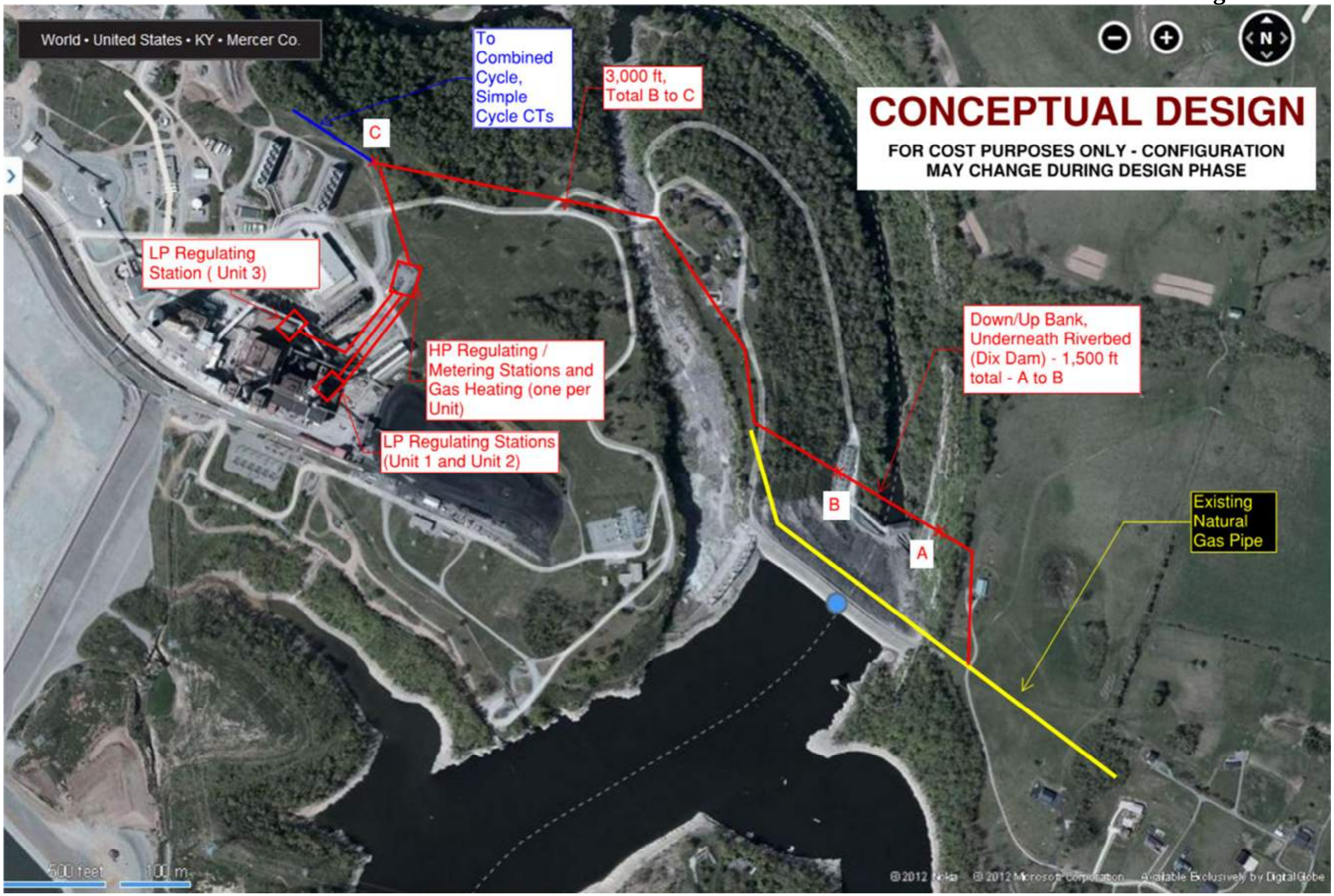
| Description | Unit 1 | Unit 2 | Unit 3 | Balance of | Total |
|---|---|---|---|---|---|
| **Potential Budgetary Cost Adjustments** | | | | | |
| 20" gas line from plant boundary | | | | | **-$812,000** |
| Boiler Heating Surface Modifications to achieve Full Load Unit Output (Allowance) | $6,000,000 | $7,000,000 | $10,000,000 | | |

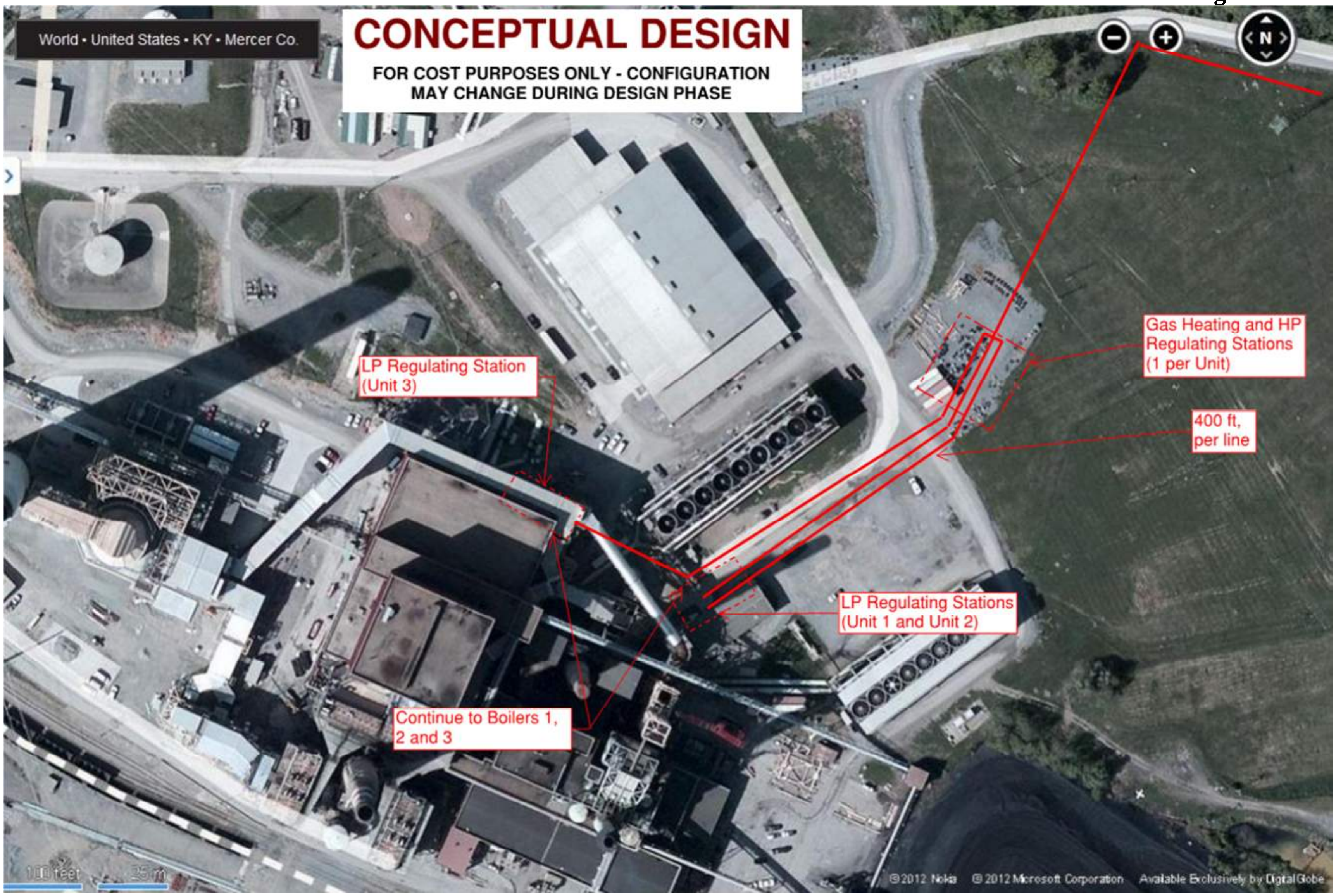
# 6.0 Preliminary Project Schedule

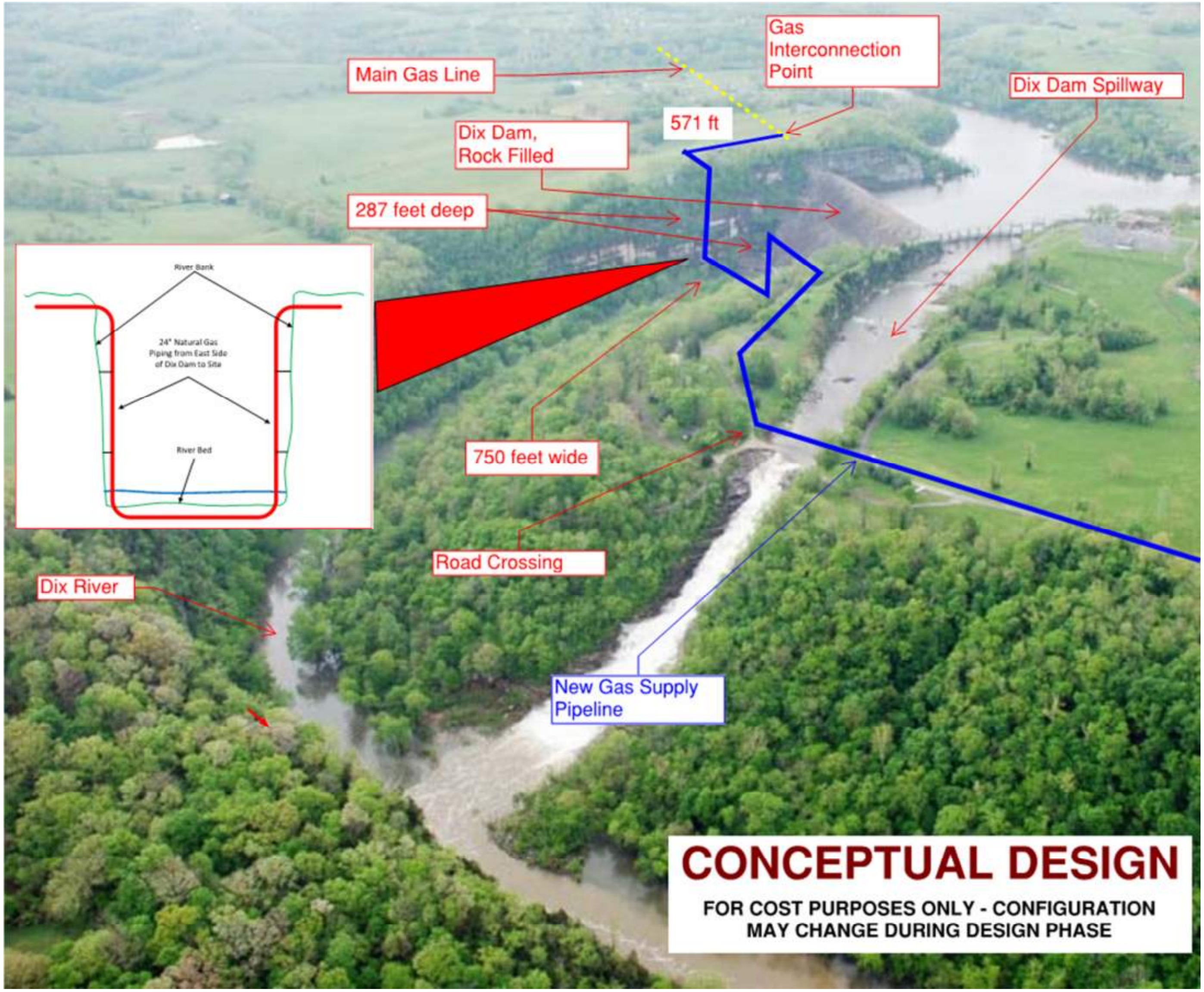
A Level 1 project schedule covering engineering, procurement, construction, and startup activities is presented in Appendix D. The schedule illustrates the key activities in engineering, procurement, and construction to incorporate the system modifications to convert the units to natural gas. This initial schedule represents a timeline from release of engineering through commissioning.

The durations shown for all the activities, except the outage installation and post outage testing and tuning activities, encompass the design and procurement activities required to modify each unit. The durations shown for the outage installation and post outage testing and tuning activities encompass the work required to modify just one of the three units. Scheduling of the outage and post outage work for each unit is constrained by the timing of the tie-in outages.

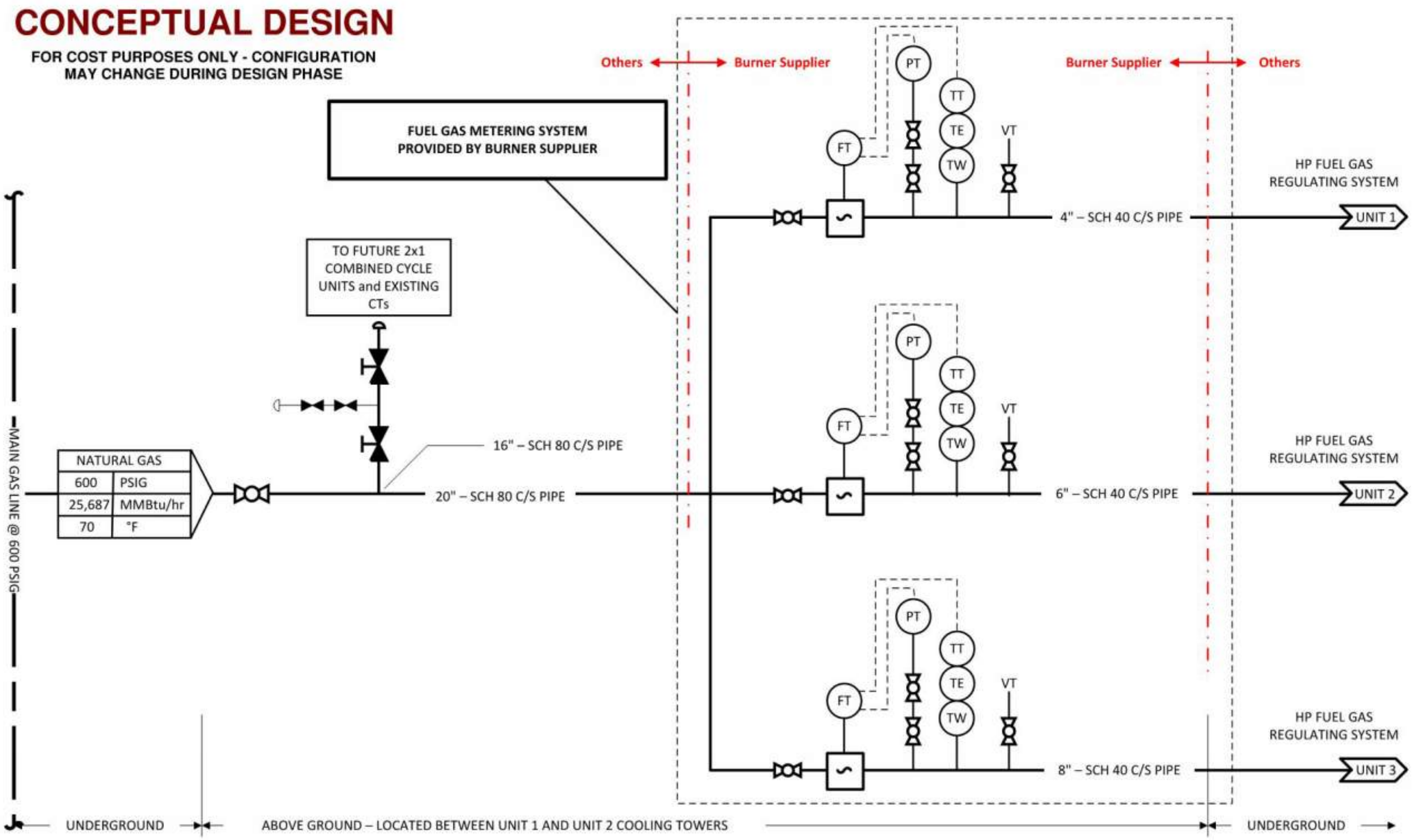
# Appendix A. Natural Gas Pipeline Preliminary Routing


World • United States • KY • Mercer Co.
To Combined Cycle, Simple Cycle CTs
3,000 ft, Total B to C
CONCEPTUAL DESIGN
FOR COST PURPOSES ONLY - CONFIGURATION MAY CHANGE DURING DESIGN PHASE
C
LP Regulating Station ( Unit 3)
HP Regulating / Metering Stations and Gas Heating (one per Unit)
LP Regulating Stations (Unit 1 and Unit 2)
Down/Up Bank, Underneath Riverbed (Dix Dam) - 1,500 ft total - A to B
B
A
Existing Natural Gas Pipe
500 feet
100 m
© 2012 Nokia © 2012 Microsoft Corporation Available Exclusively by DigitalGlobe


World • United States • KY • Mercer Co.
CONCEPTUAL DESIGN
FOR COST PURPOSES ONLY - CONFIGURATION MAY CHANGE DURING DESIGN PHASE
LP Regulating Station (Unit 3)
Gas Heating and HP Regulating Stations (1 per Unit)
400 ft, per line
LP Regulating Stations (Unit 1 and Unit 2)
Continue to Boilers 1, 2 and 3
100 feet
25 m
©2012 Nokia ©2012 Microsoft Corporation Available Exclusively by DigitalGlobe

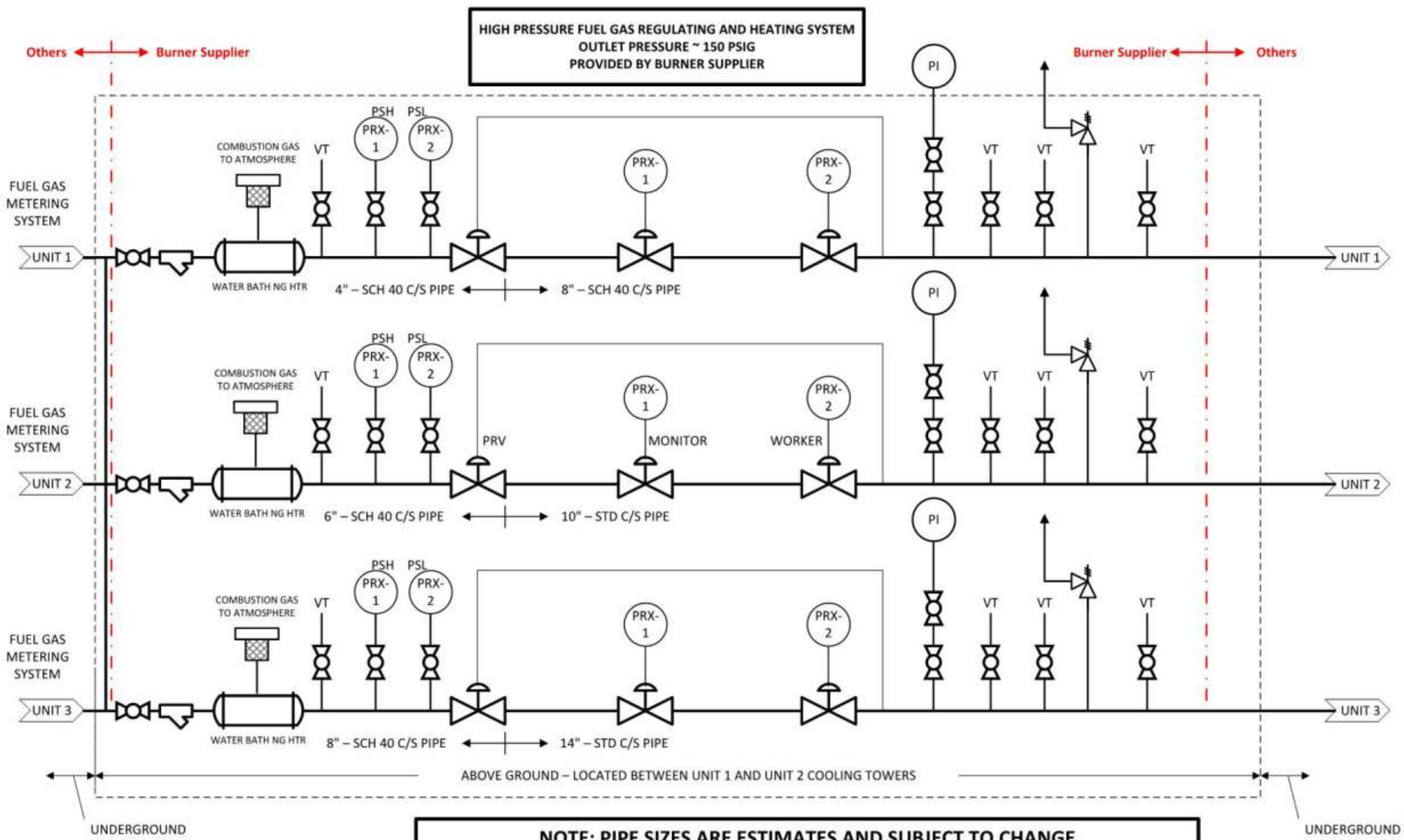

Main Gas Line
Gas Interconnection Point
Dix Dam Spillway
571 ft
Dix Dam, Rock Filled
287 feet deep
River Bank
24" Natural Gas Piping from East Side of Dix Dam to Site
River Bed
750 feet wide
Road Crossing
Dix River
New Gas Supply Pipeline
CONCEPTUAL DESIGN
FOR COST PURPOSES ONLY - CONFIGURATION MAY CHANGE DURING DESIGN PHASE

# Appendix B. Flow Diagrams




NOTE: ALL VALVES TO BE FLANGED

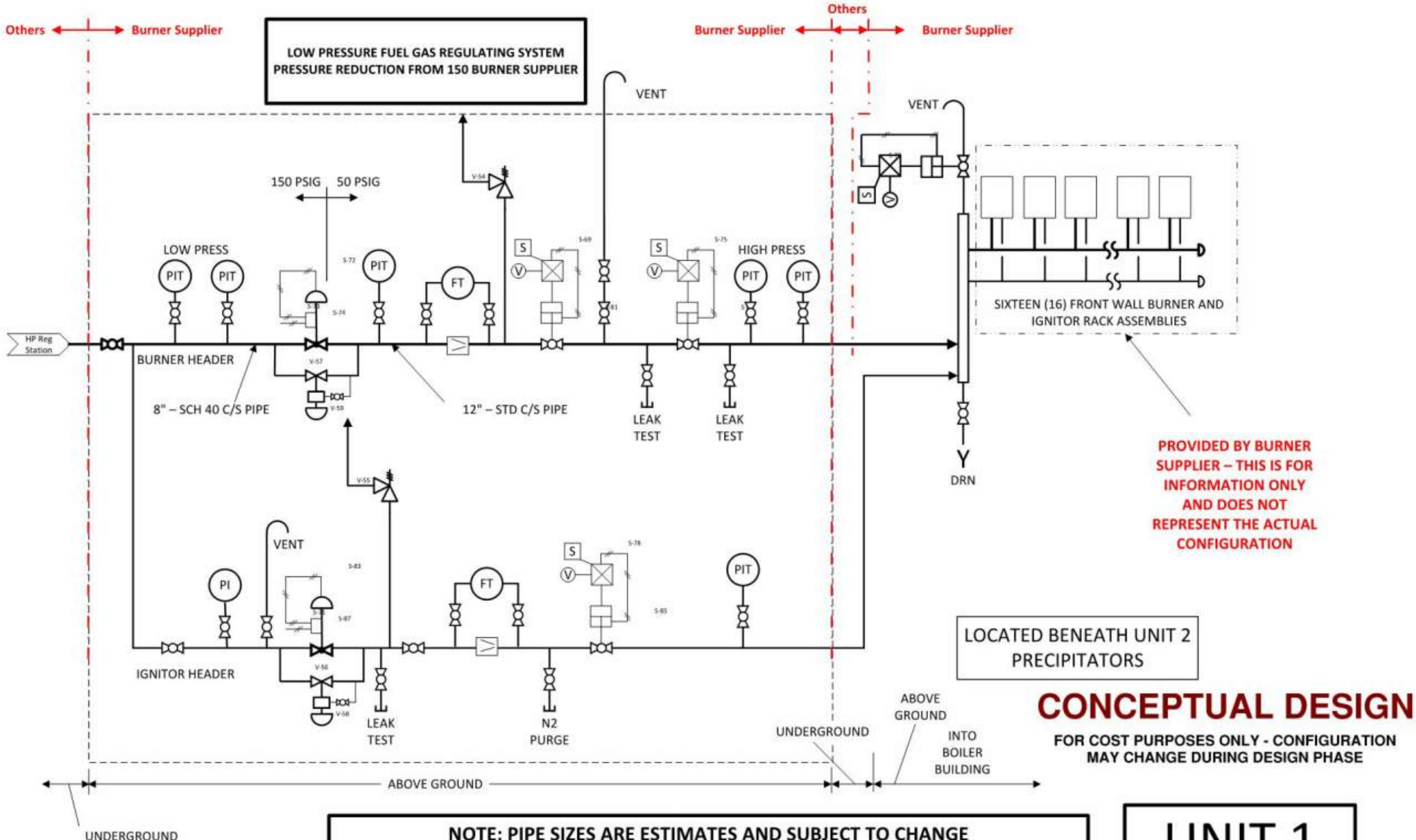
**NOTE: PIPE SIZES ARE ESTIMATES AND SUBJECT TO CHANGE**
**ALL PIPE IS PER API 5L W/ 14 MIL AVERAGE F.B.E. ABOVE GROUND IS NOT COATED.**




NOTE: PIPE SIZES ARE ESTIMATES AND SUBJECT TO CHANGE
ALL PIPE IS PER API 5L W/ 14 MIL AVERAGE F.B.E. ABOVE GROUND IS NOT COATED.

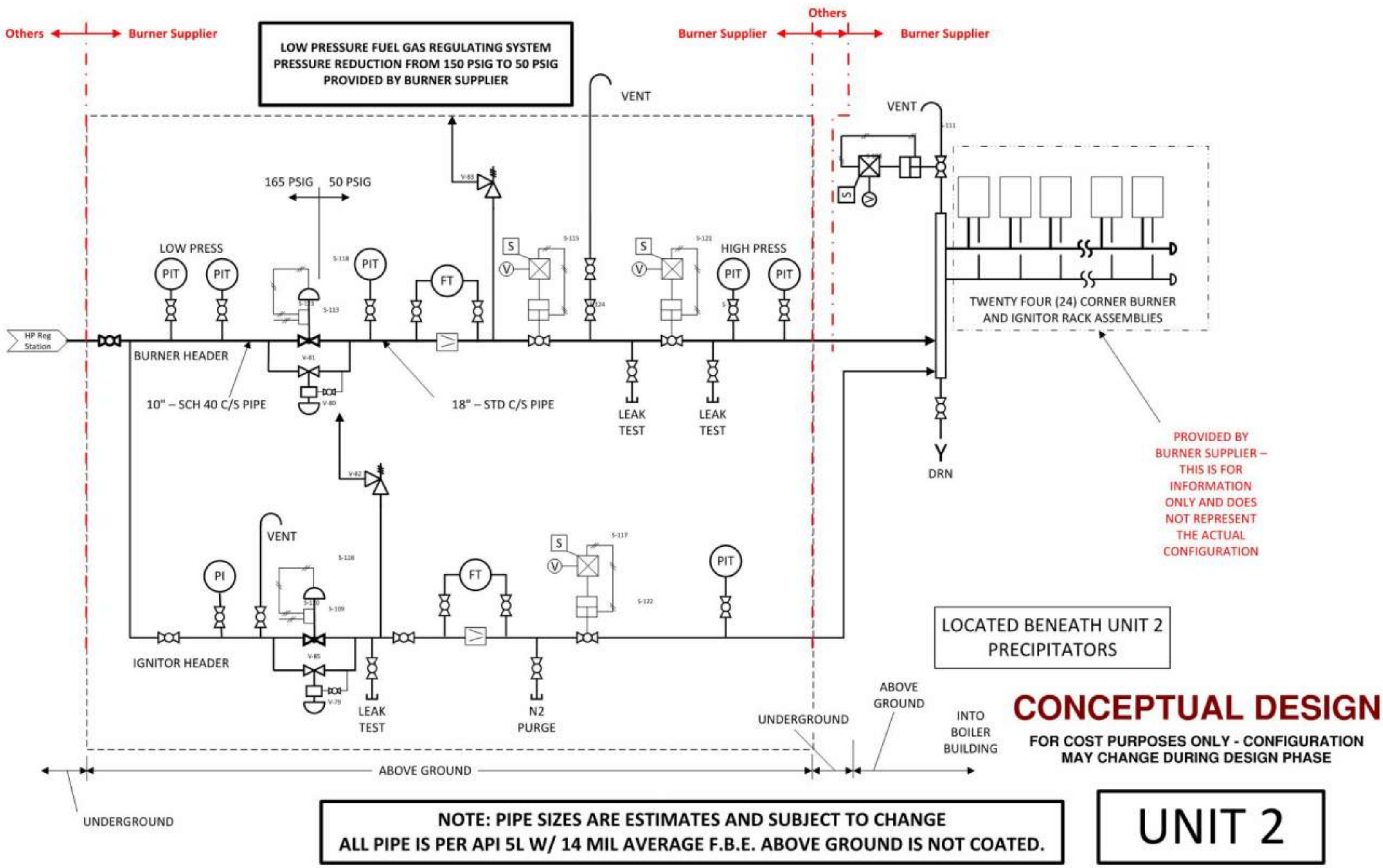
**CONCEPTUAL DESIGN**

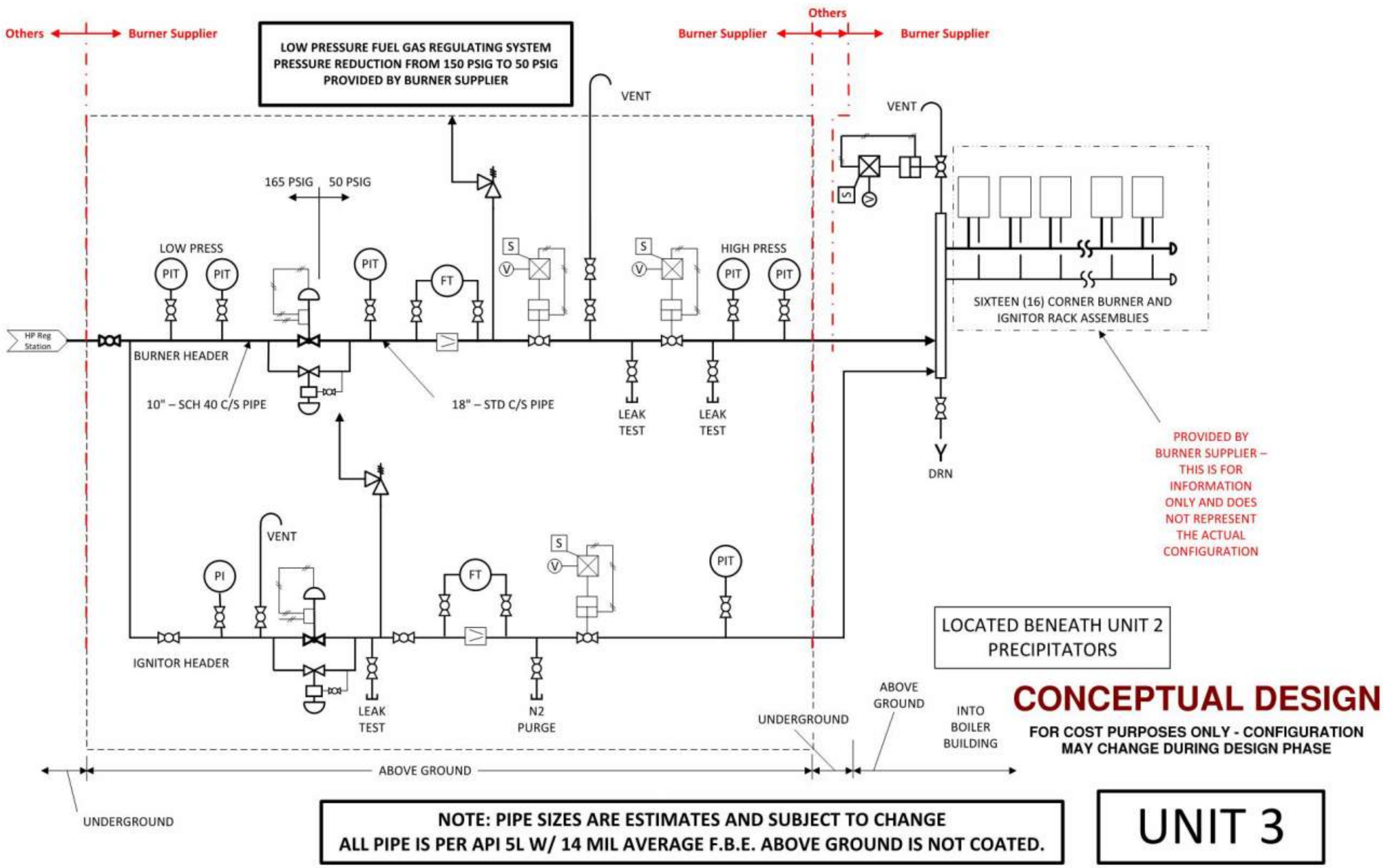
FOR COST PURPOSES ONLY - CONFIGURATION MAY CHANGE DURING DESIGN PHASE




NOTE: PIPE SIZES ARE ESTIMATES AND SUBJECT TO CHANGE
ALL PIPE IS PER API 5L W/ 14 MIL AVERAGE F.B.E. ABOVE GROUND IS NOT COATED.

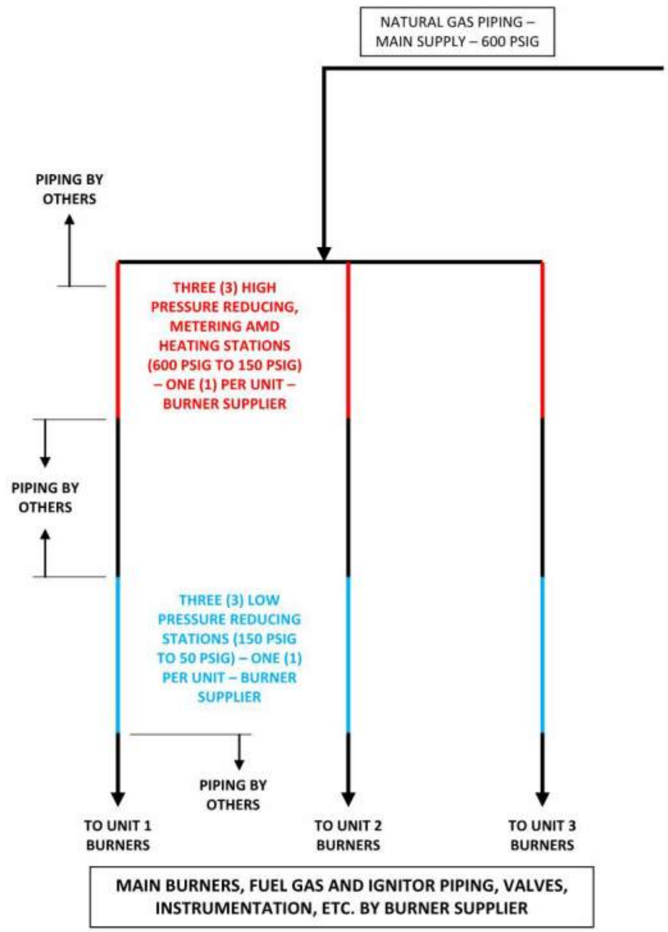
UNIT 1


Others
Burner Supplier
LOW PRESSURE FUEL GAS REGULATING SYSTEM
PRESSURE REDUCTION FROM 150 PSIG TO 50 PSIG
PROVIDED BY BURNER SUPPLIER
Burner Supplier
Others
Burner Supplier
VENT
VENT
165 PSIG
50 PSIG
LOW PRESS
HIGH PRESS
PIT
FT
HP Reg Station
BURNER HEADER
10" – SCH 40 C/S PIPE
18" – STD C/S PIPE
LEAK TEST
LEAK TEST
TWENTY FOUR (24) CORNER BURNER AND IGNITOR RACK ASSEMBLIES
DRN
PROVIDED BY BURNER SUPPLIER – THIS IS FOR INFORMATION ONLY AND DOES NOT REPRESENT THE ACTUAL CONFIGURATION
VENT
PI
IGNITOR HEADER
LEAK TEST
N2 PURGE
LOCATED BENEATH UNIT 2 PRECIPITATORS
ABOVE GROUND
UNDERGROUND
INTO BOILER BUILDING
ABOVE GROUND
UNDERGROUND
CONCEPTUAL DESIGN
FOR COST PURPOSES ONLY - CONFIGURATION MAY CHANGE DURING DESIGN PHASE
NOTE: PIPE SIZES ARE ESTIMATES AND SUBJECT TO CHANGE
ALL PIPE IS PER API 5L W/ 14 MIL AVERAGE F.B.E. ABOVE GROUND IS NOT COATED.
UNIT 2


Others
Burner Supplier
LOW PRESSURE FUEL GAS REGULATING SYSTEM
PRESSURE REDUCTION FROM 150 PSIG TO 50 PSIG
PROVIDED BY BURNER SUPPLIER
Burner Supplier
Others
Burner Supplier
VENT
VENT
165 PSIG
50 PSIG
LOW PRESS
PIT
PIT
PIT
FT
S
V
HIGH PRESS
PIT
PIT
HP Reg Station
BURNER HEADER
10" – SCH 40 C/S PIPE
18" – STD C/S PIPE
LEAK TEST
LEAK TEST
DRN
SIXTEEN (16) CORNER BURNER AND IGNITOR RACK ASSEMBLIES
PROVIDED BY BURNER SUPPLIER – THIS IS FOR INFORMATION ONLY AND DOES NOT REPRESENT THE ACTUAL CONFIGURATION
VENT
PI
FT
PIT
IGNITOR HEADER
LEAK TEST
N2 PURGE
LOCATED BENEATH UNIT 2 PRECIPITATORS
ABOVE GROUND
INTO BOILER BUILDING
UNDERGROUND
ABOVE GROUND
UNDERGROUND
CONCEPTUAL DESIGN
FOR COST PURPOSES ONLY - CONFIGURATION MAY CHANGE DURING DESIGN PHASE
NOTE: PIPE SIZES ARE ESTIMATES AND SUBJECT TO CHANGE
ALL PIPE IS PER API 5L W/ 14 MIL AVERAGE F.B.E. ABOVE GROUND IS NOT COATED.
UNIT 3

# CONCEPTUAL DESIGN

FOR COST PURPOSES ONLY - CONFIGURATION MAY CHANGE DURING DESIGN PHASE



# Appendix C. Supplier Quotes and Proposal Comparison

| LG&E KU Gas Burner Proposal Comparison | GE | STEP | Babcock Power | Locke | IHI |
|---|---|---|---|---|---|
| **PRICE BREAKDOWN** | | | | | |
| Project Management/Engineering | N/A | $90,000 | N/A | N/A | N/A |
| Replacement Burners | N/A | $450,000 | N/A | N/A | $ 5,400,000 |
| Igniters | N/A | $174,000 | N/A | N/A | N/A |
| Flame Scanners | N/A | $150,000 | N/A | N/A | N/A |
| SOFA System (If applicable) | N/A | $197,000 | N/A | N/A | N/A |
| Fuel Supply System Modifications | N/A | $360,000 | N/A | N/A | N/A |
| Flue Gas Recirculation system (if applicable) | N/A | $350,000 | N/A | N/A | N/A |
| Integrated Flue Gas Recirculation system (if applicable) | N/A | $240,000 | N/A | N/A | N/A |
| Freight | N/A | $10,000 | N/A | N/A | N/A |
| **Total Burners Only** | **$1,825,000** | **$1,234,000** | **$1.5M to 2M** | **$ 4,350,000** | **$5,400,000** |
| Total Burners + SOFA (Unit 3 has SOFA in place) | N/A | $1,431,000 | N/A | N/A | N/A |
| Total Burners + SOFA + FGR | N/A | $1,781,000 | N/A | N/A | N/A |
| Total Burners + SOFA + IFGR | N/A | $1,671,000 | N/A | N/A | N/A |
| **Lead time** | **40 to 42 weeks** | **18 weeks** | **N/A** | **36 to 42 weeks** | **48 weeks** |
| Shipment | Delivered At Place (DAP) Harrodsburg, KY | Delivered to Site | N/A | Delivered to Site | Ex-Works Factory |
| **EQUIPMENT** | | | | | |
| Low $NO_x$ Burners | | | | | |
| New Burners (number) | 16 gas burners rated for 270 MBtu/hr (4 burner elevs) | Upgrade existing 20 coal burners to Low $NO_x$ Natural Gas Burners | N/A | 20 low box $NO_x$ burner, 242 MBtu/hr | 16 burners (4 elevs) |
| Separated Overfire Air System. (if applicable) | | | | | |
| Number of ports | N/A | 4 | N/A | N/A | N/A |
| FGR System (if applicable) | | | | | |
| % FGR | N/A | 10 | N/A | N/A | N/A |

| LG&E KU Gas Burner Proposal Comparison | GE | STEP | Babcock Power | Locke | IHI |
|---|---|---|---|---|---|
| Fan HP | N/A | 1 Variable Speed Fan with discharge pressure of 10 inw | N/A | N/A | N/A |
| Ignitor Equipment | | | | | |
| Number provided | 16 LIMELIGHT™ | 20 Forney Max Fire | N/A | 20 FyrBolt igniters | 16 |
| Type | Gas Side | Class 1 | N/A | | Class 1 |
| Capacity, MBtu/hr | 6 MBtu/hr | 10% Heat Input | N/A | 12 MBtu/hr | 25 MBtu/hr |
| | | | | | |
| Flame Scanner Equipment | | | | | |
| Number provided | 16 LIMELIGHT™ Exacta VL flame scanners | 40 (2 per burner) | N/A | 20 | 16 |
| Type | Visible Light | Visible Light | N/A | Visible Light | Visible Light |
| **TS 1.3 PERFORMANCE** | | | | | |
| Load, % of MCR | | | | | |
| Fuel Flow, MBtu/hr | | | | | |
| Primary Air, lb/hr | | | | | |
| Secondary Air, lb/hr | | | | | |
| SOFA split % of total air | | | | | |
| $O_2$ | | | | | |
| **TS 1.4 EMISSIONS (Full Load)** | | | | | |
| Burners Only | | | | | |
| $NO_x$, lb/MBtu | N/A | 0.2 | N/A | 0.42 | 0.25 to 0.40 |
| CO, lb/MBtu | N/A | 0.15 | N/A | 0.074 | <150 ppm @ 3% $O_2$, dry |
| Burners + SOFA | | | | | |
| $NO_x$, lb/MBtu | <0.1 | 0.15 | N/A | N/A | 0.08 to 0.12 |
| CO, lb/MBtu | <0.15 | 0.15 | N/A | N/A | <150 ppm @ 3% $O_2$, dry |
| Burners + FGR | | | | | |
| $NO_x$, lb/MBtu | N/A | 0.13 | N/A | N/A | N/A |

| LG&E KU Gas Burner Proposal Comparison | GE | STEP | Babcock Power | Locke | IHI |
|---|---|---|---|---|---|
| CO, lb/MBtu | N/A | 0.15 | N/A | N/A | N/A |
| Burners + FGR + SOFA | | | | | |
| $NO_x$, lb/MBtu | N/A | 0.1 | N/A | 0.1 | N/A |
| CO, lb/MBtu | N/A | 0.15 | N/A | 0.074 | N/A |
| **TS 1.5 SCOPE OF SUPPLY** | | | | | |
| CFD Modeling | No | Yes | N/A | Yes | Yes, use internal proprietary software |
| Burner Replacement | Yes | Yes | Yes | Yes | Yes |
| Secondary air modifications | Yes | Yes | N/A | Yes | Yes |
| Igniters | Yes | Yes | Yes | Yes | Yes |
| Scanners | Yes | Yes | Yes | Yes | Yes |
| SOFA System | No | Yes | No | No (Re-Use) | No (Re-Use) |
| FGR System | No | Yes | No | No | No |
| Logic diagrams | Yes, Contract Phase | Yes | N/A | Yes | Yes |
| I/O List | Yes, Contract Phase | Yes | N/A | Yes | Yes |
| System Operating Description | Yes, Contract Phase | Yes | N/A | Yes | Yes |
| Pressure Reducing and Metering Skids (3) | No, (1) Main gas & Ignitor Gas Skid per unit | Yes | Yes | Yes | Yes |
| Burner Control Piping Skids (3) | No, loose | Yes | N/A | Yes | Yes |
| Platforms | No | No | N/A | No | No |
| Hangers | No | No | N/A | No | No |
| Intermediate support steel for hangers | No | No | N/A | No | No |
| Field Service Included | No, need outage length | Yes | N/A | Yes | Yes |
| Number of man days | N/A | 30 | N/A | 20 | 64 |
| Number of round trips | N/A | 8 | N/A | 2 | 7 |

| LG&E KU Gas Burner Proposal Comparison | GE | STEP | Babcock Power | Locke | IHI |
|---|---|---|---|---|---|
| Guarantees | Not included in proposal | Not included in proposal | Not included in proposal | PG Test conducted 60 days upon delivery or 30 days from installation.<br>• Guarantee on maximum burner heat output<br>• Guarantee on emission for $NO_x$, CO, and opacity< 10% (6 min rolling avg)<br>• Max noise guarantee of 85 dBa | Guarantees on economizer gas temperature, $NO_x$, and CO |
| Warranty | Not included in proposal | Not included in proposal | Not included in proposal | Not included in proposal | 12 months on parts ONLY |

# Natural Gas Addition/Conversion Project

Black & Veatch Corporation for:
Confidential Client Units 1, 2 & 3

Alstom Power Inc., a GE Power Company
200 Great Pond Drive
Windsor, CT 06095

Proposal Number: 1147519 Rev 1
January 13, 2017

# Proprietary Statement

This entire commercial and technical proposal, Proposal 1147519 R1, and the correspondence and communications concerning this proposal, collectively the "Proposal", developed by Alstom Power Inc., a wholly owned subsidiary of the General Electric Company and a GE Power Services business, (hereafter referred to as "GE" or the "Company") and provided to Black & Veatch Corporation (hereafter referred to as "B&V" or the "Purchaser") are the property of GE.

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## Our Vision

GE Power Services is the foremost supplier of services in the energy industry. We are committed to meeting the present and future services needs of energy companies. As we develop new products and service technologies we continue to drive Six Sigma quality into all our processes. We continually acquire new skills to expand our offerings and are becoming more flexible, innovative, and customer focused.

## Who We Are

GE Power Services is a market-focused, customer-driven organization providing maintenance, engineered uprates, outage services and repairs of power systems worldwide. Superior customer service is at the heart of our business. GE Power Services' customers generate and use power in highly engineered processes, thus reliability and productivity are paramount.

We offer our customers world-class engineering services, backed by over 100 years of experience. Our experienced field engineers are highly motivated and dedicated professionals. They provide customers with superior technical innovation, problem solving, and sound project management, and are backed by a highly skilled team of service managers and technical support engineers. Our Field Engineering expertise is available 24 hours a day, 365 days a year.

Throughout GE Power Services, the climate for technical innovation has never been more exciting or demanding. Technical excellence through engineering has been the driving force behind GE's 100-year record of success. Thomas Edison, the founder of General Electric, left a legacy of entrepreneurship and inventiveness that is embodied in the specialized training programs our engineers and field engineers undergo. The result of these training programs is the ability for GE Power Services to provide its customers with the "best and brightest" engineering team available. All of our Field Engineers are equipped with lap top computers that allow access to our product service department and personnel. Our value to you as a service organization is measured by our ability to control outage extensions, minimize emergency work, and avoid work scope omissions.

# Executive Summary

January 13, 2017

Mr. Tom Trimble
Black & Veatch Corporation
11401 Lamar Avenue
Overland Park, KS 66211

Re: Confidential Client Units 1, 2 & 3
Natural Gas Addition/Conversion
Proposal 1147519, Rev 1

Dear Mr. Trimble,

In response to Black & Veatch's request to provide a budget proposal for Natural Gas Conversions for Confidential Client Units 1, 2 & 3, Alstom Power Inc., a GE Power Company is pleased to submit this revised budget proposal. This revision removes coal firing capability from the unit 1 wall fired burners. The proposed material and services are intended for use on one (1) B&W wall fired unit and two (2) Alstom/GE tangentially-fired units.

Included in this offer are material and services to convert the wall fired and T-fired burners to natural gas. Main gas and ignitor gas header valves and instrumentation will be mounted and prewired to a skid. Typical inlet pressure to this skid would the around 50 – 75 psig. Corner burner and ignitor valves and instrumentation have been supplied loose for this offering. During a firm priced offer it could be investigated supplying corner skids given adequate space for installation. Adding corner skids could range about $40K - $50k per skid.

GE is confident that this scope, as prepared and commented on by our technical staff, is complete and contains all the elements necessary to assure quality performance, in a timely manner and at a reasonable cost to the Confidential Client.

GE would like to thank you for providing the opportunity to support this project. If you have any questions, please contact me at 860-285-9986 or Mathew Norgard at 865-237-2279.

Sincerely,

| | |
|---|---|
| Submitted by | Alstom Power Inc. |
| Name | Jim Bialo |
| Title | Lead Commercial Proposal Manager |
| Address | 200 Great Pond Drive, PO Box 500<br>Windsor, CT 06095 |
| Telephone | 860-285-9986 |
| Email | james.bialobrzeski@ge.com |

# Table of Contents

# Section 1 – Boiler Upgrade Material

## 1.1 Radially Stratified Flame Core (RSFC™) Low NOx Gas Burners – Unit 1 Base Offer

The following is a listing of the major equipment and services included within the scope of the Company's Radially Stratified Flame Core (RSFC™) Low NOx Gas Burner replacement offer for the subject unit.

### 1.1.1 RSFC™ Burners

| Item | Quantity | Description |
|---|---|---|
| 1. | Sixteen (16) | RSFC™ gas burners rated for 70 MBtu/hr. gas maximum capacity, each register will be shop assembled, including shroud dampers, swirl & shroud linkage, scanner guide pipe, observation port, and ignitor guide pipe |
| 2. | Thirty-Two (32) | Manual inner and outer air swirl block damper drive mechanisms |
| 3. | Sixteen (16) | Electric damper drives with 4-20mA input positioner and 4-20mA feedback transmitter for the outer air dampers |
| 4. | Sixteen (16) | Electric damper drives with 4-20mA input positioner and 4-20mA feedback transmitter for the inner air dampers |
| 5. | Sixteen (16) | Fuel assemblies incorporating concentric gas gun assembly and core air pipe |
| 6. | Sixteen (16) | 12" core air supply pipes with butterfly valve |
| 7. | Sixteen (16) | Gas gun 4" "dog leg" stainless steel flex hose assemblies with piping, elbows, and flanges |
| 8. | Sixteen (16) | RSFC™ adapter flanges and mounting hardware to adapt new back panel to existing windbox |
| 9. | Sixteen (16) | Seal box modifications (*as required to accept the RSFC™ burner*) |
| 10. | As Required | Misc. A-36 burner support and windbox flow distribution steel |

### 1.1.2 Gas Pipe Ignitors

| Item | Quantity | Description |
|---|---|---|
| 11. | Sixteen (16) | LIMELIGHT™ 10 MBtu/hr 3" Class I bluff body gas pipe ignitors (to include gas gun, spark rod, IFM rod, bluff body eddy plate) |
| 12. | Sixteen (16) | LIMELIGHT™ gas ignitor control cabinets |
| 13. | Sixteen (16) | 1" stainless steel ignitor gas hoses |
| 14. | Sixteen (16) | Ignitor cooling air hoses |
| 15. | One (1) | Air system with two (2) 100% redundant fans rated for 8400 scfm for burner, ignitor and scanner air |

### 1.1.3 Exacta Flame Scanners

| Item | Quantity | Description |
|---|---|---|
| 16. | Sixteen (16) | LIMELIGHT™ Exacta VL flame scanners |
| 17. | Sixteen (16) | Scanner wire pigtails x 10 ft. long |
| 18. | Four (4) | NEMA 4 Flame Scanner cabinets with (2) frequency signal analyzer (FSA) modules with power supply |
| 19. | Sixteen (16) | Scanner cooling air hose with clamps |
| 20. | One (1) | PC Interface Software |

### 1.1.4 Separated Overfire Air (SOFA)

| Item | Quantity | Description |
|---|---|---|
| 21. | Four (4) | SOFA registers, located on the front wall above each burner column. Register equipped with required internal structural stiffeners and waterwall attachment flange. Each register is anticipated to have 2 compartments – internally linked |
| 22. | Eight (8) | SOFA air tips made from stainless steel, and associated linkage for tilt and yaw control |
| 23. | Four (4) | Electric tilt drives with 4-20mA input positioner and 4-20mA feedback transmitter for the outer air dampers |
| 24. | Eight (8) | Electric damper drives with 4-20mA input positioner and 4-20mA feedback transmitter for the outer air dampers |
| 25. | Four (4) | Waterwall offset tube panels to allow for new SOFA opening |

| | | |
|---|---|---|
| 26. | Four (4) | Seal boxes, for new offset tubes and compartments integrated into the tube panel during manufacturing |
| 27. | As Required | Ductwork, including stiffeners, hanger support system, expansion joints and all hardware necessary to install. |

### 1.1.5 Main Gas Header Components

| Item | Quantity | Description |
|---|---|---|
| 28. | One (1) | Main Gas and Ignitor Header Isolation Valve |
| 29. | One (1) | Gas Supply Header Flow meter |
| 30. | One (1) | Main Gas Header Pressure Transmitter with manual Isolation Valves |
| 31. | Two (2) | Gas Supply Header Pressure Indicator gauge and manual isolation valve |
| 32. | One (1) | Main Gas Header Safety shutoff valve with pneumatic actuator, pilot solenoid valve and open closed end limit switches |
| 33. | One (1) | Main Gas Control Valve with Pneumatic Actuator and Positioner |
| 34. | One (1) | Main Gas Minimum Bypass Regulating Valve |
| 35. | Three (3) | Main Gas Header Pressure Transmitters with manual Isolation Valves |
| 36. | One (1) | Main Gas Header Vent Valve with pneumatic actuator, pilot solenoid valve and open / closed end limit switches |
| 37. | One (1) | Valve Skid for Main Gas header and Ignitor Gas Header Valves |

### 1.1.6 Ignitor Gas Header Components

| Item | Quantity | Description |
|---|---|---|
| 38. | One (1) | Ignitor Gas Header Low Pressure Switch |
| 39. | One (1) | Ignitor Gas Header Pressure Indicator |
| 40. | One (1) | Ignitor Gas Header Safety shutoff valve with pneumatic actuator, pilot solenoid valve and open closed end limit switches |
| 41. | One (1) | Ignitor Gas Header Control Valve with Pneumatic Actuator and Positioner |
| 42. | Three (3) | Ignitor Gas Header Pressure Transmitters with manual Isolation valves |
| 43. | One (1) | Ignitor Gas Header Pressure Indicator gauge and manual isolation valve |

| | | |
|---|---|---|
| 44. | One (1) | Ignitor Gas Header Vent Valve with pneumatic actuator, pilot solenoid valve and open / closed end limit switches |

### 1.1.7 Burner Gas Components

| Item | Quantity | Description |
|---|---|---|
| 45. | Sixteen (16) | Main Gas Burner Shutoff Valves (manual) |
| 46. | Thirty-Two (32) | Main Gas Burner Safety Shutoff Valves with pneumatic actuator, pilot solenoid valve and open / closed end limit |
| 47. | Sixteen (16) | Main Gas Burner Vent Valves with pneumatic actuator, pilot solenoid valve and open / closed end limit switches |
| 48. | Sixteen (16) | Main Gas Burner Pressure Indicator |

### 1.1.8 Ignitor Gas Components

| Item | Quantity | Description |
|---|---|---|
| 49. | Sixteen (16) | Ignitor Gas Shutoff Valves (manual) |
| 50. | Sixteen (16) | Ignitor Gas Strainer |
| 51. | Thirty-Two (32) | Ignitor Gas Safety Shutoff Valves with pneumatic actuator, pilot solenoid valve and open / closed end limit switches |
| 52. | Sixteen (16) | Ignitor Gas Vent Valves with pneumatic actuator, pilot solenoid valve and open / closed end limit switches |
| 53. | Sixteen (16) | Ignitor Gas Flow Control Valve (manual) |

## 1.2 Natural Gas Conversion – Unit 2 Option 1

The following is a listing of the major equipment and services included within the scope of the Company's Natural Gas Conversion equipment offer for the subject unit.

### 1.2.1 Main Windbox Components

| Item | Quantity | Description |
|---|---|---|
| 1. | Twenty-Four (24) | One-piece, tilting gas nozzle tips fabricated from 309 stainless steel. |
| 2. | Twelve (12) | Gas compartment assemblies with two (2) gas spuds and one (1) manifold assembly. |
| 3. | Twenty-Eight (28) | One-piece air nozzle tips fabricated from 309 stainless steel. |
| 4. | Twelve (12) | Gas flex hose "dog leg" assemblies |

### 1.2.2 Gas Side Ignitors

| Item | Quantity | Description |
|---|---|---|
| 5. | Twelve (12) | LIMELIGHT™ 6 MBtu/hr 3" gas side ignitors (to include gas gun, spark rod, IFM rod and mounting panel |
| 6. | Twelve (12) | LIMELIGHT™ gas ignitor control cabinets |
| 7. | Twelve (12) | 1" stainless steel ignitor gas hoses |
| 8. | Twelve (12) | Ignitor cooling air hoses |

### 1.2.3 Exacta Flame Scanners

| Item | Quantity | Description |
|---|---|---|
| 9. | Twelve (12) | LIMELIGHT™ Exacta VL flame scanners |
| 10. | Twelve (12) | Scanner wire pigtails x 10 ft. long |
| 11. | Three (3) | NEMA 4 Flame Scanner cabinets with (2) frequency signal analyzer (FSA) modules with power supply |
| 12. | Twelve (12) | Scanner cooling air hose with clamps |
| 13. | One (1) | PC Interface Software |

### 1.2.4 Main Gas Header Components

| Item | Quantity | Description |
|---|---|---|
| 14. | One (1) | Main Gas and Ignitor Header Isolation Valve |
| 15. | One (1) | Gas Supply Header Flow meter |
| 16. | One (1) | Main Gas Header Pressure Transmitter with manual Isolation Valves |
| 17. | Two (2) | Gas Supply Header Pressure Indicator gauge and manual isolation valve |
| 18. | One (1) | Main Gas Header Safety shutoff valve with pneumatic actuator, pilot solenoid valve and open closed end limit switches |
| 19. | One (1) | Main Gas Control Valve with Pneumatic Actuator and Positioner |
| 20. | One (1) | Main Gas Minimum Bypass Regulating Valve |
| 21. | Three (3) | Main Gas Header Pressure Transmitters with manual Isolation Valves |
| 22. | One (1) | Main Gas Header Vent Valve with pneumatic actuator, pilot solenoid valve and open / closed end limit switches |
| 23. | One (1) | Valve Skid for Main Gas header and Ignitor Gas Header Valves |

### 1.2.5 Ignitor Gas Header Components

| Item | Quantity | Description |
|---|---|---|
| 24. | One (1) | Ignitor Gas Header Low Pressure Switch |
| 25. | One (1) | Ignitor Gas Header Pressure Indicator |
| 26. | One (1) | Ignitor Gas Header Safety shutoff valve with pneumatic actuator, pilot solenoid valve and open closed end limit switches |
| 27. | One (1) | Ignitor Gas Header Control Valve with Pneumatic Actuator and Positioner |
| 28. | Three (3) | Ignitor Gas Header Pressure Transmitters with manual Isolation valves |
| 29. | One (1) | Ignitor Gas Header Pressure Indicator gauge and manual isolation valve |
| 30. | One (1) | Ignitor Gas Header Vent Valve with pneumatic actuator, pilot solenoid valve and open / closed end limit switches |

### 1.2.6 Burner Gas Components

| Item | Quantity | Description |
|---|---|---|
| 31. | Twelve (12) | Main Gas Burner Shutoff Valves (manual) |
| 32. | Twenty-Four (24) | Main Gas Burner Safety Shutoff Valves with pneumatic actuator, pilot solenoid valve and open / closed end limit |
| 33. | Twelve (12) | Main Gas Burner Vent Valves with pneumatic actuator, pilot solenoid valve and open / closed end limit switches |
| 34. | Twelve (12) | Main Gas Burner Pressure Indicator |

### 1.2.7 Ignitor Gas Components

| Item | Quantity | Description |
|---|---|---|
| 35. | Twelve (12) | Ignitor Gas Shutoff Valves (manual) |
| 36. | Twelve (12) | Ignitor Gas Strainer |
| 37. | Twenty-Four (24) | Ignitor Gas Safety Shutoff Valves with pneumatic actuator, pilot solenoid valve and open / closed end limit switches |
| 38. | Twelve (12) | Ignitor Gas Vent Valves with pneumatic actuator, pilot solenoid valve and open / closed end limit switches |
| 39. | Twelve (12) | Ignitor Gas Flow Control Valve (manual) |

## 1.3 Natural Gas Conversion – Unit 3 Option 2

The following is a listing of the major equipment and services included within the scope of the Company's Natural Gas Conversion equipment offer for the subject unit.

### 1.3.1 Main Windbox Components

| Item | Quantity | Description |
|---|---|---|
| 1. | Thirty-Two (32) | One-piece, tilting gas nozzle tips fabricated from 309 stainless steel. |
| 2. | Sixteen (16) | Gas compartment assemblies with two (2) gas spuds and one (1) manifold assembly. |
| 3. | Forty (40) | One-piece air nozzle tips fabricated from 309 stainless steel. |
| 4. | Sixteen (16) | Gas flex hose "dog leg" assemblies |

### 1.3.2 Gas Side Ignitors

| Item | Quantity | Description |
|---|---|---|
| 5. | Sixteen (16) | LIMELIGHT™ 6 MBtu/hr 3" gas side ignitors (to include gas gun, spark rod, IFM rod and mounting panel |
| 6. | Sixteen (16) | LIMELIGHT™ gas ignitor control cabinets |
| 7. | Sixteen (16) | 1" stainless steel ignitor gas hoses |
| 8. | Sixteen (16) | Ignitor cooling air hoses |

### 1.3.3 Exacta Flame Scanners

| Item | Quantity | Description |
|---|---|---|
| 9. | Sixteen (16) | LIMELIGHT™ Exacta VL flame scanners |
| 10. | Sixteen (16) | Scanner wire pigtails x 10 ft. long |
| 11. | Four (4) | NEMA 4 Flame Scanner cabinets with (2) frequency signal analyzer (FSA) modules with power supply |
| 12. | Sixteen (16) | Scanner cooling air hose with clamps |
| 13. | One (1) | PC Interface Software |

### 1.3.4 Main Gas Header Components

| Item | Quantity | Description |
|---|---|---|
| 14. | One (1) | Main Gas and Ignitor Header Isolation Valve |
| 15. | One (1) | Gas Supply Header Flow meter |
| 16. | One (1) | Main Gas Header Pressure Transmitter with manual Isolation Valves |
| 17. | Two (2) | Gas Supply Header Pressure Indicator gauge and manual isolation valve |
| 18. | One (1) | Main Gas Header Safety shutoff valve with pneumatic actuator, pilot solenoid valve and open closed end limit switches |
| 19. | One (1) | Main Gas Control Valve with Pneumatic Actuator and Positioner |
| 20. | One (1) | Main Gas Minimum Bypass Regulating Valve |
| 21. | Three (3) | Main Gas Header Pressure Transmitters with manual Isolation Valves |
| 22. | One (1) | Main Gas Header Vent Valve with pneumatic actuator, pilot solenoid valve and open / closed end limit switches |
| 23. | One (1) | Valve Skid for Main Gas header and Ignitor Gas Header Valves |

### 1.3.5 Ignitor Gas Header Components

| Item | Quantity | Description |
|---|---|---|
| 24. | One (1) | Ignitor Gas Header Low Pressure Switch |
| 25. | One (1) | Ignitor Gas Header Pressure Indicator |
| 26. | One (1) | Ignitor Gas Header Safety shutoff valve with pneumatic actuator, pilot solenoid valve and open closed end limit switches |
| 27. | One (1) | Ignitor Gas Header Control Valve with Pneumatic Actuator and Positioner |
| 28. | Three (3) | Ignitor Gas Header Pressure Transmitters with manual Isolation valves |
| 29. | One (1) | Ignitor Gas Header Pressure Indicator gauge and manual isolation valve |
| 30. | One (1) | Ignitor Gas Header Vent Valve with pneumatic actuator, pilot solenoid valve and open / closed end limit switches |

### 1.3.6 Burner Gas Components

| Item | Quantity | Description |
|---|---|---|
| 31. | Sixteen (16) | Main Gas Burner Shutoff Valves (manual) |
| 32. | Thirty-Two (32) | Main Gas Burner Safety Shutoff Valves with pneumatic actuator, pilot solenoid valve and open / closed end limit |
| 33. | Sixteen (16) | Main Gas Burner Vent Valves with pneumatic actuator, pilot solenoid valve and open / closed end limit switches |
| 34. | Sixteen (16) | Main Gas Burner Pressure Indicator |

### 1.3.7 Ignitor Gas Components

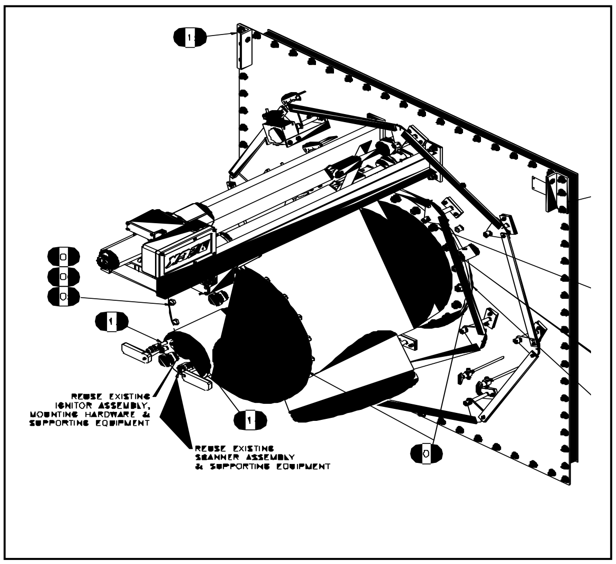
| Item | Quantity | Description |
|---|---|---|
| 35. | Sixteen (16) | Ignitor Gas Shutoff Valves (manual) |
| 36. | Sixteen (16) | Ignitor Gas Strainer |
| 37. | Thirty-Two (32) | Ignitor Gas Safety Shutoff Valves with pneumatic actuator, pilot solenoid valve and open / closed end limit switches |
| 38. | Sixteen (16) | Ignitor Gas Vent Valves with pneumatic actuator, pilot solenoid valve and open / closed end limit switches |
| 39. | Sixteen (16) | Ignitor Gas Flow Control Valve (manual) |

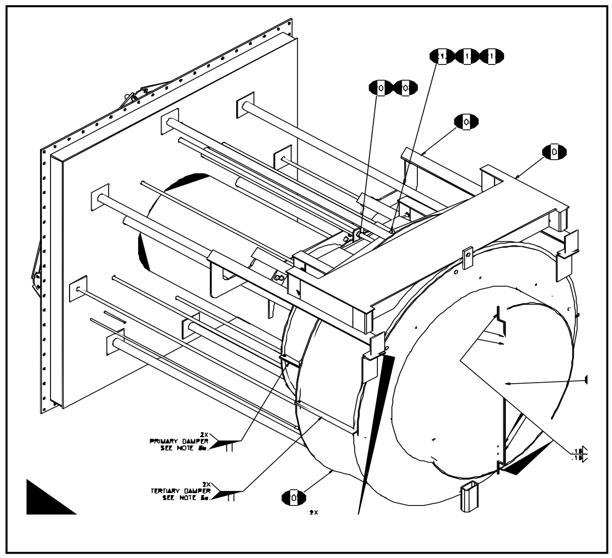
# Section 2 – Technical Description

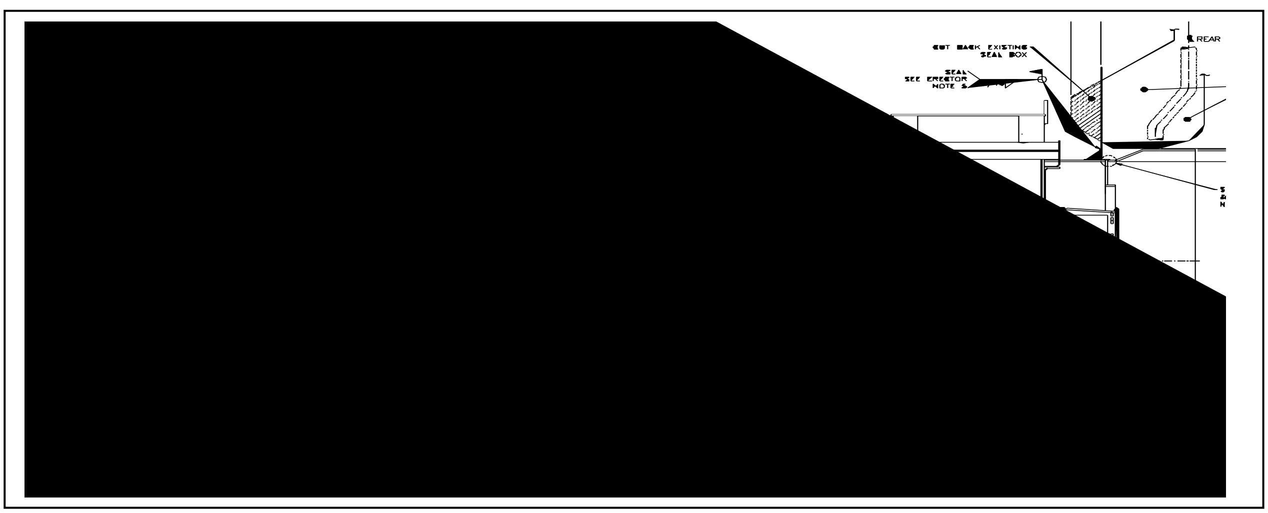
## 2.1 Radially Stratified Flame Core (RSFC™) Low NOx Gas Burners – Unit 1 Base Offer

Unit 1 is a 114 MW (gross) rated Babcock & Wilcox front wall fired, split furnace, pulverized coal boiler that houses sixteen (16) coal burners, four (4) levels of four (4) burners per level, commissioned in 1957. The unit utilizes No. 2 fuel oil for igniters/warm-up. The unit design conditions are indicated in Table 6 of B&V bid specification. Particulate emissions are controlled by an electro-static precipitator (ESP), and share a flue gas desulphurization (FGD) system and a stack with Units 2 and 3. The unit does not have a selective catalytic reduction (SCR) system

The Company proposes to supply sixteen (16) RSFC™ coal and gas burners. Each burner will be sized for 90 MBtu/hr firing coal assuming one (1) mill out of service and 70 MBtu/hr firing gas with all burners in service. Each burner will include two (2) view ports and one (1) scanner mount. The outer (tertiary) and inner (primary) air dampers will be automated with linear electric drives. Separated Overfire Air (SOFA) register have been included. There will be four (4) SOFA windboxes, coming off the top of the main windbox above each burner column row. Each SOFA register will have two (2) nozzle tips, one (1) tilt drive and two (2) damper drives.

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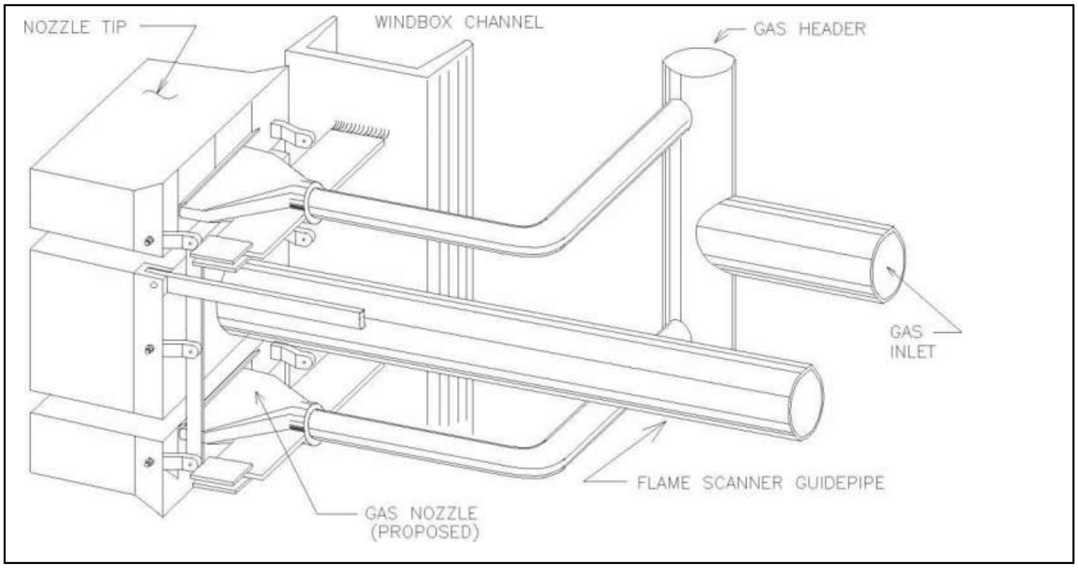
## 2.2 Natural Gas Conversion – Unit 2 Option 1

Unit 2 is a 180 MW (gross) rated Combustion Engineering tangential-fired, single furnace, pulverized coal boiler that houses sixteen (16) coal burners, commissioned in 1963. The unit utilizes No. 2 fuel oil for igniters/warm-up. The unit design conditions are indicated in Table 6 of B&V bid specification. Particulate emissions are controlled by an electro-static precipitator (ESP), and share a flue gas desulphurization (FGD) system and a stack with Units 1 and 3. The unit does not have a selective catalytic reduction (SCR) system.

The Company proposes to supply three (3) elevations of gas guns for the intermediate auxiliary air compartments between the bottom three (3) coal elevations and in the lower CCOFA compartment. Each compartment will have new nozzle tips, gas gun, side ignitor, and flame scanner. The CCOFA compartment will be a three (3) tip design and the intermediate auxiliary compart will be a five (5) tip design. The gas guns will be sized for 140 MBtu/hr and the side ignitors rated for 6 MBtu/hr. The ignitor air system will be reused. The mounting box and offset tube for the side ignitors for coal elevations 3 & 4 will be relocated to the new gas elevations and replaced with gas side ignitors.




## 2.3 Natural Gas Conversion – Unit 3 Option 2

Unit 3 is a 457 MW (gross) rated Combustion Engineering tangential-fired, single furnace, pulverized coal boiler that houses twenty (20) coal burners, commissioned in 1971. The unit utilizes No. 2 fuel oil for igniters/warm-up. The unit design conditions are indicated in Table 6 of B&V bid specification. NOx emissions are controlled by a selective catalytic reduction (SCR) system. Particulate emissions are controlled by a bag house, and share a flue gas desulphurization (FGD) system and a stack with Units 1 and 2.

The Company proposes to supply four (4) elevations of gas guns for the intermediate auxiliary air compartments between the bottom four (4) coal elevations and in the lower CCOFA compartment. Each compartment will have new nozzle tips, gas gun, side ignitor, and flame scanner. The CCOFA compartment will be a three (3) tip design and the intermediate auxiliary compart will be a five (5) tip design. The gas guns will be sized for 270 MBtu/hr and the side ignitors rated for 10 MBtu/hr. The ignitor air system will be reused. The mounting box and offset tube for the side ignitors for coal elevations 3 & 4 will be relocated to the new gas elevations and replaced with gas side ignitors.

## 2.4 Work Not Included

This proposal does not include the following work which is assumed to be completed by others:

- Gas Conversion Study (This could be proposed which would result in additional thermal performance predictions)
- Installation
- Technical Services Supervision
- Baseline or Performance Guarantee Testing
- Electrical engineering (power distribution, one line drawings, raceway routing , etc.)
- Detailed gas, instrument air and vent piping drawings (suggested gas routing diagrams only)
- Existing steel modifications
- Platform modifications
- Gas piping
- Coal piping
- Gas piping hanger or support steel
- Any gas high pressure reducing station (600 psig to 50 – 75 psig)
- Corner valve skids
- Vent piping, piping hangers or support steel
- Air flow monitoring equipment
- CFD Modeling
- Implementation of the controls logic that would be forwarded as part of a materials purchase

## 2.5 Field Service Support

It is recommended that the above modifications (installation, set-up and initial start-up) be supervised by the Company's representative to ensure a successful and trouble free retrofit.

The Company can provide a Service Engineer (SE) to offer field technical support to the Purchaser as requested during the project. The SE can perform an array of activities prior to, during and following the outage, as an advisor to the Purchaser. These services can be provided on a per diem basis, at the rate prevailing at the time of service, as requested by the Purchaser.

As a basis for an estimate price the Company would need an outage duration, the number of shifts worked per and the amount of days per week.

**Table 2 General Proposal Fill-In Data**

| | UNIT 1 | UNIT 2 | UNIT 3 |
|---|---|---|---|
| | **100% MCR** | **100% MCR** | **100% MCR** |
| Low NOx Burners | | | |
| New Burners (number) | 16 | 12 | 16 |
| | | | |
| Overfire Air System. (if applicable) | | | |
| Number of ports | 4 | N/A | N/A |
| | | | |
| Igniter Equipment | | | |
| Number provided | 16 | 12 | 16 |
| Type | Gas pipe | Gas side | Gas side |
| Rated Capacity, MBtu/hr | 10 | 6 | 10 |
| | | | |
| Flame Scanner Equipment | | | |
| Number provided | 16 | 12 | 16 |
| Type | Visible light | Visible light | Visible light |

**Table 3 General Proposal Fill-In Data – Predicted Emissions**

| (PREDICTED AT THE AIR HEATER OUTLET) | UNIT 1 | UNIT 2 | UNIT 3 |
|---|---|---|---|
| Burners Only | | | |
| NOx, lb/MBtu | 0.15 – 0.20 | N/A | N/A |
| CO, lb/MBtu | <0.15 | N/A | N/A |
| Burners + SOFA | | | |
| NOx, lb/MBtu | 0.12 – 0.17 | <0.10 | <0.10 |
| CO, lb/MBtu | <0.15 | <0.15 | <0.15 |

**Table 4 Scope of Supply**

| | INCLUDED YES OR NO |
|---|---|
| CFD Modeling | No |
| Burner Replacement | Yes |
| Secondary air modifications | Yes |
| Igniters | Yes |
| Scanners | Yes |
| SOFA System | Unit 1 only |
| FGR System | No |
| Logic diagrams | Yes, Contract phase |
| I/O List | Yes, Contract phase |
| System Operating Description | Yes, Contract phase |
| Pressure Reducing and Metering Skids (3) | No, (1) Main Gas & Ignitor Gas Skid per unit |
| Burner Control Piping Skids (3) | No, loose |
| Field Service Included | No, need outage length |
| Number of man days | N/A |
| Number of round trips | N/A |

# Section 4 – Commercial

## 4.1 Budget Pricing

GE is pleased to provide the work and material in accordance with this proposal, Sections 1, 2, and 3 above, as follows:

The Budget Material Price for the Company's Gas Conversion Material on Unit 1, as described in this Proposal, is:

**Four Million Three Hundred Seventy-Five Thousand Dollars**
**($4,375,000.00)**

The Budget Material Price for the Company's Gas Conversion Material on Unit 2, as described in this Proposal, is:

**One Million Five Hundred Twenty-Five Thousand Dollars**
**($1,525,000.00)**

The Budget Material Price for the Company's Gas Conversion Material on Unit 3, as described in this Proposal, is:

**One Million Eight Hundred Twenty-Five Thousand Dollars**
**($1,825,000.00)**

## 4.2 Pricing Basis

GE's prices do not include any taxes other than employment taxes. Purchaser will pay all sales, use, value added, excise, and other taxes, which may be levied or assessed in connection with this proposal or GE's performance under the proposal. To the extent GE is required to pay any such taxes, Purchaser will reimburse GE promptly upon receipt of an invoice. If applicable, Purchaser will also please provide GE with any exemption certificates, direct pay permits and/or other relevant documents in sufficient time to claim any tax exemption on this transaction.

Note that GE's pricing does not account for costs associated with bonds, letters of credit, or any other security instruments. To the extent GE is required by the Purchaser to secure any such instrument(s), the contract price will be adjusted accordingly.

The availability of GE facilities, equipment, and stock items are subject to prior sale.

## 4.3 Schedule

Based upon current engineering and production schedules, the Company anticipates that the material and/or equipment described in this Proposal could be shipped to be at the jobsite approximately Forty to Forty-Two (40 - 42) weeks after its receipt of an acceptable purchase order.

This lead-time does not include actual shipping time from the manufacturing point to the specified destination, nor additional time which may be required for approval of drawings, plans, and specifications by the Purchaser.

## 4.4 Shipment

The material and equipment described in this proposal are quoted Delivered At Place (DAP) Harrodsburg, KY Incoterms 2010.

# CONFIDENTIAL CLIENT
## BOILERS 1, 2 & 3

## NATURAL GAS CONVERSION WITH OPTION OF OVER-FIRE AIR & INDUCED FLUE GAS RECIRCULATION

**PROPOSAL**

**FOR**

**BLACK & VEATCH CORPORATION**
**Kansas City, Missouri**

Proposal No. P-16-400-P1
December 28, 2016

Prepared by:

Peter D. Marx, P.E.
Step Combustion
5 Turnberry Lane
Sandy Hook, CT 06482
(603) 845-6405

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## 1.0 EXECUTIVE SUMMARY

Step Combustion (STEP) proposes to add natural firing on Boilers 1, 2 & 3. The boilers are described as follows:

Unit 1 is a 114 MW (gross) rated Babcock & Wilcox front wall fired, split furnace, pulverized coal boiler that houses sixteen (16) coal burners, four levels of four burners per level, commissioned in 1957. The unit utilizes No. 2 fuel oil for igniters/warm-up. Particulate emissions are controlled by an electro-static precipitator (ESP), and share a flue gas desulphurization (FGD) system and a stack with Units 2 and 3. The unit does not have a selective catalytic reduction (SCR) system.

Unit 2 is a 180 MW (gross) rated Combustion Engineering tangential-fired, single furnace, pulverized coal boiler that houses sixteen (16) coal burners, commissioned in 1963. The unit utilizes No. 2 fuel oil for igniters/warm-up. Particulate emissions are controlled by an electro-static precipitator (ESP), and share a flue gas desulphurization (FGD) system and a stack with Units 1 and 3. The unit does not have a selective catalytic reduction (SCR) system.

Unit 3 is a 457 MW (gross) rated Combustion Engineering tangential-fired, single furnace, pulverized coal boiler that houses twenty (20) coal burners, commissioned in 1971. The unit utilizes No. 2 fuel oil for igniters/warm-up. NOx emissions are controlled by a selective catalytic reduction (SCR) system. Particulate emissions are controlled by a bag house, and share a flue gas desulphurization (FGD) system and a stack with Units 1 and 2.

Table 1 also illustrates the major components on each of the boilers.

**Table 1**
**Major Boiler Components**

| Components | Unit 1 | Unit 2 | Unit 3 |
|---|---|---|---|
| Number of Burners | 16 | 16 | 20 |
| Number of OFA Ports | 0 | 2 | 4 |
| Number of FD Fans | 2 | 2 | 2 |
| Number of ID Fans | 1 (single speed) | 2 (two speed) | 2 (two speed) |
| Precipitator | 1 | 2 Box | Bag House |
| SCR | No | No | Yes |
| FGD | Shared | Shared | Shared |
| Stack | One (1) Shared | One (1) Shared | One (1) Shared |

Natural gas firing presents three methods for NOx reduction and optimum combustion.

- The existing coal fired burners will be upgraded with Ultra Low NOx natural gas burners.
- Adding Four (4) Over Fire Air (OFA) ports above the firing elevation on each of the boiler.
- Adding Flue Gas Recirculation (FGR) to the combustion air.

Based on the burner zone heat release and boiler type Table 2 is the estimated NOx emissions for each of the technologies.

**Table 2**
**Estimated Emissions for Units 1, 2 & 3**

| **Predicted at the Air Heater Outlet** | **Unit 1** | **Unit 2** | **Unit 3** |
|---|---|---|---|
| **Burners Only** | | | |
| NOx, lb/mmBtu | 0.20 | 0.20 | 0.20 |
| CO, lb/mmBtu | 0.15 | 0.15 | 0.15 |
| **Burners + OFA** | | | |
| NOx, lb/mmBtu | 0.15 | 0.15 | 0.15 |
| CO, lb/mmBtu | 0.15 | 0.15 | 0.15 |
| **Burners + FGR** | | | |
| NOx, lb/mmBtu | 0.13 | 0.13 | 0.13 |
| CO, lb/mmBtu | 0.15 | 0.15 | 0.15 |
| **Burners + OFA + FGR** | | | |
| NOx, lb/mmBtu | 0.10 | 0.10 | 0.10 |
| CO, lb/mmBtu | 0.15 | 0.15 | 0.15 |

Main fuel and igniter fuel valve trains will be included to meet current NFPA recommendations. A description of the supplied components is included below.

## 2.0 PRICING

Listed in Table 3 is the pricing for the proposed Ultra Low NOx burners, Gas Trains, OFA System, FGR System, Igniters and Scanners. A description of each aspect is detailed below.

**Table 3**
**Project Pricing for Boilers 1, 2 & 3**

| **Natural Gas** | **Unit 1** | **Unit 2** | **Unit 3** |
|---|---|---|---|
| Project Management / Engineering | $80,000 | $50,000 | $90,000 |
| Replacement Burners | $600,000 | $360,000 | $450,000 |
| Igniters | $152,000 | $139,200 | $174,000 |
| Flame Scanners | $120,000 | $120,000 | $150,000 |
| OFA System | $150,000 | $187,000 | $197,000 |
| Fuel Supply System Modifications | $280,000 | $280,000 | $360,000 |
| Flue Gas Recirculation System (Fan Assisted) | $255,000 | $265,000 | $350,000 |
| Freight, FOB Factory | $7,500 | $7,500 | $10,000 |
| Boiler Total | $1,644,500 | $1,408,700 | $1,781,000 |

* - IFGR would reduce the cost by approximately $110,000 per boiler

All prices are quoted exclusive of state and local sales, excise, use or any other taxes. Such taxes, if applicable, will be in addition to the above prices and will be charged to your account. Any taxes assessed to STEP at a later date will be charged to your account. If the above items are tax-exempt, the applicable tax exemption certificate is to be sent to STEP with your purchase order.

## 3.0 DETAILED DESCRIPTION

Step Combustion will provide a combustion optimization program that will include the supply new burners and addition of OFA or IFGR. Table 4 is a summary of the program provided with a detailed description detailed below.

**Table 4**
**Boilers 1, 2 & 3**
**Low NOx Program**

| Parameter | Included Yes or No |
|---|---|
| CFD Modeling | Yes |
| Burner Replacement | Yes |
| Secondary Air Modifications | Yes |
| Igniters | Yes |
| Scanners | Yes |
| SOFA System | Yes |
| FGR System | Yes |
| CCS / BMS Operating Description | Yes |
| I/O List | Yes |
| System Operating Description | Yes |
| Pressure Reducing and Metering Skids (3) | Yes |
| Burner Control Piping Skids (3) | Yes |
| Field Service Included | Yes |
| Number of man days | 30 |
| Number of round trips | 8 |

- Engineering evaluation of the existing combustion system. This will include a site visit to assess the performance of the system, verify system drawings and perform initial component design.

- Computational Fluid Dynamics (CFD) modeling will be performed of the proposed Low NOx burner design and implementation into the existing boilers. This will be utilized to determine the optimum gas poker injection pattern to optimize Low NOx combustion. Figure 1 is an illustration of the burner combustion aspects integrated into the entire furnace. Model outputs will include, temperature, heat flue, species (O2, Co, NOx, etc.) distributions, and velocities in the furnace and at the model outlet (Typically the furnace outlet)

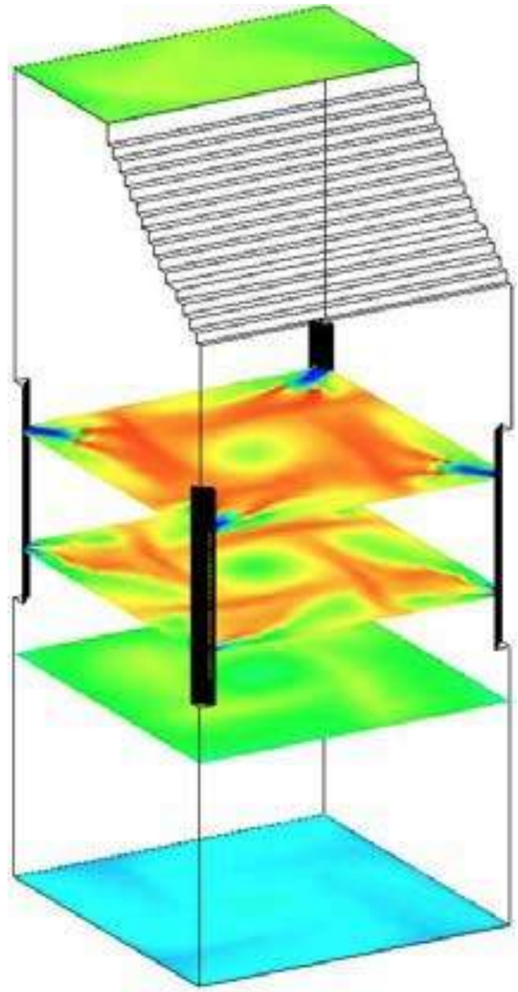


**Figure 1**
**CFD Model Flow Stream**

- A detailed report of the CFD model results will include:
  - Flame shape
  - Peak Flame Temperatures
  - Emission Rates
  - Stability Analysis
  - Impact of Burner Adjustments

- Design of new burners with detailed drawings provided for review and comment.
- Provide CCS and BMS control description for implementation into the existing systems

- Fabrication and Shipment of Hardware

- Installation plan with drawings and description to support the removal of the existing combustion hardware and installation of the new hardware. A STEP engineer will be on site for up to ten (10) days per boiler to provide installation technical support.

- Start up and operation optimization support that includes a STEP engineer for up to five days per boiler.

## 3.1 Low NOx Burners

Each boiler will be upgraded with LNB as described below.

### 3.1.1 Wall Fired Burners

Unit 1 single wall fired burner will be replaced with STEP's Ultra Low NOx Variswirl Design. Variswirl design utilizes a venturi style air register with Low NOx Swirler and Gas pokers to reduce NOx formation with optimized combustion. Listed below are the design attributes of the Variswirl burner.

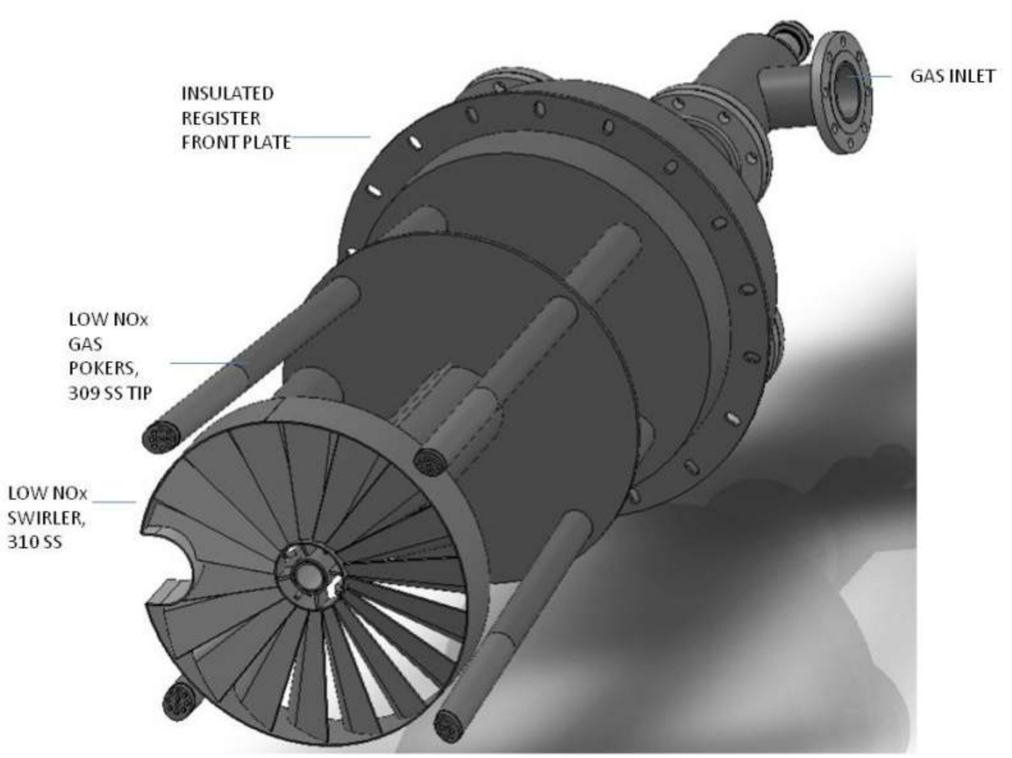



**Figure 2**
**Variswirl Burner**

- Venturi combustion air register to ensure balanced flow around the burner perimeter
- Low NOx Swirler fabricated from 310 SS for high temperature operation.

- 309 SS Fuel Rich and Lean Gas that develop stage combustion for Low NOx operation
- Automated zone disk with Jordan drive to control airflow to each burner over the load range.
- Insulated burner front plate that matches the existing windbox bolt pattern for ease of installation.
- Center gas supply to pokers that will match up with the current fuel supply inlet pipe flange.

As shown in Figure 3 the poker size and orientation change around the circumference. A large volume of gas is injected through four (4) of the pokers and approximately 10% through a set of pokers through the swirler hub. This creates rich and lean zones of combustion at the burner outlet to reduce NOx formation. The igniter will be positioned adjacent to a set of pokers to initiate combustion of the main burner.

**Figure 3**
**Furnace Side View**

Scope of Hardware Supply for the Variswirl burner is as follows: (All Material Carbon Steel unless noted)

- Insulated Burner Front Plate with matching connection flange, site ports, igniter port and zone disk drive support
- Carbon Steel Venturi Air Register with internal windbox support structure.
- Center Gas Header with inlet flange
- Gas Plenum with Pokers extending to the furnace side edge of burner throat
- Pokers can be rotated and removed from the burner front
- Fuel Rich 309 SS Gas Pokers
- 310 SS Low NOx Swirler

### 3.1.2 Tangential Fired Boiler LNB

Boilers 2 and 3 are Tangential boilers with four (4) and five (5) elevation of corner fired burners. Coal firing will be removed and gas burners installed in the fuel air buckets. STEP's T-Fired Design injects gas in two (2) zones within the fuel air bucket. This creates a split flame at the burner exit to reduce peak flame temperature and thermal NOx formation. Figure 4 illustrates the addition of gas firing within tangential fired burner fuel air bucket.

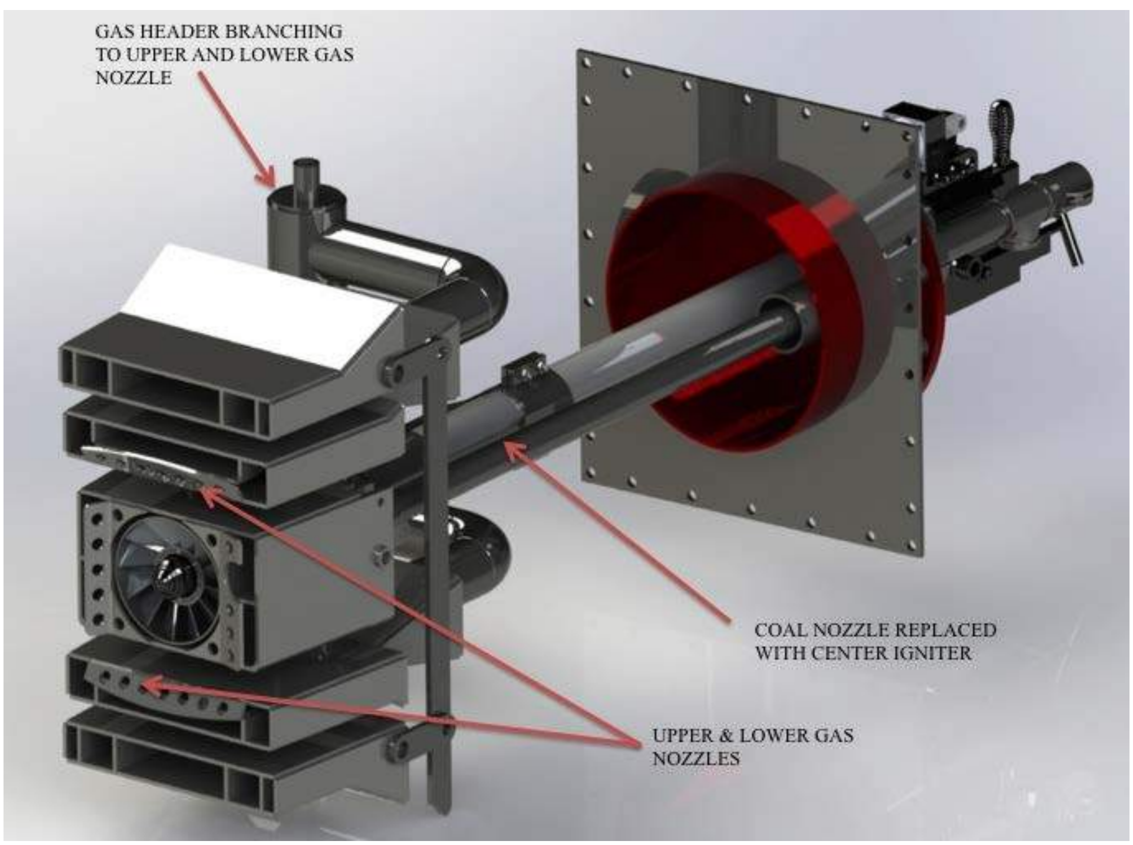



**Figure 4**
**T-Fired Burner**

A single gas line from the burner front, feeds a vertical header within the corner windbox. Two (2) gas branches extend from the vertical header to the smaller fuel air bucket above and below the center fuel bucket. The coal nozzle is replaced with a natural igniter assembly and secondary air swirler. Another view of the gas implantation within the burner is shown in Figure 5.

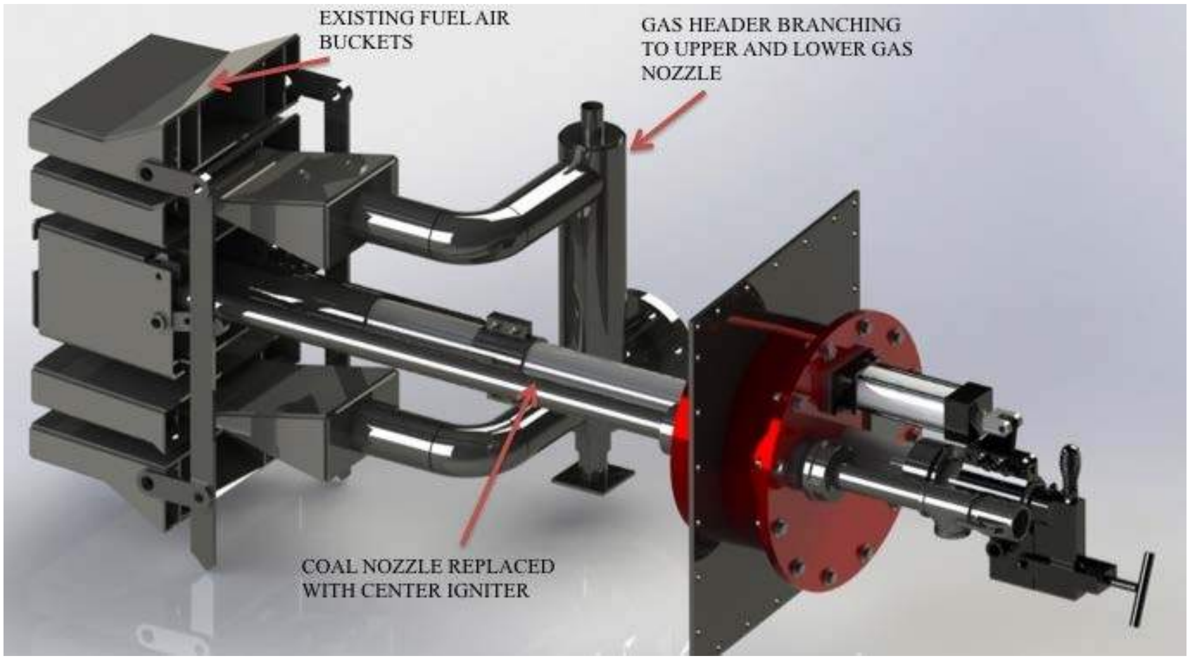



**Figure 5**
**T-Fired Burner Windbox View**

Attributes of the burner upgrade is as follows with all components carbon steel unless noted:

- Main gas pipe and flex hose
- Vertical gas header
- Branch line and 310 SS gas injection nozzles
- Secondary air center diffuser

### 3.2 Forney Max Fire Igniters & Igniter Safety Shut Off Assembly

All the burners for Boilers 1, 2, and 3 will have new Forney Max Fire 30 natural gas Class I igniters. The Igniter will be capable of providing 10% of full load heat input on a continuous basis. The hardware associated with the new igniter is as follows:

- Igniter assembly
- Igniter Mounting Tube
- Spark Rod with High Energy Spark Igniter (HESI) Transformer
- Stainless Steel flex hose

- Cooling Air Hose

The igniter will require 15 scfm of cooling / combustion airflow at 6” Wc above full load furnace pressure.

Igniter operation will be controlled with a safety shutoff skid that meets the current NFPA recommendations. Components of the safety shut off and vent assembly consists of the following:

- 2” Manual isolation valve
- Pressure regulator
- Block valves each 2” ball, fire safe with pneumatic actuator fail closed on loss of power or air, single coil solenoid. Includes 2 SPDT open/closed limit switches.
- Vent Valve, 1” ball, fire safe, with pneumatic actuator fail opened on loss of power or air, single coil. Includes 2 SPDT open/closed limit switches.
- 2” Y-Strainer (40 mesh)
- Pressure Gauge with Manual isolation valve

  All components will be a pipe assembled and wired to a NEMA 4X enclosure for field connection.

### 3.3 Forney Flame Scanners

All the burners for Boilers 1, 2, and 3 will have two (2) new UV UNIFlame II Detectors: Expanded with all electronics mounted in the flame detector head providing the following functions directly from the detector head via prefab cable connector:

Flame detected
Flame detector self-check fault
4-20 ma flame intensity signal
Flame signature selection
RS485 communication

Each Consisting of:

- Uniflame II expanded integrated UV sensor flame scanner head and amplifier unit for main flame detection.
- Mounting hardware including
  - 1” nipple
  - 1” cooling air wye with swivel mount
  - Cable, 40 ft, 12-conductor prefabricated with prefabricated connector on one end and loose wires on the other end.

### 3.4 Main Gas Regulating and Control Skids

Boilers 1, 2 & 3 will each have a new gas regulating and control skids. To meet NFPA recommendations will have a main pressure-regulating skid with flow control on a boiler basis. In addition each burner will have an associated main burner valve train to ensure safe start up, shut down and burner venting.

- Burner gas supply header train with manual shut off valves, Flow Control Valves, Flow Meter, High and Low Pressure Switches, Pressure Gauges, Pneumatic Block Valves, Interconnection piping and fittings. 3000# socket or butt weld fittings to be used as appropriate. All train boundaries will be 150# raised face flanges.

- Burner safety shut off valve trains consisting of pneumatic double block and bleed valves with 150# raised face flanges at the boundaries.

Components used in the valve train are listed in Table 2.

**Table 5**
**Valve Train Components**

Pressure, Temperature and Flow Transmitters (HART Compatible) – Rosemont
Solenoid Valves – Asco
Pressure Switches – Ashcroft
Pneumatic Control Valves – Fisher
Isolation Valves – Wey or Delta
Pneumatic Safety Shutoff Valves

Skid to be painted as per the specification. All components will be wired back to a NEMA 4X junction box. A typical valve train skid is shown in Figure 6.

**Figure 6**
**Typical Gas Valve Train**

The valve trains will be designed and supplied while maintaining a size that fits ideally within the locations around the boiler. A typical layout of the main gas train is shown in Figure 7.

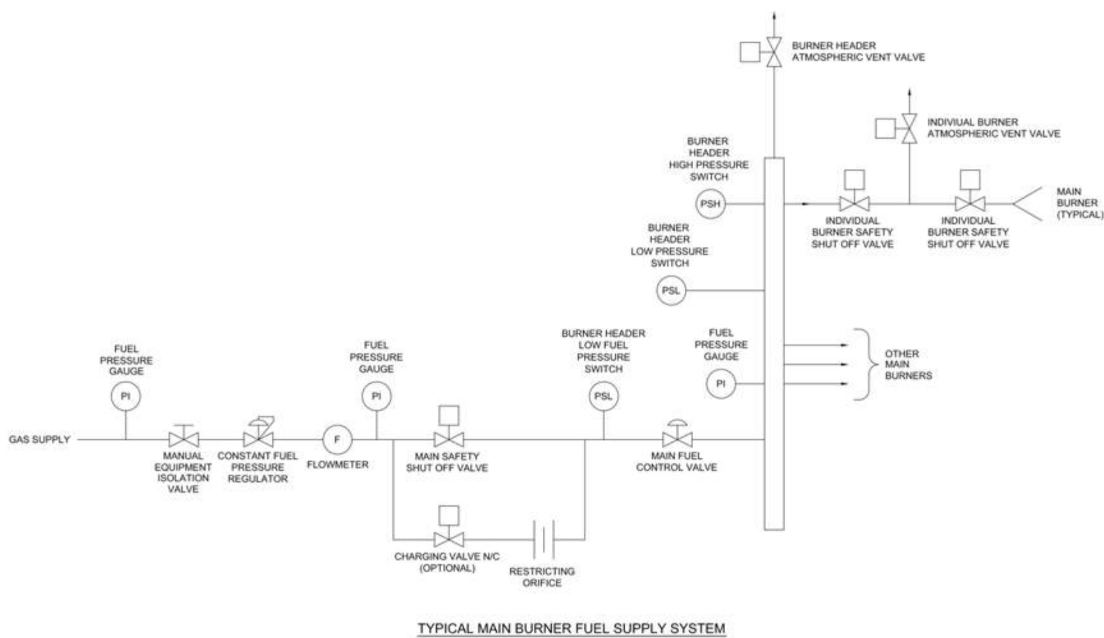



**Figure 7**
**Main Burner Valve Train**

A written control system description, that meets NFPA recommendations, will be provided for the plant to program the existing CCS and BMS.

## 3.5 FGR / IFGR System Design and Supply

STEP will supply a flue gas recirculation system for enhanced NOx control. Depending on the physical boiler layout the system would either have a fan to direct 10% of the flue gas to the FD fan outlet. Another approach is to duct 10% flue gas from the stack inlet to the FD fan inlet. Flue gas reduces the percentage of oxygen available for combustion in the near burner zone. This will reduce the peak flame temperature and NOx formation. CFD modeling is used to determine the flue gas amount and flow path through each system. A brief description of each system is listed below.

### 3.5.1 FGR System

A fan assisted FGR system would require a fan with capacity of 10% flue gas flow at discharge pressure of 10" Wc. A variable speed drive would control the amount of flue gas recirculated over the load range. Flue gas would flow through ductwork from the stack inlet to isolation damper at the FGR fan inlet. At the fan outlet the FGR would flow through a discharge damper and split to distribution headers at each of the FD fans outlets. The system would consist of the following components:

- Stack inlet connection duct
- Two (2) isolation dampers with actuators
- FGR Fan
- ¼" thick carbon steel duct
- Expansion joint
- FD fans inlet duct distribution headers

### 3.5.2 IFGR System

An induced flue gas recirculation system utilizes the existing FD fans to draw flue gas from the stack inlet and mix with the incoming combustion air at each of the FD fan inlets. The system has the following components:

- Stack inlet connection duct
- Control damper at FD fan inlet with actuator
- Fan inlet distribution duct at each fan
- Expansion joint
- ¼" thick carbon steel duct

## 3.6 Over Fire Air (OFA) System

STEP will design and supply an OFA system for each of the boilers. The OFA system will take combustion air from the existing wind boxes and duct to OFA ports located above the to row of burners. It is anticipated that for all boilers up to 15% of the combustion air will be directed to the OFA ports. Directing combustion air to the upper furnace will reduce the peak flame temperature and stage combustion throughout the boiler. CFD modeling is used to validate the OFA system design, which will consist of the following components:

- ¼" thick carbon steel duct
- OFA Ports, Bent Tube Openings and Seal Boxes
- Expansion joints
- Control damper with actuator

# 4.0 COMMERCIAL ITEMS

## 4.1 Program Schedule

The lead-times for the major project items are as follows:

### 4.1.1 Gas Conversion on a per Unit Basis

| | |
|---|---|
| Site Evaluation | 1 Week |
| Component Design & CFD Modeling | 3 Weeks |
| Design Review by Client | 1 Week |
| Burner Fabrication | 12 Weeks |
| Shipment to Site | 1 Week |

## 4.2 Terms of Payment

The terms of payment are outlined in Section 2 of this proposal, Pricing, subject to Client and STEP agreeing to terms and conditions. Payment is based on completion of specific tasks. The tasks and payments are as follows:

| | |
|---|---|
| • Award of Purchase Order | 10% |
| • Completion of CFD model, engineering and Design | 30% |
| • Delivery of Hardware to Site | 20% |
| • Completion of Installation of Hardware | 20% |
| • Completion of Guarantee Testing | 20% |

Locke Equipment
PO Box 243
Shawnee Mission, KS 66201
913-782-8500

Associated Mechanical, Inc.
PO Box 2448
Shawnee Mission, KS 66201
913-815-1108

| | |
|---|---|
| **Date:** | **1/13/2017** |
| **To:** | **Black and Veatch** |
| **Attn:** | **Tom Trimbel** |
| **From:** | **Tim Locke** |
| **Re:** | **Gas Conversion of Confidential Customer Units 1, 2, and 3** |

**Quotation: 201612-71882A-R0**

Dear Tom:

Locke Equipment Co. Inc. and John Zink Hamworthy Combustion (JZHC) appreciates this opportunity to offer supply of gas firing equipment for a confidential customer.

We are committed to supplying quality engineering services and equipment for many plants throughout the world. Customer satisfaction is our highest priority and every effort is made to provide unparalleled service and customer support. We look forward to be of service and working with your company on this project.

This is a budgetary proposal and is intended only as an estimate to facilitate your planning processes; it does not constitute a commitment or firm offer to sell goods or services at the prices and terms referenced herein. Any firm offer or binding quotation will be the subject of a formal proposal at a future date.

Please be sure to contact me if you have any questions or comments about our quotation.

Sincerely,

Tim Locke

# Quotation 201612-71882A-R0

**GAS ADDITION**

**FOR**
**CONFIDENTIAL CUSTOMER**

*Prepared by:*

Locke Equipment Company
15705 S US 169 HWY
Olathe, Kansas  66062

Jan 13, 2017

# CONTENTS

## SUMMARY

Locke Equipment is pleased to submit our budgetary proposal for gas conversions of three CONFIDENTIAL boilers. Based upon our database the boilers are identified as Units 1, 2, and 3 at Kentucky Utilities E.W. Brown Generating Station in Harrodsburg Kentucky.

The proposed workscope consists of the following:

Unit #1 is wall-fired with 16 burners, total heat input 1262 mmBtu/hr.

- 16 low NOx gas burners, approximately 80 mmBtu/hr
- 16 FyrBolt igniters, 8 mmBtu/hr
- 16 iScan2™ direct sight flame scanners, 30 ft cable, J-box, power supply
- 1 high pressure station header valve train, 4”x6”
- 1 low pressure burner header valve train, 6”x12”
- 16 local burner valve trains, 3” with flexible gas hose
- 1 igniter header valve train, 1¼”x3”
- 16 local igniter valve trains, 1¼“ with flexible gas hose
- 1 CFD analysis for airflow and furnace combustion
- 1 Boiler impact study for fan performance and thermal profile
- 1 BMS engineering logic with graphic sketches for DCS
- Freight to site
- Engineering for the equipment above (see Section 0)
- Preliminary allotment of field services (see Section 0)
- NOx emissions estimated at 0.32 lb/mmBtu with 600°F windbox air, without FGR or OFA. CO emissions estimated at less than 0.074 lb/mmBtu.

Unit #2 is tilting tangential fired with 16 burners, total heat input 1843 mmBtu/hr.

- 16 tilting low NOx gas burners, approximately 115 mmBtu/hr
- 16 FyrBall gas igniters, 12 mmBtu/hr
- 16 iScan2™ UV-FOX flame scanners, 30 ft cable, J-box, power supply
- 16 iScan2™ direct sight flame scanners, 30 ft cable, J-box, power supply
- 1 high pressure station header valve train, 6”x6”
- 1 low pressure burner header valve train, 6”x16”
- 16 local burner valve trains, 3” with flexible gas hose
- 1 igniter header valve train, 1½”x3”
- 16 local igniter valve trains, 1¼“ with flexible gas hose
- 1 CFD analysis for airflow and furnace combustion
- 1 Boiler impact study for fan performance and thermal profile
- 1 BMS engineering logic with graphic sketches for DCS
- Freight to site
- Engineering for the equipment above (see Section 0)

- Preliminary allotment of field services (see Section 0)
- NOx emissions estimated at 0.32 lb/mmBtu with 600°F windbox air, without FGR or OFA. CO emissions estimated at less than 0.074 lb/mmBtu. The boiler is understood to have two OFA ports installed but with unknown arrangement or airflow quantity.

Unit #3 is tilting tangential fired with 20 burners, total heat input 4822 mmBtu/hr.

- 20 tilting low NOx gas burners, approximately 242 mmBtu/hr
- 20 FyrBall gas igniters, 12 mmBtu/hr
- 20 iScan2™ UV-FOX flame scanners, 30 ft cable, J-box, power supply
- 20 iScan2™ direct sight flame scanners, 30 ft cable, J-box, power supply
- 1 high pressure station header valve train, 6”x6”
- 1 low pressure burner header valve train, 6”x16”
- 20 local burner valve trains, 3” with flexible gas hose
- 1 igniter header valve train, 1½”x6”
- 20 local igniter valve trains, 1¼“ with flexible gas hose
- 1 CFD analysis for airflow and furnace combustion
- 1 Boiler impact study for fan performance and thermal profile
- 1 BMS engineering logic with graphic sketches for DCS
- Freight to site
- Engineering for the equipment above (see Section 0)
- Preliminary allotment of field services (see Section 0)
- NOx emissions estimated at 0.42 lb/mmBtu with 600°F windbox air, without FGR or OFA. CO emissions estimated at less than 0.074 lb/mmBtu. The boiler is understood to have four OFA ports installed but with unknown arrangement or overfired airflow quantity. To achieve NOx emissions less than 0.10 lb/mmBtu, approximately 25% FGR in combination with 25% OFA will be required.

**Additional Work Supplied by Locke**

In addition to the above described materials and services, Locke and JZHC will supply:

- The services of Locke and or JZHC’s project engineer for each of the following meetings:
    - One project kick-off meeting at site
    - One design review meeting by teleconference
    - One Factory Acceptance Test (FAT) of equipment at JZHC's manufacturing shop
    - Progress review meetings by teleconference
- Progress reports, updated monthly during project engineering, and updated upon significant events during fabrication, until notice of equipment readiness for shipment.
- All design engineering and project management for the equipment supplied by JZHC, with project documentation submitted electronically on a timely basis per the Contract milestones, including:
    - Arrangement drawings for approval
    - Bill of materials for approval
    - Certified drawings to proceed with fabrication

- I/O list, alarm and trip set point list, instrument data list, utility consumption rates (electrical power, service air, instrumentation air), equipment sizes and weights, recommended pull space requirements, and valve list.
- Project schedules
- Equipment inspection and test plan (ITP)
- Recommended spare parts list
- Installation, operation, and maintenance (IOM) manual submitted prior to shipment of the equipment, which will be sufficient for initial installation, checkout, startup, operation, shutdown, and maintenance of the equipment designed or supplied by JZHC. The IOM manual will include (where applicable): predicted performances (including fuel flowrates vs. pressure curves), guaranteed performances, commissioning and startup checklist, equipment tuning procedure, and guarantee testing procedure. Revisions to the IOM manual will be submitted following startup, tuning, and commissioning of the JZHC equipment, and will include (where applicable): as-built drawings, results of tuning and guarantee tests, and final recommended operating conditions and procedures.
- This proposal includes preparation and delivery of IOM documentation as an estimated six (6) bound hard copies and two (2) electronic copies on CDs. If requested prior to the initial printing, a limited number of additional copies of the final IOM manuals (paper and/or CD) may be provided at no additional charge (at our discretion). Subsequent copies may be provided for a nominal additional price. Locke's customer, the end user, and/or their designees will be permitted to make additional unlimited number of copies of the IOM documentation for distribution exclusively to the end user.
- Customer's instrument tag numbers will be included on the documentation if the tag numbers are provided by the customer.
- All electronic documentation will be provided as PDFs or TIFs. Some documents may also be provided in other formats, as specified by the Contract.

- Accessibility will be provided to Locke & JZHC's customer, the end user, and/or their designees to witness QA and QC testing at JZHC's manufacturing facilities, to inquire about project schedule, and to occasionally observe progress of key project assemblies on the production floor. JZHC will provide notice at least two weeks prior to anticipated readiness for the QA and QC testing. Each burner assembly will be subjected to QA and QC testing, and each burner assembly will be provided with written documentation of the test results. Each assembly will be built into the most complete and largest practical sizes to minimize field erection time.
- We will package the proposed equipment into land crating, as appropriate. The terms for freight are described in the Pricing Terms of this proposal.

**Field Services**

Locke can provide on-site field services during installation, checkout, startup, tuning, commissioning, and/or operator training, for equipment supplied by JZHC. Due to the inherent variability of field service activities, all JZHC Field Services will be invoiced for the actual hours and expenses, per JZHC's applicable *Technical Assistance Agreement*.

For your budgeting purposes, Locke is providing an estimated lump-sum allotment of field services, based upon the following assumptions:

- On site support for each boiler will be provided for a total duration of 20 days, scheduled as one man at 6 days per week at 10-hours per day, plus travel time and travel-related expenses. Two travel trips from outside the area are included.

- Labor performed in excess of 8-hours per weekday, and anytime during weekends or holidays, is subject to overtime rules. If applicable, overtime premiums are already included in the lump sum allotment. Estimates for the overall duration for installation, startup, commissioning, and tuning assume no delays due to other causes.
- The installation, operating and maintenance (IOM) instructions as provided by JZHC are generally comprehensive and complete, and can be readily understood by qualified persons. These instructions are comprehensive and generally sufficient for operating plants to perform all of the necessary installation, operations, and maintenance for our equipment without the support of Field Services. When our Field Service personnel are on site, we will support the installation and can show the plant O&M personnel how to remove, service, and reinstall our equipment. Our IOM manual will be used as the reference materials for any training.
- The customer may assign one or two of his qualified plant personnel to observe the setup and tuning of JZHC equipment as on-the-job training. This hands-on training is usually sufficient for trainees to comprehend the overall requirements of the systems, to make basic adjustments on their own, or to follow directions from Field Services during more complicated activities. The Field Services allotment does NOT include formal classroom training sessions.
- It is not likely that all of the aforementioned activities would be performed sequentially in one uninterrupted sequence; therefore multiple round trips of travel are anticipated to the site.
- An allotment of field services is offered for budgeting purposes. To encourage the use of JZHC's qualified technical services and promote an overall beneficial outcome for the project, the lump sum allotment of field services is offered at a discount from our standard rates. Additional labor hours in excess of the allotment will be invoiced per *JZHC's Technical Assistance Agreement.*

## EXCLUSIONS AND CLARIFICATIONS

It is assumed for the purpose of this proposal that the following equipment exists in good working order, will be designed and supplied by others, or that Locke Equipment may provide additional proposals for these items.

### Exclusions

The following engineering, equipment, and services are NOT included in this proposal:

Coal burners

Combustion air windbox,

Burner airflow control devices

Fans, blowers, dampers, actuators, motors, switchgear, ducting, etc.

Overfire air systems

Flue gas recirculation systems

Local control panels

Analyses or modifications to structural steel

Analyses or modifications to boiler pressure parts

Equipment or services for field calibration of any instrumentation

Supply of consumables, including fuel(s), purge gas, instrument air

BMS programming, hardware, or implementation. JZHC will supply a narrative operating sequence and logic diagrams.

Boiler control system (BCS) or combustion control system (CCS) logic. JZHC will provide a list of requirements for operating the combustion equipment.

DCS engineering, programming, hardware, or implementation

Design or materials for interconnecting piping, tubing, conduit, or wiring, except as may be specified in this proposal

Refractory, insulation, lagging, casing (if existing burner throat refractory is in “good condition”, then Locke does not require its replacement)

Regulatory permitting, PSD calculations, expert witness testimony

Stack emissions testing

Any materials or labor for the abatement, demolition, removal, disposal, installation, modification, operation, adjustment, or maintenance of any equipment, regardless of whether the equipment was supplied or not supplied by Locke, except if such materials or labor are specifically identified in this proposal as included in Locke's workscope. It has been assumed that all such unspecified materials and labor will be provided and paid for by others independently of this proposal.

### Clarifications

The following are clarifications:

- It is essential for the end user to accurately define all required emission rates (e.g., NOx, CO, VOC, PM, opacity, etc.) as well as any other limitations prior to start of project engineering.
- Locke is not offering any performance guarantees for the boilers. With addition of oil or gas fuels to coal-fired boilers, or addition of gas to oil-fired boilers, boiler performance may be affected to

the extent that a fraction of the total boiler heat absorption is shifted from the lower furnace into the convection pass.

- Locke will provide P&IDs and arrangement drawings only for new equipment or engineering designs as supplied byLocke, but not for existing equipment.
- Locke may supply detailed drawings of valve trains, enclosures, and wiring diagrams in AutoCAD. However, drawings of our proprietary components (igniters and burners) will be supplied in PDF.
- A list of recommended spare parts will be developed during project engineering. We will work with the customer to determine typical stocking and usage patterns, and will provide a separate price list.
- Locke can provide the following information after project award and during project engineering:
    - Utility consumption rates (electrical power, service air, instrument air)
    - Recommended pull space requirement
    - Control cabinet sizes and weights
    - Valve skid sizes and weights
- If Locke has *not* provided a separate price to provide our field services support during installation and checkout of equipment, or training of operation and maintenance personnel, we will be pleased to discuss the customer's expectations for Locke's portion of the field services work and provide a price.

## SCHEDULE

Locke assumes that our standard delivery times are acceptable. Earlier deliveries may be possible but must be confirmed with our factory.

The project schedule is dependent upon receipt of a valid purchase order and suitable design information (Section 0). For the proposed workscope, the overall elapsed duration from arrival of an acceptable purchase order until availability for shipment is typically estimated at 36-42 weeks, plus time required by customer for review and revisions of JZHC submittals. Estimated schedule milestones for this project are:

- Preliminary general arrangement drawings and bill of materials will be submitted for approval within about 8-10 weeks after receipt of order and complete design information from customer. Specific long-lead items could be ordered at this time upon release by the customer.
- Customer review and approval of Locke & JZHC's drawing submittal (duration determined by customer).
- Certified drawings will be submitted within about 1 to 2 weeks after receipt of customer's review comments; actual time to issue certified drawings will depend upon type and extent of customer's comments. Locke & JZHC will be considered fully released for fabrication at this event without further acknowledgement from the customer, unless the customer requires a second review cycle.
- Receipt of materials, fabrication, and availability for shipment, within about 24-30 weeks after full release for fabrication. Actual duration between approval of certified drawings and shipment will depend upon whether release was given to purchase specific long-lead items before approval of certified arrangement drawings.

These proposed schedule milestones will be reevaluated and a revised project schedule will be issued within about two weeks after acceptance of the customer's purchase order.

### Required Information

The following design information will be required from the customer for completing engineering design:

- Confirmation of operating and design parameters.
- General arrangement drawings (plan and elevations) of the existing equipment.
- General arrangement drawings (plan and elevations) of the intended installation space for new equipment.
- Thermal expansion data for the boiler to develop design specifications for flexible hose connections.
- If suitable accurate drawings or dimensional information are not available, a Locke design engineer will visit the site to obtain documentation and measure required dimensions. Labor and travel for the site visit will be invoiced per our *Technical Assistance Agreement*.

## COMMERCIAL

### Price

The following prices are provided for engineering, equipment, and services as described within this quotation, total quantities for two boilers:

| Item | Section | Qty | Description | Total, USD |
|---|---|---|---|---|
| 1 | 1 | 1 lot | Equipment for Unit #1 Gas Conversion | $3,610,000 |
| 2 | 1 | 1 lot | Equipment for Unit #2 Gas Conversion | $3,540,000 |
| 3 | 1 | 1 lot | Equipment for Unit #3 Gas Conversion | $4,350,000 |
| | | | **TOTAL BASE EQUIPMENT PRICE** | $11,500,000 |

### Pricing Terms and Conditions

This quotation is subject to the following Terms and Conditions.

- This is a budgetary proposal and is intended only as an estimate to facilitate your planning processes; it does not constitute a commitment or firm offer to sell the goods or services at the prices and terms referenced herein. Any firm offer or binding quotation may be the subject of a future proposal.
- Prices are in U.S. Dollars.
- Prices do not include any taxes
- Prices do not include any insurance, bonding, letters of credit, or bank guarantees. A certificate of insurance will be provided before JZHC begins on-site field services.
- Equipment prices do not include spare parts, except as may be supplied and replaced by JZHC during startup and commissioning, for Warranty replacements, or as may be separately described in this proposal.
- Equipment prices include preparation for shipment, including appropriate packing and crating for the designated method of shipment.
- Equipment prices include freight from JZHC's factory to Customer's destination. If a separate price for freight is quoted, then such price will be based upon the specified destinations, number of deliveries, and shipping methods.
- JZHC products may be manufactured at any location and may include sources inside or outside the USA, at JZHC's sole discretion.
- Except where mutually agreed, all equipment and/or services quoted are subject to the attached *John Zink Company, LLC General Terms and Conditions of Sale*. Our offer to sell the goods or services is specifically contingent upon acceptance of these Terms and Conditions. At our sole discretion, other terms and conditions may be mutually negotiated prior to placement of order, but may result in adjustments to prices, schedules, or other conditions. If resulting in an order, this proposal (including without limitation, the Terms and Conditions) shall be incorporated by reference into any resulting Contract Documents. In case of a conflict among the Contract Documents, then the terms of this proposal (including without limitation, the Terms and Conditions) shall take precedence.
- Equipment prices do not include on-site Technical Assistance (field services). JZHC field services will be invoiced per their actual hours and expenses, per JZHC's *Technical Assistance*

*Agreement*. Invoices for Technical Assistance will be based upon the labor rates in effect on the dates that services are performed. Technical Assistance labor rates are generally adjusted not more than once per year.

- With the exception of prices for Technical Assistance activities, all prices are valid through scheduled delivery of all supplied equipment, provided we accept a Purchase Order or a Letter of Intent by **March 15, 2017**. Thereafter, we reserve the right to re-quote the price.
- Prices are based upon the specific numbers and dates of deliveries quoted herein. We will confirm a Contractual Delivery Date upon acceptance of an executed Purchase Order or Letter of Intent. Escalation charges shall be applied to orders whose delivery dates are delayed beyond thirty (30) days from the Contractual Delivery Date due to no fault of the supplier and when such delay has caused an increase in the cost of the goods or services tour manufacturer, including, but not limited to moving and storage fees. Escalation charges shall be based upon either: (1) the Producer Price Index as published by the U.S. Department of Labor, Bureau of Labor Statistics for Finished Goods, Capital Equipment only, or (2) the U.S. Department of Labor, Employment Cost Index (ECI), Private Industry, Table 3 Employment Cost Index for total compensation for private industry workers, by industry and occupational group; Manufacturing Industry, as applicable. The base line for calculating the escalation adjustment shall be the date of the contract.

**Payment Milestones**

Subject to the manufacturer’s review and approval of the purchaser's credit ratings, and assuming that all equipment is ordered as one order and shipped as one shipment, the following invoice and progress payment schedule will be required:

- 20% of the Equipment Price upon issuance of the Purchase Order
- 30% of the Equipment Price upon submittal of certified arrangement drawings. We will be considered fully released for manufacture without further acknowledgement from the customer.
- 40% of the Equipment Price six weeks after submittal of certified drawings
- 10% of the Equipment Price upon notice of availability for shipment
- 100% of the Field Services price attributed to ongoing activities, invoiced for actual time, materials, and expenses
- Payment of all invoices shall be Net 30 days.
- Invoices and payments may be submitted by electronic means.

## GUARANTEES

The following general notes are applicable to the Performance Guarantees.

1) All guarantees stated in this Section apply only to the equipment proposed herein.
2) All performance specifications stated throughout this proposal are intended to show probable operating results only which cannot be guaranteed except as expressly stated within this Section.
3) Testing for Performance Guarantees shall be run within **sixty (60) days** after equipment has been shipped, or within **30 days** after the equipment has been installed and first operated, whichever occurs earlier. Prior to testing, a trained service engineer shall tune the equipment to assure that Performance Guarantees can be met during the Performance Tests. Performance Tests will be conducted at steady state operating conditions, and in a manner to ensure that the specified operating conditions are being maintained. We will be allowed to observe the Performance Testing and will be supplied a complete copy of all test data and results. Others shall supply all operating personnel and equipment for such tests, including development of test protocols for regulatory submittal, supply of all consumables (fuel(s), etc.), stack emissions sampling, acquisition and analyses of fuel samples by a qualified independent test laboratory (including analyses for trace fuel bound nitrogen (FBN) using acceptable analytical method), data reduction, and reporting.
4) The equipment shall be considered accepted if the Performance Tests show that the Performance Guarantees have been fulfilled, or if the equipment is not tested within the specified period. In case of the failure to meet the Performance Guarantees, we shall be provided with ample opportunity to analyze the circumstances, and to perform a reasonable correction. We reserve the right to modify, change, or replace, on a straight time basis, the furnished equipment so that Performance Guarantee(s) will be obtained.
5) The Performance Guarantees are valid only when the equipment is installed, operated, and maintained specifically according to the following (listed in order of decreasing precedence):
   a) Safe operating practices,
   b) Our IOM instructions,
   c) Our Engineering Design Basis determined during project engineering, and
   d) Design Data as specified in this proposal.
6) All boiler/heater fireside surfaces must be thoroughly pressure washed prior to the emissions testing with all loose debris removed from inside the windbox, generating tubes, superheater, economizer, airheater, and duct surfaces.
7) Dimensional drawings of all boiler/heater including existing burner arrangements, internal furnace dimensions, tube wall openings, and refractory locations, are required for validation of Performance Guarantees.

**Burner Heat Input**

We guarantee that each burner will provide the maximum heat inputs stated herein, when firing the specified fuels and pressures supplied at the burner inlets.

The burner(s) flame will have no deleterious impingement over the entire burner turndown range as per the American Boiler Manufacturers Association Definition: “Flame impingement is defined as the condition which exists when the flame resulting from the combustion of the fuel comes into contact with any interior surface of the furnace in such a way as to result in localized incomplete combustion of the fuel and such condition manifests itself in the formation of hard carbonaceous deposits at the contact location. Flame impingement is a condition of firing a fuel which may cause failure and/or excessive maintenance of combustion chamber wall surfaces.”

**Emissions**

Based upon the information provided, we would guarantee the following maximum emission levels (lb/mmBtu) on natural gas:

| Controls | Without FGR or OFA | | | 25% FGR and 25% OFA |
|---|---|---|---|---|
| **Emissions** | **Unit 1** | **Unit 2** | **Unit 3** | **Unit 3** |
| NOx | 0.32 | 0.32 | 0.42 | 0.10 |
| CO | 0.074 | 0.074 | 0.074 | 0.074 |

Emission performance guarantees are based upon the following limitations:

(a) Boiler heat input from 25% to 100% Boiler Maximum Continuous Rating (BMCR).

(b) PPM concentrations (wherever provided) are corrected to 3 percent oxygen by volume on a dry basis.

(c) While firing only the -supplied equipment with the subject fuel type(s) and/or fuel constituents as proposed herein.

(d) While operating at the Design Data conditions. All information provided in the Design Data is preliminary only and is subject to change after the detailed Engineering stage on the contract is completed.

(e) Emissions will be measured in the stack by a qualified independent third-party, contracted and paid by the customer, using the most current EPA standard test methods per 40 CFR Part 60 Appendix A (Method 7E for NOx, Method 10 for CO). No other emission guarantees are extended, including but not limited to VOCs, GHGs, PM, PM10, PM2.5, SO2, SO3, H2SO4, metals, or any other species.

(f) Emission guarantees exclude background emissions present in the combustion air.

(g) The boiler tube walls must be reasonably clean of ash deposits in the burner zone.

(h) For boilers with the furnace and generating bank separated by furnace tubes, the furnace tubes must form a gas tight seal to prevent short circuiting of furnace gases into the boiler gas outlet.

(i) Dimensional drawings or confirmation of specific boiler properties are required for validation of emission guarantees, including: existing burner arrangements, internal furnace dimensions, tube wall openings, and refractory locations.

(j) The following refractory locations and coverages in the boiler:

a. Floor 0%

b. Ceiling 0%

c. Front Wall 0% (except burner throats)

d. Rear Wall 0%

e. Left Wall 0%

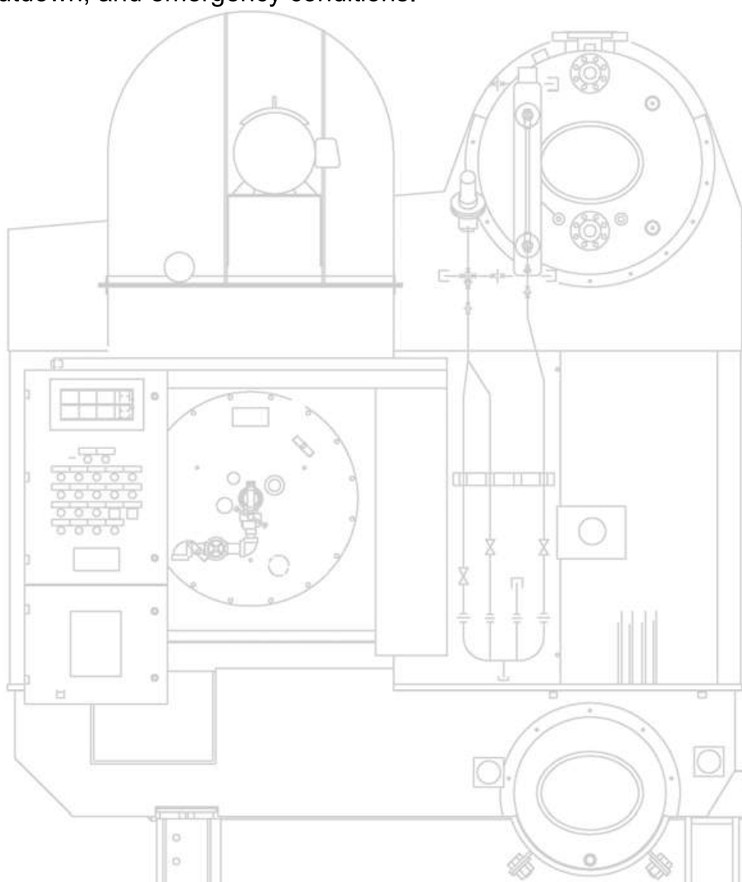
f. Right Wall 0%

**Stack Opacity**

We guarantee that incremental stack opacity will be less than 10% while firing only JZHC igniters or gas burners. Incremental opacity is defined as the measured opacity (6-minute rolling average in stack) during warm-up gun operation minus the baseline opacity (6-minute rolling average in stack, in the period immediately before initiating operation of JZHC igniters).

**Noise**

We guarantee that the noise levels from the furnished equipment will not exceed 85 dBA when measured at 3 feet from major surfaces of the equipment and/or enclosures, and at 5 feet height above the nearby operating floor, based upon each point source measured independently in a free field, during steady state operating conditions, excluding reflections, after subtracting background noise, and exclusive of abnormal, startup, shutdown, and emergency conditions.



**IHI INC.**
Power Plant Engineering Division
7285 West 132nd Street, Suite 200,
Overland Park, KS 66213
TEL: (913) 632-0150
FAX: (913) 632-0185

# Budgetary Proposal for Coal-to-Gas Conversion Project Submitted January 19, 2017

**Submitted to:**

**Black & Veatch Corporation**

# IHI INC.

Power Plant Engineering Division
7285 West 132nd Street, Suite 200, Overland Park, KS 66213
TEL: (913) 632-0150 FAX: (913) 632-0185

**Date: January 19, 2017**
**Ref No: INTB - 17008**

**To: Black & Veatch Corporation**
**Attn.: Mr. Tom Trimble**

**SUBJECT: Budgetary Proposal for Coal-to-Gas Conversion Project**

Dear Tom,

In accordance with your request dated December 12, 2016, we are pleased to submit our budgetary proposal for the Coal-to-Gas Conversion Project.

If you have any questions, please do not hesitate to contact us at any time. We look forward to working with you and your team on this project.

Sincerely yours,

Glenn Lansford
Sr. Vice President – Managing Director
IHI INC.
Tel. 913-632-0110
Cel. 913-901-7565
Email. galansford@ihi-us.com

※THIS BUDGET PROPOSAL IS NON－BINDING, AND WAS PREPARED FOR YOUR EXCLUSIVE REFERENCE

## 1.BUDGETARY PRICED PROPOSAL:

(USD)

| Item | Unit1 | Unit2 | Unit3 |
|---|---|---|---|
| Burner | $2,574,000. | $1,642,000. | $2,074,000. |
| SOFA | $580,000. | NA | NA |
| FGR System | $1,718,000. | NA | NA |
| Natural Gas Valve Trains ※1 | $1,849,000. | $1,611,000. | $3,224,000. |
| Travel Expenses | $179,000. | $97,000. | $102,000. |
| **Total** | **$6,900,000.** | **$3,350,000.** | **$5,400,000.** |

※1 : The quantity for Natural Gas Valve Trains for each unit is as follows ;

| Item | Unit1 | Unit2 | Unit3 |
|---|---|---|---|
| Natural Gas Inlet Pressure Reduction Station | 1set | 1set | 1set |
| Main Gas Header | 1set | 1set | NA |
| Main Gas Header Vent Spool | 1set | 1set | NA |
| Igniter Gas Header | 1set | 1set | 1set |
| Igniter Gas Header Vent Spool | 1set | 1set | 1set |
| Local Burner/Igniter Valve Trains | 16sets | 12sets | 16sets |
| Elevation Gas Headers | NA | NA | 4sets |
| Elevation Gas Header Vent Spool | NA | NA | 4sets |

## 2. SCOPE OF SUPPLY:

Per the attached TECHNICAL SPECIFICATION FOR GAS CONVERSION

## 3. DELIVERY:

Ex-Works Factory, per Incoterms 2010

## 4. COMMERCIAL CONDITIONS:

To be discussed later when we submit our firm proposal.

## ATTACHMENT:

* TECHNICAL SPECIFICATION FOR GAS CONVERSION (IHI Specification No.9377269-00)

*******************************************************************************

Messrs. BLACK & VEATCH CORPORATION

# TECHNICAL SPECIFICATION

# FOR

# GAS CONVERSION

IHI Specification No. 9377269-00

January 2017

Document Control

| No. | DATE | DESCRIPTION | DRAWN | DESIGNED | CHECKED | APPROVED |
|---|---|---|---|---|---|---|
| 0 | 19th January 2017 | First issued | T. I. 19th Jan, '17 | 19th Jan '17 | 19/Jan/'17 | 19.Jan.'17 |
| | | | | | | |

TABLE OF CONTENTS

# CHAPTER 1. GENERAL INFORMATION

## SECTION 1.1 GENERAL

1. This specification covers engineering, materials, and fabrication about Gas Conversion for a Confidential Client located in the central United States with three (3) coal fired power plants located on the same site.

2. The parts described herein will be designed and manufactured with the long experienced superior engineering and the skilled workmanship of IHI Corporation.

## SECTION 1.2 LANGUAGE AND UNITS

The language for all official communication, documents and drawings will be described in English. U.S. customary unit will be applied to all of the actual designing works.

## SECTION 1.3 DEFINITION OF TERMS

1. Messrs. Black & Veatch Corporation is defined as “Purchaser”.
2. IHI Corporation is herein referred as “IHI”.

## SECTION 1.4 CODES AND STANDARDS

1. GENERAL

   The parts proposed here will be designed and manufactured in accordance with the following codes and standards.

2. PRESSURE PARTS

   Pressure parts will be designed in accordance with the codes and standards below.

   ASME : American Society of Mechanical Engineers
   ASTM : American Society of Testing and Materials

3. NON-PRESSURE PARTS

   Non-pressure parts will be designed in accordance with the following codes and standards and IHI standard material selection.

   ASME : American Society of Mechanical Engineers
   ASTM : American Society of Testing and Materials
   ANSI : American National Standards Institute
   AISC : American Institute of Steel Construction
   AWS : American Welding Society
   JIS : Japanese Industrial Standards

## SECTION 1.5 DESIGN CONDITION

1. GENERAL

The followings show the general description for each boiler.

(1) Unit 1

Unit 1 is a 114 MW (gross) rated Babcock & Wilcox front wall fired, split furnace, pulverized coal boiler that houses sixteen (16) coal burners, four levels of four burners per level, commissioned in 1957. The unit utilizes No. 2 fuel oil for igniters/warm-up. The unit design conditions are indicated in Table 2. Particulate emissions are controlled by an electro-static precipitator (ESP), and share a flue gas desulphurization (FGD) system and a stack with Units 2 and 3. The unit does not have a selective catalytic reduction (SCR) system.

(2) Unit 2

Unit 2 is a 180 MW (gross) rated Combustion Engineering tangential-fired, single furnace, pulverized coal boiler that houses sixteen (16) coal burners, commissioned in 1963. The unit utilizes No. 2 fuel oil for igniters/warm-up. The unit design conditions are indicated in Table 2. Particulate emissions are controlled by an electro-static precipitator (ESP), and share a flue gas desulphurization (FGD) system and a stack with Units 1 and 3. The unit does not have a selective catalytic reduction (SCR) system.

(3) Unit 3

Unit 3 is a 457 MW (gross) rated Combustion Engineering tangential-fired, single furnace, pulverized coal boiler that houses twenty (20) coal burners, commissioned in 1971. The unit utilizes No. 2 fuel oil for igniters/warm-up. The unit design conditions are indicated in Table 2. NOx emissions are controlled by a selective catalytic reduction (SCR) system. Particulate emissions are controlled by a bag house, and share a flue gas desulphurization (FGD) system and a stack with Units 1 and 2.

Each of the boilers is equipped with the following equipment (Table 1).

Table 1-1 Major Boiler Components

| | UNIT 1 | UNIT 2 | UNIT 3 |
|---|---|---|---|
| Number of Burners | 16 | 16 | 20 |
| Number of OFA ports | 0 | 2 | 4 |
| Number of FD fans | 2 | 2 | 2 |
| Number of ID fans | 1 (single speed) | 2 (two speed) | 2 (two speed) |
| Precipitator | 1 | 2 box | Bag house |
| SCR | No | No | Yes |
| FGD | Shared | Shared | Shared |
| Stack | One (1) shared | One (1) shared | One (1) shared |

2. EXISTING BOILER CONDITION

The following boiler characteristics and existing conditions shall be used for design and sizing of the burners:

Table 1-2 Units Design Conditions (Coal Fired)

| | UNITS | UNIT 1 | UNIT 2 | UNIT 3 |
|---|---|---|---|---|
| | | 100% Coal | 100% Coal | 100% Coal |
| Size, rated capacity, gross | MW | 114 | 180 | 457 |
| Commercial Date | NA | 1957 | 1963 | 1971 |
| Burners | No. | 16 | 16 | 20 |
| Burner/Arrangement type | NA | Front wall | Tangential | Tangential |
| Main Steam Flow Rate | lb/h | 840,000 | 1,250,000 | 3,350,000 |
| Main Steam Pressure, SH outlet | psig | 1,525 | 1,870 | 2620 |
| Main Steam Temp, SH outlet | °F | 1,005 | 1,005 | 1,005 |
| Reheat Steam Temp, RH outlet | °F | 1,005 | 1,005 | 1,005 |
| Flue Gas Temp, Leaving AH (corrected) / (uncorrected) | °F | 286 / 300 | 286 / 300 | 282/290 |
| Feedwater Inlet Temperature | °F | 465 | 459 | 488 |
| Mills | | | | |
| Type | | Exhauster | Exhauster | Exhauster |
| Number | | 4 | 4 | 5 |
| Combustion System | | | | |
| Forced Draft Fans | No. | 2 | 2 | 2 |
| Induced Draft Fans | No. | 1 | 2 | 2 |
| Air Heater | | | | |
| Type | | Bi-sector | Bi-sector | Bi-sector |
| Number per Unit | | 2 | 2 | 2 |
| Air Heater | | | | |
| Leakage (assumed) | % | 10.0 | 10.0 | 10.0 |

3. CURRENT EMISSIONS

The units currently operate with the following emissions at the Stack outlet.

Table 1-3 Units Emissions Criteria (Coal Fired)

| | | UNIT 1 | | UNIT 2 | | UNIT 3 | |
|---|---|---|---|---|---|---|---|
| | UNITS | MIN LOAD 35 % MCR | 100% MCR | MIN LOAD 39 % MCR | 100% MCR | MIN LOAD 36 % MCR | 100% MCR |
| NOx | lb/MBtu | 0.5 | 0.42 | 0.40 | 0.32 | 0.04 | 0.04 |
| CO | lb/MBtu | NA | NA | NA | NA | NA | NA |
| LOI | % | 5-10 | 5-10 | 3-5 | 3-5 | 2-4 | 2-4 |

4. DESIGN COAL & NATURAL GAS

Coal for all three units is Illinois Basin coal. The coal and natural gas properties are as follows.

Table 1-4 Current Coal Analysis

| COAL FUEL ANALYSIS (AS-RECEIVED) | | |
|---|---|---|
| | | COAL UNITS 1, 2, 3 AS RECEIVED |
| Higher Heating Value | [Btu/lb] | 13,220 |
| Carbon | % | 74.06 |
| Hydrogen | % | 4.88 |
| Sulfur | % | 0.65 |
| Nitrogen | % | 1.84 |
| Oxygen | % | 6.25 |
| Ash | % | 4.32 |
| Moisture | % | 8.00 |
| Total | % | 100.00 |

Table 1-5 Natural Gas Analysis

| GAS COMPOSITION (VOLUMETRIC/MOLAR PERCENTAGE BASIS) | | |
|---|---|---|
| Higher Heating Value | (Btu/lb) | 23,425 |
| Methane | % | 92.182 |
| Ethane | % | 6.770 |
| Propane | % | 0.400 |
| n-Butane (n-C4) | % | 0.044 |
| Iso-butane (i-C4) | % | 0.036 |
| Iso-pentane (i-C5) | % | 0.010 |
| n-Pentane (n-C5) | % | 0.006 |
| Carbon Dioxide | % | 0.177 |
| Nitrogen | % | 0.369 |
| Hexane | % | 0.009 |
| Total | % | 100.003 |

SECTION 1.6 PREDICTED PERFORMANCE

1. PREDICTED EMISSIONS

The predicted emission for each boiler is shown in the Table 6.

Table 1-6 Predicted Emissions with Natural Gas firing

| (PREDICTED AT THE AIR HEATER OUTLET) | UNIT 1 | UNIT 2 | UNIT 3 |
|---|---|---|---|
| Burners Only | | | |
| NOx, lbs/MBtu | 0.44 | 0.20 – 0.30 | 0.25 – 0.40 |
| CO, ppm @3% $O_2$, dry | ≦150 | ≦150 | ≦150 |
| Burners + SOFA | | | |
| NOx, lbs/MBtu | 0.25 | 0.06 – 0.10 | 0.08 – 0.12 |
| CO, ppm @3% $O_2$, dry | ≦150 | ≦150 | ≦150 |
| Burners + FGR | | | |
| NOx, lbs/MBtu | 0.16 | NA | NA |
| CO, ppm @3% $O_2$, dry | ≦150 | NA | NA |
| Burners + FGR + SOFA | | | |
| NOx, lbs/MBtu | 0.13 | NA | NA |
| CO, ppm @3% $O_2$, dry | ≦150 | NA | NA |

Note: Unit of lbs/MBtu is based on “Flue Gas dry 3% excess $O_2$; Assumes 270 $Nm^3$/GJ – ref IEA Paper 1986.

2. PREDICTED BOILER PERFORMANCE

Since there was no data and information about the boiler detail specification, the boiler detail design data, and the boiler current operation data, the required changes in the performance which is listed in the Table 1-2 cannot be stated in this proposal and the pricing for necessary equipment modifications shall be excluded in this proposal.

SECTION 1.7 GUARANTEES

The following performance items will be guaranteed at the boiler rated steam conditions.

- Economizer Outlet Flue Gas temperature
- Nitrogen oxide emissions
- CO emissions

Note: Since there is no detail data and operation data, Guarantee value will be informed later on.

SECTION 1.8 WARRANTY

1. Subject to the provisions hereinafter set forth, IHI undertakes to remedy, by making necessary repair or delivery replacement parts as its cost and expense, any defect in any part thereof which is due to defective material and/or poor workmanship on the parts of IHI, provided that such defect is discovered and notified to IHI within twelve (12) months after the date of completion works, whichever occurs first.

2. The Purchaser shall notify IHI in writing, as promptly as possible after discovery, of any defect for which claim is made under this warranty.

3. IHI shall not be liable for any other defects whatsoever in parts than the defects as specified in above paragraph 1, nor shall IHI in any circumstance be liable for any consequential damages, such as loss of time, product, earnings or profits directly or indirectly occasioned by reason of the defects as specified in above paragraph 1, or due to repair or replacement or other works done to the equipment to remedy such defect.

4. IHI shall not be liable for the defects arising out of;
   (1) Natural wear and tears, corrosion and erosion
   (2) Ill handling, negligence, improper operation and improper maintenance
   (3) Any change or modification of any or whole of parts on the part of the Purchaser.
   (4) Ill storage that is not in accordance with IHI's storage procedure

SECTION 1.9 SUB-SUPPLIER

The decision of sub-vendors and sub-manufacture for this project is made by IHI freely.
Such sub-manufacturer or sub-vendor will be selected from all parties of the world.

# CHAPTER 2. MODIFICATION OF COMBUSTION SYSTEM

## SECTION 2.1 COMBUSTION SYSTEM MODIFICATIONS APPROACH

1. GENERAL DESCRIPTION

In order to use natural gas instead of pulverized coal, the existing pulverized coal burner will be replaced with new natural gas burner which is a state of the art low NOx type burner.

The following Table 2-1 shows NOx Reduction Method required in RFQ.

Table 2-1 Required NOx reduction Method

| No. | DESCRIPTION |
|---|---|
| 1 | Natural Gas Low NOx Burners Only |
| 2 | Natural Gas Low NOx Burners + SOFA |
| 3 | Natural Gas Low NOx Burners + New FGR System |
| 4 | Natural Gas Low NOx Burners + FGR + SOFA |

Considering the existing equipment of each unit, the following NOx reduction cases are proposed in this proposal.

Table 2-2 Proposed NOx reduction Method for each Unit

| No. | DESCRIPTION | Unit 1 | Unit 2 | Unit 3 |
|---|---|---|---|---|
| 1 | Natural Gas Low NOx Burners Only | ○ | ○ | ○ |
| 2 | Natural Gas Low NOx Burners + SOFA | ○ | ○ | ○ |
| 3 | Natural Gas Low NOx Burners + New FGR System | ○ | NA | NA |
| 4 | Natural Gas Low NOx Burners + FGR + SOFA | ○ | NA | NA |

## 2. PROPOSED EQUIPMENT

Table 2-3 General Proposals

| | UNIT 1 | UNIT 2 | UNIT 3 |
|---|---|---|---|
| | 100% MCR | 100% MCR | 100% MCR |
| Low NOx Burners | 4 elevations | 3 elevations | 4 elevations |
| New Burners (number) | 16 total | 12 total | 16 total |
| Overfire Air System (if applicable) | New SOFA ports with 20% TCA | Re-use existing CCOFA &/or SOFA ports - if capable of 25% TCA and in good condition | Re-use existing CCOFA &/or SOFA ports - if capable of 25% TCA and in good condition |
| Number of ports | 4 total | 2 | 4 |
| Igniter Equipment | | | |
| Number provided | 16 total | 12 total | 16 total |
| Type | Class 1 | Class 1 | Class 1 |
| Rated Capacity | 6.0 mmBTU/hr | 12.0 mmBTU/hr | 25.0 mmBTU/hr |
| Flame Scanner Equipment | | | |
| Number provided | 16 total | 12 total | 16 total |
| Type | Direct-sighted Spectrum VIR VI Tri-Colour (VIS/IR/UV) scanner system | Flexible fiber-optic Spectrum VIR VI Tri-Colour (VIS/IR/UV) scanner system | Flexible fiber-optic Spectrum VIR VI Tri-Colour (VIS/IR/UV) scanner system |

## 3. PROPOSED SYSTEM DESCRIPTION

### (1) Natural Gas Low NOx Burner

a. Unit 1

To convert Units 1 to 100% natural gas firing, we are recommending the following modifications to the main windboxes.

IHI strategy will be to modify the existing coal compartments for natural gas firing. Since coal firing is being removed including burner air register is installed. Old oil igniters are also removed.

- Four (4) elevations of gas firing are planned for Unit 1, with 6 multi spuds gas nozzles.

The new firing compartments will have gas nozzle spuds with fully assembled in factory. Our new gas burner assembly is leak tested before shipment.

(a) New gas spuds will be designed on a gas existing pressure of 0.25 MPa.

(b) System will be capable of approximately 5:1 turndown. Minimum recommended gas pressure is 0.8 MPa above furnace pressure.

(c) The flame scanners are upgrading to FPS scanners' without fiber optics.

(d) Coal firing equipment will be removed and insulated front panels will be provided to plug the coal nozzle opening while also making provisions for the gas penetration.

Fig 2-1 Gas Burner Assembly

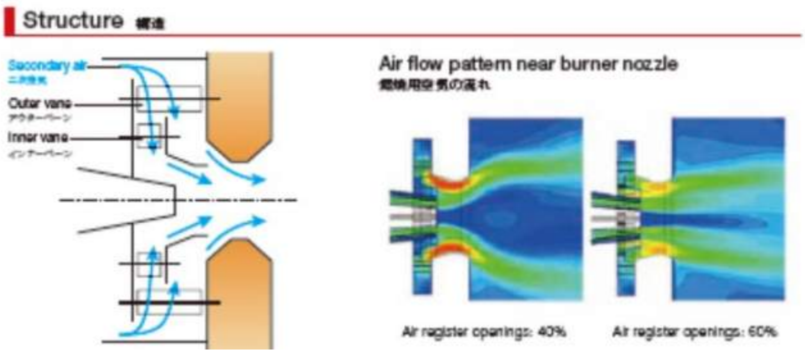
Fig 2-2 Gas Spuds

The spud nozzle is fixed with tip section. The spud nozzle is made with cast iron with No welding section as shows. This spud nozzle minimize the any damage from heat radiation from the furnaces and realize the long life.

Fig 2-3 Old design: Welding type

Fig 2-4 IHI design: Mold type

Existing air register will be removed if installed, and IHI design new air register will be installed.
IHI design air register has good flame stability with vane position as follows.



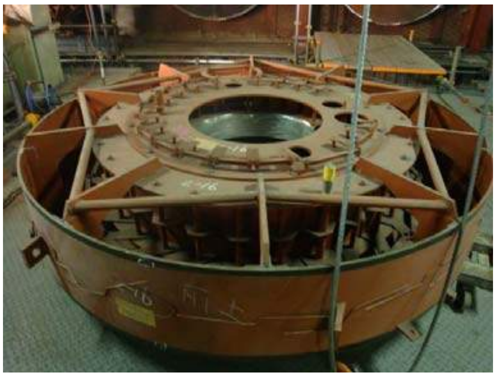



Fig 2-5 Air register Assembly supply

Fig 2-6 Installation

b. Unit 2 and Unit 3

To convert Units 2 and 3 to 100% natural gas firing, we are recommending the following modifications to the main windboxes.

R-V's strategy will be to modify the existing coal compartments for natural gas firing. Since coal firing is being removed, this strategy will reduce the required outage time by minimizing main windbox modifications. This strategy will also reduce the pressure part modifications by being able to reuse the existing side horn igniter openings. The coal elevations that will be utilized are to be determined after a windbox model has been finalized and optimized with R-V's proprietary combustion modeling software.

- Three (3) elevations of gas firing are planned for Unit 2, with two (2) tilting gas nozzle tips and two (2) fixed gas spuds per compartment.
- Four (4) elevations of gas firing are planned for Unit 3, with (4) tilting gas nozzle tips and four (4) fixed gas spuds per compartment.

The new gas firing compartments will have gas nozzle tips that are internally connected, enabling the nozzles to tilt in unison with a single horizontal adjusting link. Fig 2-7 shows an example of the proposed nozzle tip arrangement to be utilized at "Confidential Client's" Units #2 & #3. The gas nozzle tips will be R-V's Thermal Guard™ Series I design. All tips will be fabricated from 309 SS material (upgrade to RA 253 MA is available or if it is required based on past experience). The expected service life of R-V Thermal Guard™ Series tips will exceed the service life of the current tilting nozzle tips.

The fixed gas spuds are internally connected to a common local supply manifold, having a single inlet flange exiting the windboxes at the front panel where the coal piping is currently. Our new supplied gas piping is hydrostatically pressure tested at 75 psi before shipment. This testing and rigid design eliminates the possibility of the gas piping from leaking inside of the windbox; when compared to a flexible hose type design gas burner arrangement.

The fixed gas spuds are internally connected to a common local supply manifold, having a single inlet flange exiting the windboxes at the front panel where the coal piping is currently. The supplied burner gas piping will be hydrostatically pressure tested at 75 psi prior to shipment. This testing and rigid design eliminates the possibility of the gas piping from leaking inside of the windbox; when compared to a flexible hose type design gas burner arrangement.

(a) New gas spuds will be designed based on a gas exit pressure of 22 psig.

(b) System will be capable of approximately 6:1 turndown. Minimum recommended gas pressure is 0.5 psig above furnace pressure.

(c) Provisions for gas flame scanners will be incorporated in the new burner nozzles.

(d) All coal firing equipment is to be removed by others. Insulated front panels will be provided to plug the coal nozzle openings while also making provisions for the gas piping penetration.

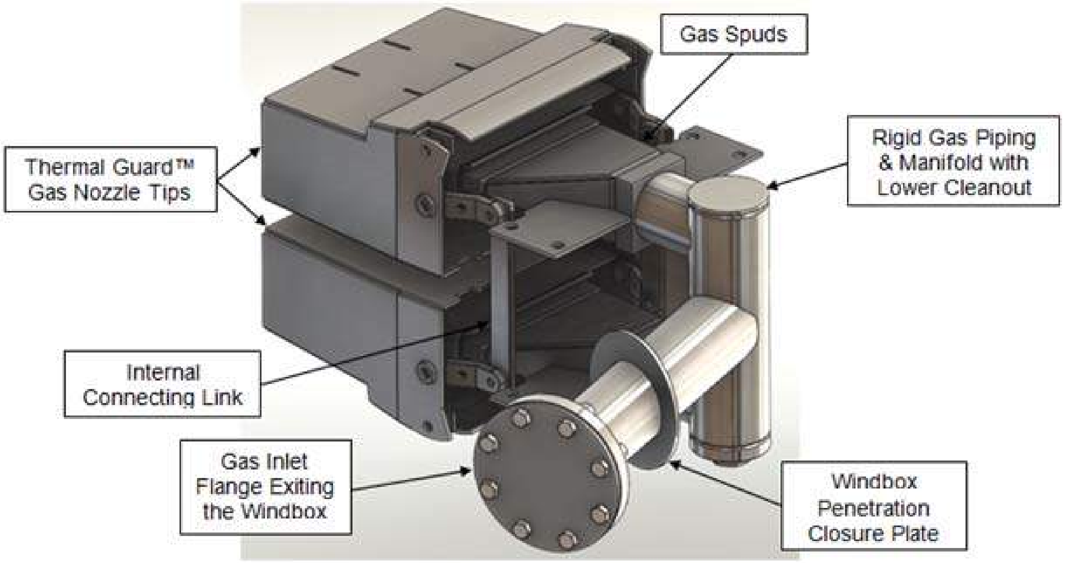



*Fig 2-7 Typical fixed two (2) gas spud arrangement with manifold assembly shown with two (2) tilting gas nozzle tips – similar to proposed equipment for Unit 2 (R-V's Thermal Gurad™ Series I design)*

The existing auxiliary air, CCOFA and/or SOFA nozzle tips will not be changed if they provide the required air flow velocities and are in good condition. If replacements are required, upgraded Thermal Guard™ replacements tips are recommended for longer service life compared to the OEM design.

Upon award, operating data will be taken and the new Thermal Guard™ nozzle tips will be sized for proper air flow distribution and operating velocities. R-V's design standards, which are based on experience with different sized furnaces and fuel types, dictate the optimal settings for these design parameters. We will use our proprietary tangential firing system design software to optimize "Confidential Client's" Units 2 and 3 for low NOx natural gas firing.

**Secondary Air Modifications**

The operating data will also be used to review current damper operation for applying and sizing our damper venturi plates. Initial calculations show that the existing windbox arrangement is oversized for low NOx gas firing; which, if not addressed, will result in low mixing velocities, poor or non- existent air biasing control and high CO emissions.

Based on experience, we anticipate that all main windbox compartments will require the installation of venturi inserts.

The new venturi inserts will be sized using our windbox design modeling results to increase damper control throughout a greater load range. Better damper operational control is accomplished by decreasing the amount of open damper air flow area with an aerodynamic plate(s) inserted in the damper zone. Nearly 200 tangential fired units are operating with these damper venture upgrades.

Installing damper venturi greatly increases damper control over the load range, thereby improving air biasing capability, improving air flow distribution throughout the height of each windbox and also improving air flow distribution to each corner.

By installing venturi in all main windbox compartments, we further ensure that we divert enough of the main firing zone combustion air to the SOFA compartments. This will enable us to achieve low NOx gas firing, while maintaining sufficient airflow to the fuel compartments for efficient combustion.

The existing auxiliary air, CCOFA and/or SOFA nozzle tips will not be changed if they provide the required air flow velocities and are in good condition. If replacements are required, upgraded Thermal Guard™ replacements tips are recommended for longer service life compared to the OEM design.

Upon award, operating data will be taken and the new Thermal Guard™ nozzle tips will be sized for proper air flow distribution and operating velocities. R-V's design standards, which are based on experience with different sized furnaces and fuel types, dictate the optimal settings for these design parameters. We will use our proprietary tangential firing system design software to optimize "Confidential Client's" Units 2 and 3 for low NOx natural gas firing.

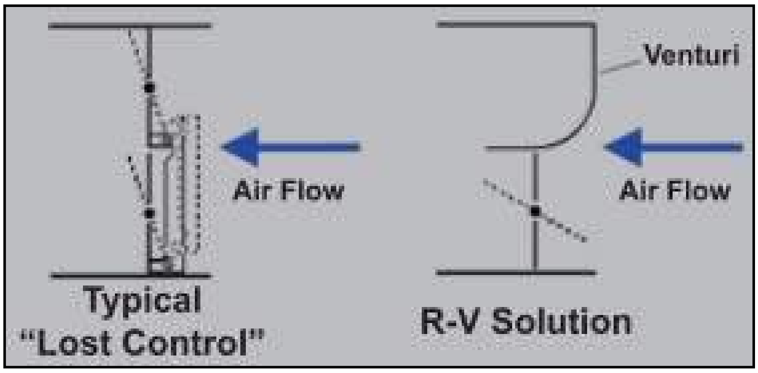



Fig 2-8: Solution to regain damper blade control by installing a venturi

Figure 2-8 shows the difference between a typical damper arrangement and an arrangement with a venturi. The damper area with the venturi is decreased in order to provide considerably greater air control as compared to the present dampers.

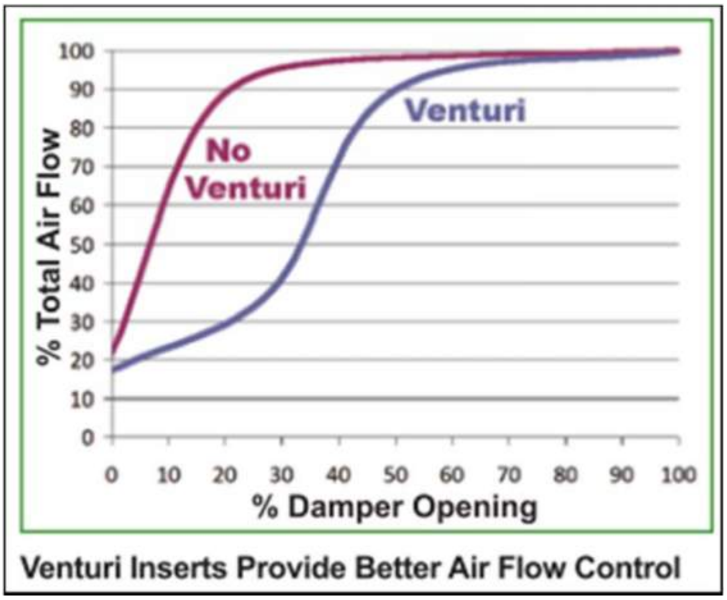



Fig 2-9: Typical damper blade control gain when installing a venturi

Fig 2-9 shows the relationship between the % damper opening position compared to the amount of total air flow with and without venturi. These curves demonstrate that dampers with venturi operate in a more open position over a wider control range.

(2) Natural Gas Valve Train Equipment

Natural Gas Valve Train Equipment consists of the followings.

a. For Unit 1

| NATURAL GAS INLET PRESSURE REDUCING STATION: | 1 set |
|---|---|
| a) One (1) 300# FPS Inlet Manual Ball Valve<br>b) One (1) Y strainer<br>c) One (1) Electric Gas Heater c/w Control Panel with:<br>• Two (2) 300# FPS Isolation Valves<br>d) One (1) Fisher 300# flanged PRV. (Worker)<br>e) One (1) Fisher 300# flanged PRV with slam shut over pressure protection and manual reset. (Monitor)<br>f) One (1) Fisher 300# flanged PRV. (Token Relief)<br>g) One (1) ABZ 150#, Butterfly Valve (Outlet)<br>h) Two (2) Yokogawa Pressure Transmitters<br>i) One (1) Yokogawa Temperature Transmitter<br>j) Two (2) Ashcroft Pressure Gauges c/w root valves<br>k) One (1) NEMA 4 Stainless Steel junction box with field terminals for valve rack electrical connections. Wiring from valve rack components to junction box will be factory installed by FPS<br>l) Complete functional and pressure tests prior to shipping | |
| MAIN GAS HEADER: | 1 set |
| a) One (1) ABZ Manual Butterfly Inlet Isolation Valve<br>b) One (1) Y-Strainer<br>c) Three (3) Ashcroft Pressure Gauges w/ Isolation Valves<br>d) Three (3) Yokogawa Pressure Transmitter w/ Block & Bleed Isolation Manifold<br>e) One (1) McCrometer V-Cone Flowmeter w/<br>• One (1) High Flow Yokogawa Multi-variable Transmitter<br>• One (1) Low Flow Yokogawa Multi-variable Transmitter<br>f) One (1) ABZ Automatic Butterfly Safety Shutoff Valve<br>g) One (1) Fisher Flow Control Valve<br>h) One (1) Fisher Start-up Regulator w/<br>• Two (2) FPS #150 Manual Isolation Ball Valves<br>i) One (1) ABZ Manual Butterfly Outlet Isolation Valve<br>j) Pressure taps as required for NFPA pressure testing requirements.<br>k) Instrument Air Filter Regulator and Isolation Valve | |
| MAIN GAS HEADER VENT SPOOL: | 1 set |
| a) One (1) 150# FPS Automatic Safety Vent Valve.<br>b) Spool piping with test point isolation valve as required for NFPA pressure testing requirements.<br>c) One (1) 150# FPS Manual Vent Valve w/ Limit Switch (for manual leak testing of SVV)<br>d) Instrument Air Filter Regulator and Isolation Valve | |
| IGNITER GAS HEADER: | 1 set |
| a) One (1) 150# FPS Manual Inlet Isolation Ball Valve<br>b) One (1) Y-Strainer<br>c) Two (2) Ashcroft Pressure Gauges w/ Isolation Valves<br>d) One (1) Yokogawa Pressure Transmitter w/ Block & Bleed Isolation Manifold<br>e) One (1) McCrometer V-Cone Flowmeter w/<br>• One (1) Yokogawa Multi-variable Transmitter<br>f) One (1) 150# FPS Automatic Safety Shutoff Ball Valve<br>g) One (1) Fisher Ignitor Regulator<br>h) One (1) 150# FPS Manual Outlet Isolation Ball Valve | |

i) Pressure taps as required for NFPA pressure testing requirements.
j) Instrument Air Filter Regulator and Isolation Valve

| IGNITER GAS HEADER VENT SPOOL: | 1 set |
|---|---|
| a) One (1) 150# FPS Automatic Safety Vent Valve.<br>b) Spool piping with test point isolation valve as required for NFPA pressure testing requirements.<br>c) One (1) 150# FPS Manual Vent Valve w/ Limit Switch (for manual leak testing of SVV)<br>d) Instrument Air Filter Regulator and Isolation Valve | |

| LOCAL BURNER/IGNITER VALVE TRAINS: | 16 set |
|---|---|
| **Burner Section**<br>a) Two (2) 150# FPS Manual Burner Ball Valves<br>b) Two (2) 150# FPS Automatic Burner Safety Shutoff Valves<br>c) One (1) Socketweld FPS Automatic Burner Safety Vent Valves<br>d) One (1) Socketweld FPS Manual Burner Vent Valve w/ Limit Switch (for auto vent valve leak testing).<br>e) One (1) Ashcroft pressure gauge (including isolation valve).<br><br>**Igniter Section**<br>a) Two (2) Socketweld FPS Manual Ignitor Ball Valves<br>b) Two (2) Socketweld FPS Automatic Ignitor Safety Shutoff Valves<br>c) One (1) Socketweld FPS Automatic Burner Safety Vent Valves<br>d) One (1) Socketweld FPS Manual Burner Vent Valve w/ Limit Switch (for auto vent valve leak testing).<br>e) One (1) Ashcroft pressure gauge (including isolation valve). | |

b. For Unit 2

| NATURAL GAS INLET PRESSURE REDUCING STATION: | 1 set |
|---|---|
| a) One (1) 300# FPS Inlet Manual Ball Valve<br>b) One (1) Y strainer<br>c) One (1) Electric Gas Heater c/w Control Panel with:<br>• Two (2) 300# FPS Isolation Valves<br>d) One (1) Fisher 300# flanged PRV. (Worker)<br>e) One (1) Fisher 300# flanged PRV with slam shut over pressure protection and manual reset. (Monitor)<br>f) One (1) Fisher 300# flanged PRV. (Token Relief)<br>g) One (1) ABZ 150#, Butterfly Valve (Outlet)<br>h) Two (2) Yokogawa Pressure Transmitters<br>i) One (1) Yokogawa Temperature Transmitter<br>j) Two (2) Ashcroft Pressure Gauges c/w root valves<br>k) One (1) NEMA 4 Stainless Steel junction box with field terminals for valve rack electrical connections. Wiring from valve rack components to junction box will be factory installed by FPS<br>l) Complete functional and pressure tests prior to shipping | |

| MAIN GAS HEADER: | 1 set |
|---|---|
| a) One (1) ABZ Manual Butterfly Inlet Isolation Valve<br>b) One (1) Y-Strainer<br>c) Three (3) Ashcroft Pressure Gauges w/ Isolation Valves<br>d) Three (3) Yokogawa Pressure Transmitter w/ Block & Bleed Isolation Manifold<br>e) One (1) McCrometer V-Cone Flowmeter w/<br>• One (1) High Flow Yokogawa Multi-variable Transmitter<br>• One (1) Low Flow Yokogawa Multi-variable Transmitter<br>f) One (1) ABZ Automatic Butterfly Safety Shutoff Valve | |

g) One (1) Fisher Flow Control Valve
h) One (1) Fisher Start-up Regulator w/
- Two (2) FPS #150 Manual Isolation Ball Valves

i) One (1) ABZ Manual Butterfly Outlet Isolation Valve
j) Pressure taps as required for NFPA pressure testing requirements.
k) Instrument Air Filter Regulator and Isolation Valve

MAIN GAS HEADER VENT SPOOL: 1 set

a) One (1) 150# FPS Automatic Safety Vent Valve.
b) Spool piping with test point isolation valve as required for NFPA pressure testing requirements.
c) One (1) 150# FPS Manual Vent Valve w/ Limit Switch (for manual leak testing of SVV)
d) Instrument Air Filter Regulator and Isolation Valve

IGNITER GAS HEADER: 1 set

a) One (1) 150# FPS Manual Inlet Isolation Ball Valve
b) One (1) Y-Strainer
c) Two (2) Ashcroft Pressure Gauges w/ Isolation Valves
d) One (1) Yokogawa Pressure Transmitter w/ Block & Bleed Isolation Manifold
e) One (1) McCrometer V-Cone Flowmeter w/
- One (1) Yokogawa Multi-variable Transmitter

f) One (1) 150# FPS Automatic Safety Shutoff Ball Valve
g) One (1) Fisher Ignitor Regulator
h) One (1) 150# FPS Manual Outlet Isolation Ball Valve
i) Pressure taps as required for NFPA pressure testing requirements.
j) Instrument Air Filter Regulator and Isolation Valve

IGNITER GAS HEADER VENT SPOOL: 1 set

a) One (1) 150# FPS Automatic Safety Vent Valve.
b) Spool piping with test point isolation valve as required for NFPA pressure testing requirements.
c) One (1) 150# FPS Manual Vent Valve w/ Limit Switch (for manual leak testing of SVV)
d) Instrument Air Filter Regulator and Isolation Valve

LOCAL BURNER/IGNITER VALVE TRAINS: 12 set

**Burner Section**

a) Two (2) 150# FPS Manual Burner Ball Valves
b) Two (2) 150# FPS Automatic Burner Safety Shutoff Valves
c) One (1) Socketweld FPS Automatic Burner Safety Vent Valves
d) One (1) Socketweld FPS Manual Burner Vent Valve w/ Limit Switch (for auto vent valve leak testing).
e) One (1) Ashcroft pressure gauge (including isolation valve).

**Igniter Section**

a) Two (2) Socketweld FPS Manual Ignitor Ball Valves
b) Two (2) Socketweld FPS Automatic Ignitor Safety Shutoff Valves
c) One (1) Socketweld FPS Automatic Burner Safety Vent Valves
d) One (1) Socketweld FPS Manual Burner Vent Valve w/ Limit Switch (for auto vent valve leak testing).
e) One (1) Ashcroft pressure gauge (including isolation valve).

c. For Unit 3

| NATURAL GAS INLET PRESSURE REDUCING STATION: | 1 set |
|---|---|
| a) One (1) 300# FPS Inlet Manual Ball Valve<br>b) One (1) Y strainer<br>c) One (1) Electric Gas Heater c/w Control Panel with:<br>• Two (2) 300# FPS Isolation Valves<br>d) One (1) Fisher 300# flanged PRV. (Worker)<br>e) One (1) Fisher 300# flanged PRV with slam shut over pressure protection and manual reset. (Monitor)<br>f) One (1) Fisher 300# flanged PRV. (Token Relief)<br>g) One (1) ABZ 150#, Butterfly Valve (Outlet)<br>h) Two (2) Yokogawa Pressure Transmitters<br>i) One (1) Yokogawa Temperature Transmitter<br>j) Two (2) Ashcroft Pressure Gauges c/w root valves<br>k) One (1) NEMA 4 Stainless Steel junction box with field terminals for valve rack electrical connections. Wiring from valve rack components to junction box will be factory installed by FPS<br>l) Complete functional and pressure tests prior to shipping | |
| ELEVATION GAS HEADERS: | 4 sets |
| a) One (1) ABZ Manual Butterfly Inlet Isolation Valve<br>b) One (1) Y-Strainer<br>c) Three (3) Ashcroft Pressure Gauges w/ Isolation Valves<br>d) Three (3) Yokogawa Pressure Transmitter w/ Block & Bleed Isolation Manifold<br>e) One (1) McCrometer V-Cone Flowmeter w/<br>• One (1) High Flow Yokogawa Multi-variable Transmitter<br>• One (1) Low Flow Yokogawa Multi-variable Transmitter<br>f) One (1) ABZ Automatic Butterfly Safety Shutoff Valve<br>g) One (1) Fisher Flow Control Valve<br>h) One (1) Fisher Start-up Regulator w/<br>• Two (2) FPS #150 Manual Isolation Ball Valves<br>i) One (1) ABZ Manual Butterfly Outlet Isolation Valve<br>j) Pressure taps as required for NFPA pressure testing requirements.<br>k) Instrument Air Filter Regulator and Isolation Valve | |
| ELEVATION GAS HEADER VENT SPOOL: | 4 sets |
| a) One (1) 150# FPS Automatic Safety Vent Valve.<br>b) Spool piping with test point isolation valve as required for NFPA pressure testing requirements.<br>c) One (1) 150# FPS Manual Vent Valve w/ Limit Switch (for manual leak testing of SVV)<br>d) Instrument Air Filter Regulator and Isolation Valve | |
| IGNITER GAS HEADER: | 1 set |
| a) One (1) 150# FPS Manual Inlet Isolation Ball Valve<br>b) One (1) Y-Strainer<br>c) Two (2) Ashcroft Pressure Gauges w/ Isolation Valves<br>d) One (1) Yokogawa Pressure Transmitter w/ Block & Bleed Isolation Manifold<br>e) One (1) McCrometer V-Cone Flowmeter w/<br>• One (1) Yokogawa Multi-variable Transmitter<br>f) One (1) 150# FPS Automatic Safety Shutoff Ball Valve<br>g) One (1) Fisher Ignitor Regulator<br>h) One (1) 150# FPS Manual Outlet Isolation Ball Valve<br>i) Pressure taps as required for NFPA pressure testing requirements.<br>j) Instrument Air Filter Regulator and Isolation Valve | |

| IGNITER GAS HEADER VENT SPOOL: | 1 set |
|---|---|
| a) One (1) 150# FPS Automatic Safety Vent Valve.<br>b) Spool piping with test point isolation valve as required for NFPA pressure testing requirements.<br>c) One (1) 150# FPS Manual Vent Valve w/ Limit Switch (for manual leak testing of SVV)<br>d) Instrument Air Filter Regulator and Isolation Valve | |
| LOCAL BURNER/IGNITER VALVE TRAINS: | 16 sets |
| **<u>Burner Section</u>**<br>a) Two (2) 150# FPS Manual Burner Ball Valves<br>b) Two (2) 150# FPS Automatic Burner Safety Shutoff Valves<br>c) One (1) Socketweld FPS Automatic Burner Safety Vent Valves<br>d) One (1) Socketweld FPS Manual Burner Vent Valve w/ Limit Switch (for auto vent valve leak testing).<br>e) One (1) Ashcroft pressure gauge (including isolation valve).<br><br>**<u>Igniter Section</u>**<br>a) Two (2) Socketweld FPS Manual Ignitor Ball Valves<br>b) Two (2) Socketweld FPS Automatic Ignitor Safety Shutoff Valves<br>c) One (1) Socketweld FPS Automatic Burner Safety Vent Valves<br>d) One (1) Socketweld FPS Manual Burner Vent Valve w/ Limit Switch (for auto vent valve leak testing).<br>e) One (1) Ashcroft pressure gauge (including isolation valve). | |

(3) New FGR System

a. Unit 1

Since there is no information and data about the existing FD fan and ID fan specification and the description of Air and Flue Gas system, forced FGR system is applied.

The forced FGR system consists of new flue gas duct from economizer outlet to GAH outlet secondary air duct and new GI Fan (Flue Gas Injection Fan).

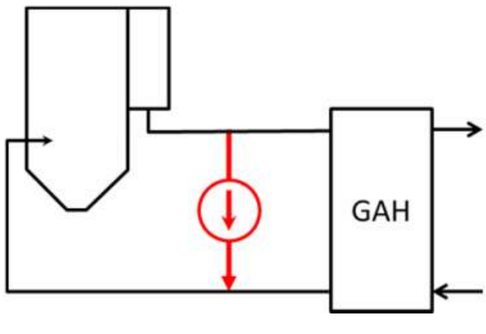



Fig. 2-10 New forced FGR system

b. Unit 2 and Unit 3

Not required on Unit 2 and 3.

(4) New OFA System

a. Unit 1

Since there is no existing OFA System, new OFA system will be installed.

New four (4) OFA port assemblies will be installed at the above of the top burner level on the furnace front wall. The bias air will be fed from the top of the common wind box.

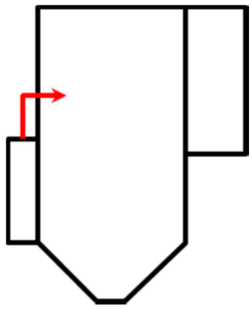


Fig 2-11 SOFA System

b. Unit 2 and Unit 3

Since the existing separated OFA (SOFA) and/or close-coupled OFA (CCOFA) systems will be reused, if they are in good and serviceable working condition, new OFA system is not required for Unit 2 and Unit 3.

4. LIST OF EXPERIENCE, EMPHASIZING CASES WITH UNITS OF SIMILAR CHARACTERISTICS

(1) Experience of Fuel Conversion

Table 2-4 IHI Experience List for Fuel Conversion

| No. | Unit | Location | Capacity | Year | Remarks |
|---|---|---|---|---|---|
| 1 | Incheon P.S. 1B | Korea | 250 MW | 1987 | Oil Firing to Gas firing |
| 2 | Incheon P.S. 2B | Korea | 250 MW | 1987 | Oil Firing to Gas firing |
| 3 | Seoul P.S. 4B | Korea | 426 t/h | 1981 | Coal & Oil Firing to Gas firing |
| 4 | Gresick P.S. 3B | Indonesia | 200 MW | 1991 | Oil Firing to Gas firing |
| 5 | Gresick P.S. 4B | Indonesia | 200 MW | 1991 | Oil Firing to Gas firing |
| 6 | Kawasaki 1B | Japan | 175 MW | 1982 | Coal Firing to Gas firing |
| 7 | Kawasaki 3B | Japan | 175 MW | 1983 | Coal Firing to Gas firing |
| 8 | Himeji 5B | Japan | 156 MW | 1986 | Coal Firing to Gas firing |
| 9 | Yokohama 2B | Japan | 175 MW | 1983 | Oil Firing to Gas firing |
| 10 | Yokohama 4B | Japan | 175 MW | 1981 | Oil Firing to Gas firing |
| 11 | Yokohama 5B | Japan | 175 MW | 1985 | Oil Firing to Gas firing |
| 12 | Yokohama 6B | Japan | 175 MW | 1983 | Oil Firing to Gas firing |
| 13 | Sakaiko 3B | Japan | 250 MW | 1980 | Oil Firing to Gas firing |
| 14 | Sakaiko 8B | Japan | 250 MW | 1981 | Oil Firing to Gas firing |
| 15 | Anesaki 8B | Japan | 600 MW | 1971 | Oil Firing to Gas firing |
| 16 | Kashima 2B | Japan | 600 MW | 1973 | Oil Firing to Gas firing |

Table 2-5 List of gas firing equipment that has been supplied by R-V industries since 1990

| Year | Description | End User |
|---|---|---|
| 1991 | (96) Air Nozzle Tips<br>(160) Gas Nozzle Tips<br>(40) Oil Nozzle Tips<br>(160) Gas Spuds | Central Hudson, Roseton Station #1 & #2 |
| 1994 | (48) Gas Nozzle Tips<br>(48) Gas Spuds<br>(48) Gas Piping Assemblies | Low $NO_X$ Gas Conversion for Vermillion #1 & #2 |
| 1998 | (16) Oil Nozzle Tips<br>(8) Pilot Torch Nozzles<br>(16) Gas Spuds | Consumer’s Energy, B.C. Cobb Plant |
| 1998 | (17) Gas Nozzle Tips<br>(9) Oil Nozzle Tips<br>(28) Air Nozzle Tips | Beloit Corporation, Hattiesburg, MS |
| 1999 | (12) Pilot Torch Nozzles | Utilicorp, Great Bend, KS |
| 1999 | (16) Pilot Torch Nozzles<br>(32) Gas Nozzle Tips<br>(16) Oil Nozzle Tips<br>(48) Air Nozzle Tips<br>(32) Gas Spuds | Consumer’s Energy, B.C. Cobb Plant |
| 2001 | (8) Oil Nozzle Tips<br>(16) Gas Nozzle Tips | Florida Crystals Corp, South Bay, FL |
| 2002 | (80) Gas Spuds<br>(80) Gas Nozzle Tips<br>(40) Oil Nozzle Tips<br>(32) Air Nozzle Tips | Dominion Energy, Possum Point, VA |
| 2003 | (8) Air Nozzle Tips | Dominion Energy, Possum Point, VA |
| 2012 | (24) Gas Nozzle Tips<br>(24) Gas Spuds<br>(12) Gas Piping Assemblies<br>(4) Oil Nozzle Tips<br>(16) Coal Nozzle Tips<br>(12) Air Nozzle Tips<br>(4) SOFA Assemblies | Low $NO_X$ Gas Addition for Hastings Utilities, Whelan Energy Center Unit #1 |
| 2014 | (16) Gas Nozzle Tips<br>(16) Gas Spuds<br>(16) Gas Piping Assemblies | Low $NO_X$ Gas Addition for SAPPI Fine Paper North America, Somerset Mill - Hog Fuel Boiler #2 |
| 2015 | (16) Gas Nozzle Tips<br>(16) Gas Spuds<br>(8) Gas Piping Assemblies | Low NOx Gas Addition for International Paper, Prattville Mill – Power Boiler #2 |
| 2016 | (16) Gas Nozzle Tips<br>(16) Gas Spuds<br>(8) Gas Piping Assemblies | Low NOx Gas Addition for WestRock, Fernandina Beach Mill – BMACT #7 |
| 2016 | (16) Gas Nozzle Tips<br>(16) Gas Spuds<br>(8) Gas Piping Assemblies | Low NOx Gas Conversion for International Paper, Eastover Mill – Power Boiler #1 |
| 2016 | (24) Gas Nozzle Tips<br>(24) Gas Spuds<br>(12) Gas Piping Assemblies | Low NOx Gas Conversion for Greenidge Generation, LLC. Unit #6 |
| 2017 | (80) Gas Nozzle Tips<br>(80) Gas Spuds<br>(40) Gas Piping Assemblies | Pending: NRG’s Dunkirk Units #2, #3 & #4 |

SECTION 2.2 SCOPE OF WORK

1. General description of Scope of work

The work to be performed by IHI consists of design, manufacture, and procurement.

In case the parts and/or material specified below become shorten during the site work period due to the customer's reason such as miss welding, missing, extreme usage, etc., IHI will supply the required parts and/or material as the additional order.

The following items are included in our proposal.

Table 2-6 Scope of Supply

| | INCLUDED YES OR NO | | |
|---|---|---|---|
| | UNIT 1 | UNIT 2 | UNIT 3 |
| CFD Modeling | IHI and R-V uses their proprietary computer modeling software programs instead of CFD to design and optimize every new low NOx windbox arrangement. NOTE: CFD is only used by IHI and R-V if severe secondary duct air flow misdistribution exists.<br>While not included with this proposal, an optional Boiler Performance Analysis Study is also available if desired by client to generate a detailed technical evaluation of the thermodynamic performance before and after the firing conversion. | | |
| Burner Replacement | Yes | Yes | Yes |
| Secondary air modifications | Yes | Yes | Yes |
| Igniters | Yes | Yes | Yes |
| Scanners | Yes | Yes | Yes |
| SOFA System | Yes | No<br>(Re-use) | No<br>(Re-use) |
| FGR System | Yes | No | No |
| Logic diagrams | Yes | Yes | Yes |
| I/O List | Yes | Yes | Yes |
| System Operating Description | Yes | Yes | Yes |
| Pressure Reducing and Metering Skids (3) | Yes | Yes | Yes |
| Burner Control Piping Skids (3) | Yes | Yes | Yes |
| Field Service Included | Yes | Yes | Yes |
| Number of man days | 40 | 64 | 64 |
| Number of round trips | 4 | 7 | 7 |

2. Scope of Service

(1) Engineering
  a. Confirm retrofit requirements through the analysis of operational and modifications history.
  b. Conceptual and detailed engineering
  c. Use our proprietary computer modeling software programs instead of CFD to design and optimize every new low NOx windbox arrangement.
  d. Confirm the optimum performance that can be achieved given the existing furnace geometry and burner separation.
  e. Instrumentation and controls
  f. Logic diagrams to allow Integration of new equipment into existing systems
  g. I/O list
  h. System operating description

(2) Equipment and Materials:
  a. Burners nozzle components
  b. Complete natural gas supply system piping skids
    (a) Pressure reduction and metering skid – one (1) per Unit (assume inlet pressure of 600 psig)
    (b) Burner control piping skid – as required for each unit
  c. SOFA ports and ductwork, if applicable.
  d. Air registers, dampers and actuators
  e. FGR system, as required
  f. Instruments and controls
  g. Windbox modifications for NG piping
  h. Burner connections and fittings for NG piping
  i. Flow correction devices

(3) Fabrication

(4) Technical Advisory Service for installation, start up and commissioning

(5) Tuning of the burner system as required

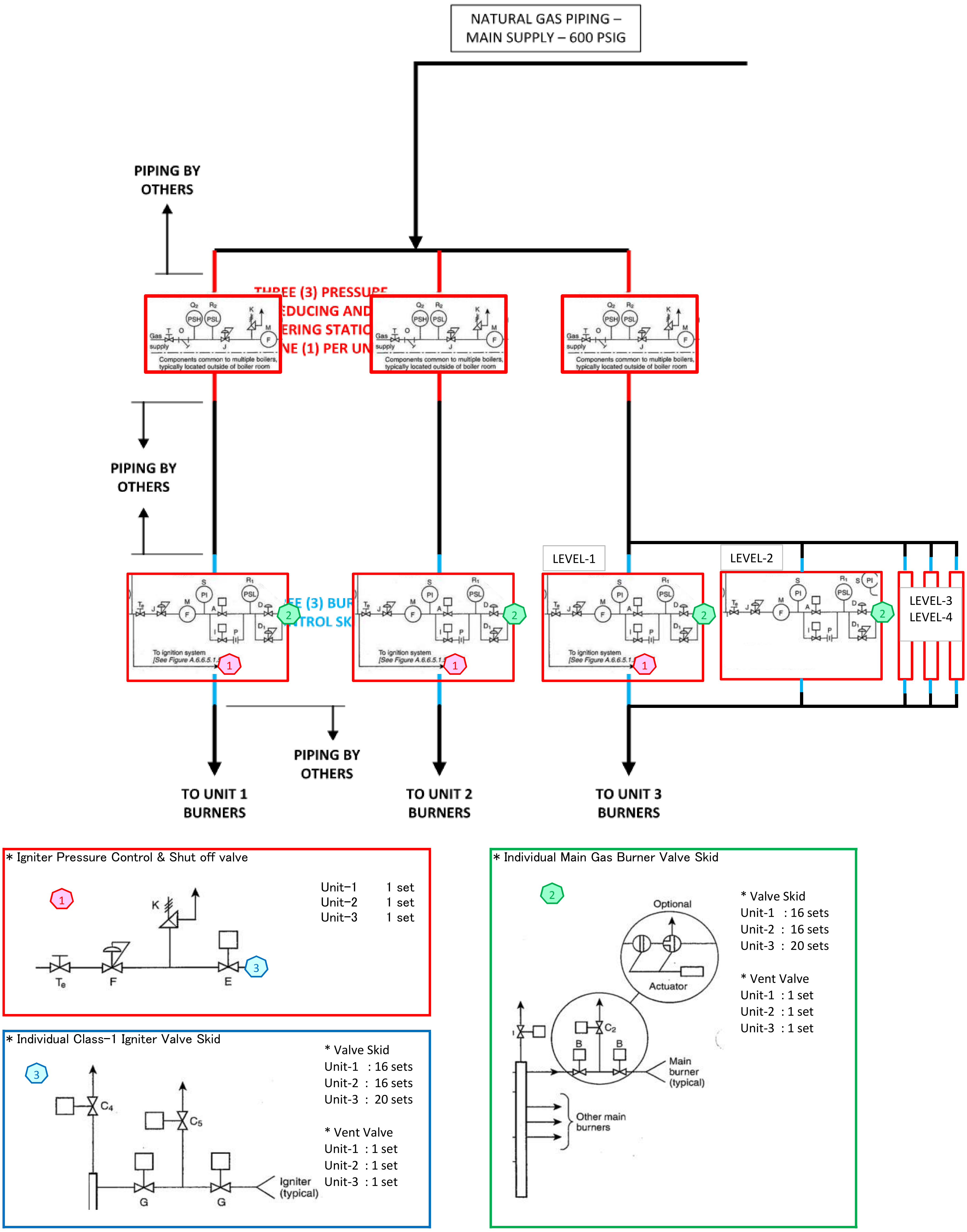
SECTION 2.3 OUT OF SCOPE

The following items, which are not specified in SECTION 2.3, are not included in IHI scope of supply.

**1)** Site Works
**2)** Transportation from work shop to power station
**3)** Items other than CHAPTER 2, SECTION 2.2 “SCOPE OF WORK”

SECTION 2.4 ATTACHMENT

ATTACHMENT 1: SIMPLIFIED P&ID
ATTACHMENT 2: EXPECTED SCHEDULE
ATTACHMENT 3: DIVISION OF RESPONSIBILITY

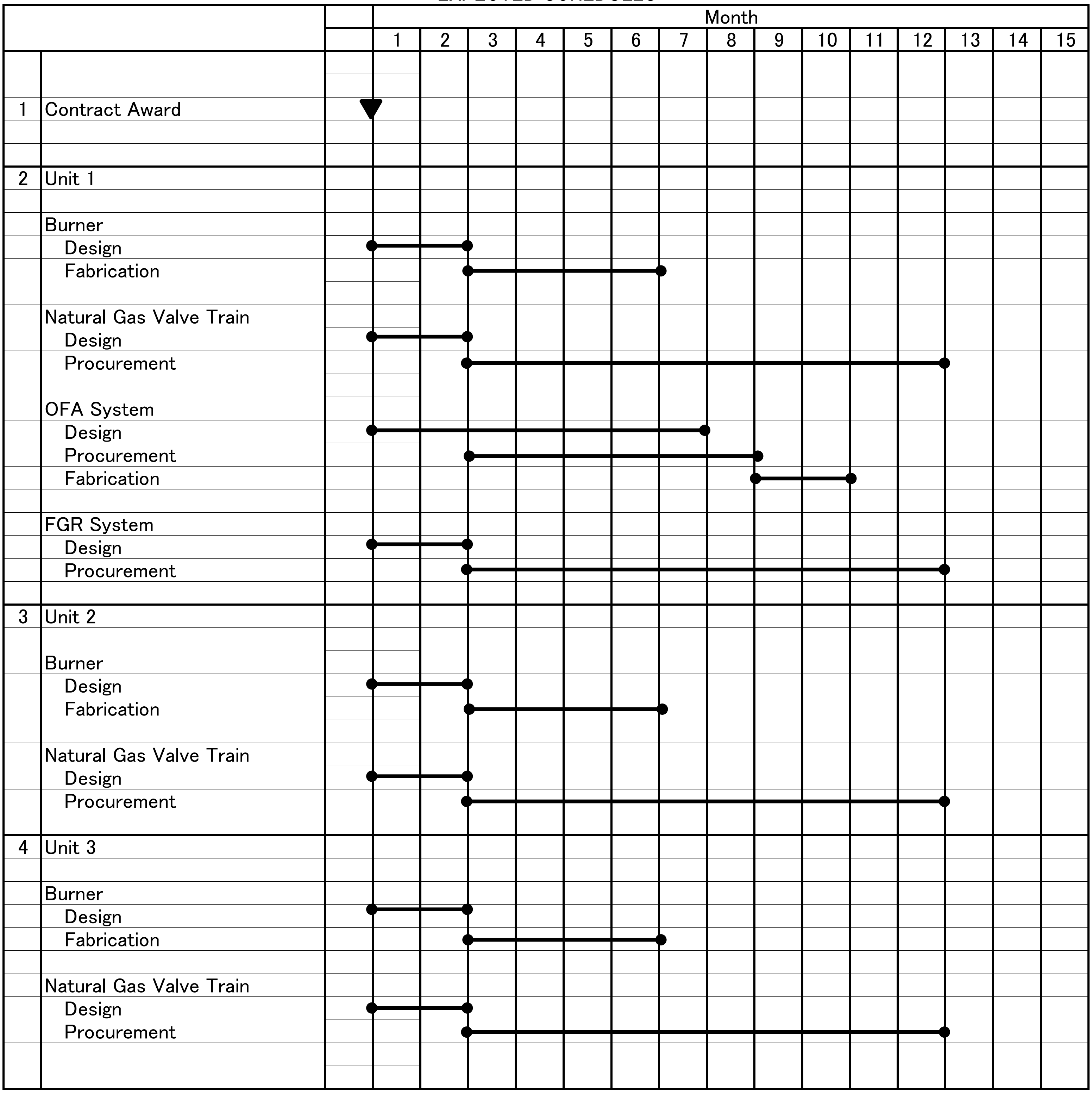



SIMPLIFIED P&ID

ATTACHMENT-2

B&V Confidential Project
Coal to Gas Conversion

EXPECTED SCHEDULES



ATTACHMENT-3

C: by Customer or Others
I: IHI Scope
U: Re-use existing equipment

B&V Confidential Project
Coal to Gas Conversion

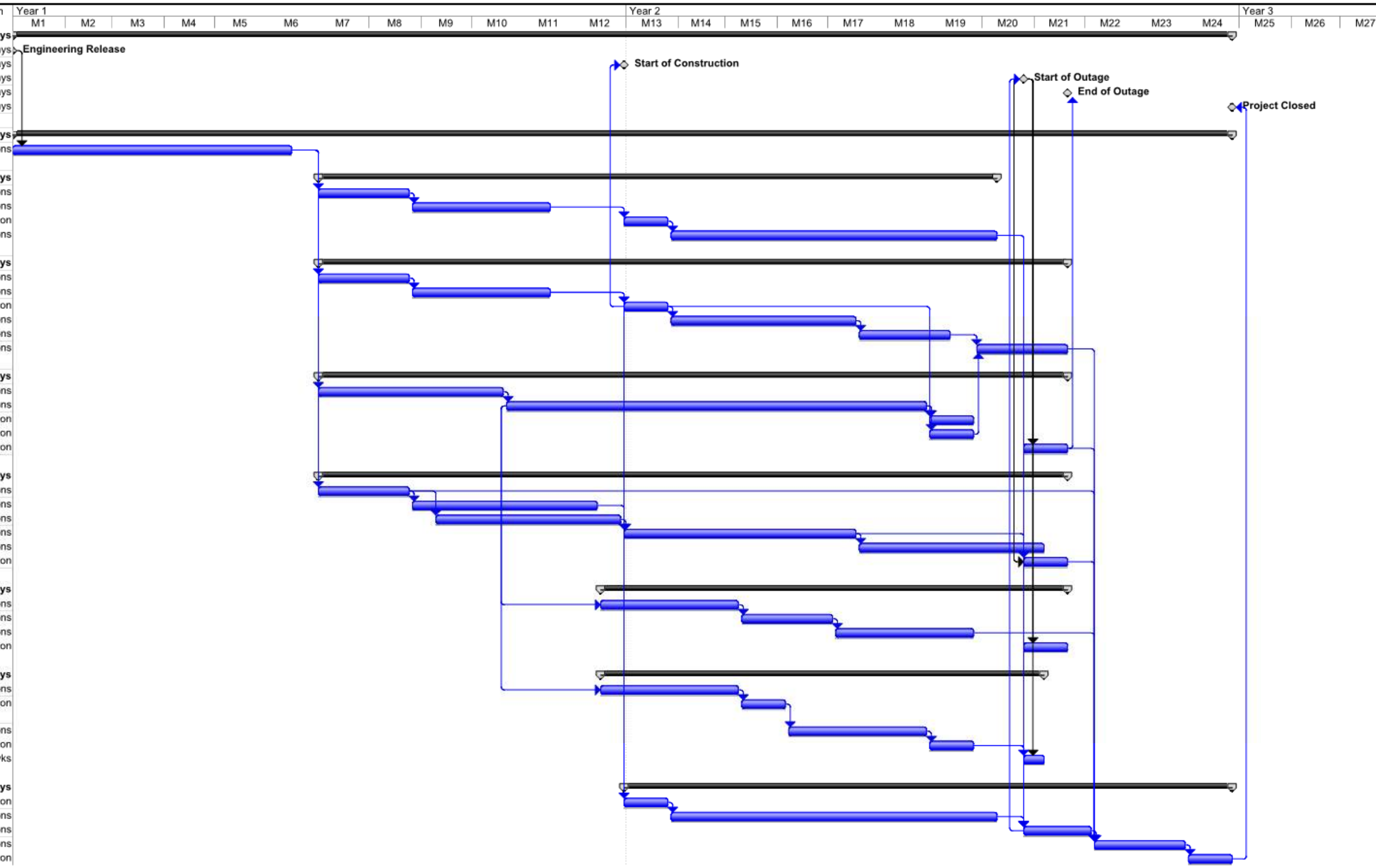
Division of Resposibility

| No | Items | | Unit-1 | Unit-2 | Unit-3 |
|---|---|---|---|---|---|
| 1 | Gas Burner Assembly | | I | I | I |
| 2 | Secondary Air Modification | | I | I | I |
| 3 | Igniter (Class-1) | | I | I | I |
| 4 | Scanner | Main Gas burner | I | I | I |
| | | Igniter | I | I | I |
| | | Cooling Air Blower | U | U | U |
| 5 | SOFA System | OFA Damper Body and Actuator | I | U | U |
| | | OFA Port(Furnace Opening) | I | U | U |
| 6 | FGR System | | I | - | - |
| 7 | Pressure Reducing Skid | | I | I | I |
| 8 | Flow Metering Skid | | I | I | I |
| 9 | Air Flow Monitoring System | | U | U | U |
| 10 | Burner Control Piping Skid | Main Gas Burner | I | I | I |
| | | Igniter | I | I | I |
| 11 | Logic Diagram | Main Gas Burner | I | I | I |
| | | Igniter | I | I | I |
| | | Unit Control System | I | I | I |
| | | Recommended Graphic Display | I | I | I |
| 12 | Control system(Hardware) | | C | C | C |
| 13 | Technical Service | Engineering | I | I | I |
| | | CFD Analisys (Optimize Windbox configuration) | I | I | I |
| | | CFD Analisys (Furnace Part) | I | I | I |
| | | Modeling | I | I | I |
| | | Design | I | I | I |
| | | Fabrication | I | I | I |
| | | Shipping | C | C | C |
| | | Installation | C | C | C |
| | | Commissioning | C | C | C |
| | | Field Supervision | I | I | I |
| | | Combustion Tuning | C | C | C |
| | | PE stamping work(if required) | C | C | C |

# Appendix D. Level 1 Project Schedule

BLACK & VEATCH
Building a world of difference.

| ID | Task Name | Duration |
|---|---|---|
| 1 | **Milestones** | **520 days** |
| 2 | Engineering Release | 0 days |
| 3 | Start of Construction | 0 days |
| 4 | Start of Outage | 0 days |
| 5 | End of Outage | 0 days |
| 6 | Project Closed | 0 days |
| 7 | | |
| 8 | **EPC Bid / Design / Build** | **520 days** |
| 9 | Spec / Bid / Award | 6 mons |
| 10 | | |
| 11 | **Off-Site Gas Line** | **290 days** |
| 12 | Geotechnical / Subsurface Investigation | 2 mons |
| 13 | Underground and Above Ground Utility Design | 3 mons |
| 14 | Mobilization | 1 mon |
| 15 | Piping Installation | 7 mons |
| 16 | | |
| 17 | **On-Site Gas Line** | **320 days** |
| 18 | Geotechnical / Subsurface Investigation | 2 mons |
| 19 | Underground and Above Ground Utility Design | 3 mons |
| 20 | Mobilization | 1 mon |
| 21 | Underground Piping Installation | 4 mons |
| 22 | Above Ground Piping Installation to Power House | 2 mons |
| 23 | Piping Installation in Power House | 2 mons |
| 24 | | |
| 25 | **Fuel Gas Regulating, Metering and Firing Equipment** | **320 days** |
| 26 | Spec / Bid / Award | 4 mons |
| 27 | Design / Fabricate / Deliver | 9 mons |
| 28 | Set Gas Pressure Regulating and Metering Skids | 1 mon |
| 29 | Set Block & Valve Skids | 1 mon |
| 30 | Burner Installation | 1 mon |
| 31 | | |
| 32 | **Ductwork & Dampers** | **320 days** |
| 33 | Geotechnical / Subsurface Investigation | 2 mons |
| 34 | Foundation / Steel / Ductwork Design | 4 mons |
| 35 | Spec / Bid / Award | 4 mons |
| 36 | Design / Fabricate / Deliver Ductwork & Dampers | 5 mons |
| 37 | Install Foundations / Structural Steel / Ductwork | 4 mons |
| 38 | Ductwork Tie-ins | 1 mon |
| 39 | | |
| 40 | **Electrical** | **200 days** |
| 41 | Electrical Design | 3 mons |
| 42 | Fabricate / Deliver Electrical Commodities | 2 mons |
| 43 | Install Electrical Commodities | 3 mons |
| 44 | Relocate/Replace Electrical Components in Classified Areas | 1 mon |
| 45 | | |
| 46 | **DCS Logic Updates** | **190 days** |
| 47 | Logic Development | 3 mons |
| 48 | Award Contract to DCS Supplier to Program & Test Logic Changes | 1 mon |
| 49 | DCS Design | 3 mons |
| 50 | DCS Factory Acceptance | 1 mon |
| 51 | Install and Test Logic at Site | 2 wks |
| 52 | | |
| 53 | **Construction Activities** | **260 days** |
| 54 | Mobilization | 1 mon |
| 55 | Pre-Outage Work | 7 mons |
| 56 | Outage Work | 1.5 mons |
| 57 | Commissioning and Tuning | 2 mons |
| 58 | De-mobilization | 1 mon |




| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Project: LG&E Gas Conversion Sched<br>Date: Fri 2/17/17 | Task | | Progress | | Summary | | External Tasks | | Deadline |
| | Split | | Milestone | | Project Summary | | External Milestone | | |

Project: LG&E Gas Conversion Schedule (REV A)
Date: Fri 2/17/17
1 of 1

**Conceptual Execution Schedule**

# Appendix E. Detailed Cost Estimate

| Description | Unit 1 Conversion Cost | | Unit 2 Conversion Cost | | Unit 3 Conversion Cost | | Balance of Plant | | |
|---|---|---|---|---|---|---|---|---|---|
| | Labor | Material | Labor | Material | Labor | Material | Labor | Material | Total |
| Direct Costs (DC) | | | | | | | | | |
| Burner Equipment | | | | | | | | | |
| Burners, SOFA, FGR System, Gas regulation and metering, Heater | | $7,415,000 | | $3,915,000 | | $6,300,000 | | | $17,630,000 |
| CEMS Equipment | | | | | | | | $325,000 | $325,000 |
| Boiler Study | $300,000 | | $300,000 | | $300,000 | | | | $900,000 |
| Subtotal: Equipment Costs | $300,000 | $7,415,000 | $300,000 | $3,915,000 | $300,000 | $6,300,000 | $0 | $325,000 | $18,855,000 |
| Lighting, Communications, Receptacles | $8,700 | $20,000 | $8,700 | $20,000 | $26,600 | $55,000 | | | $139,000 |
| Electrical Power Distribution Equipment | $21,400 | $26,000 | $21,800 | $29,000 | $26,400 | $37,000 | | | $161,600 |
| DCS | Included | $600,000 | Included | $580,000 | Included | $725,000 | | | $1,905,000 |
| Conduit | $27,600 | $36,400 | $30,400 | $40,200 | $45,600 | $60,200 | | | $240,400 |
| Power Cable | $5,500 | $4,400 | $6,100 | $4,900 | $9,100 | $7,300 | | | $37,300 |
| Control Cable | $2,200 | $7,300 | $2,400 | $8,000 | $3,600 | $12,000 | | | $35,500 |
| Terminations | $38,600 | $8,700 | $42,600 | $9,600 | $63,800 | $14,400 | | | $177,700 |
| Coal Pipe Demolition | $114,000 | | $171,000 | | $256,500 | | | | $541,500 |
| 24" Gas Pipe Line from Plant Boundary | | | | | | | $1,730,400 | $2,036,400 | $3,766,800 |
| River crossing boring/pipe supports | | | | | | | | $135,000 | $135,000 |
| Above Grade CS: 18" Schedule 40 (Gas Supply) | | | $46,100 | $70,200 | $92,100 | $140,300 | | | $348,700 |
| Above Grade CS: 14" Schedule 40 (Gas Supply) | | | | | $69,500 | $74,300 | | | $143,800 |
| Above Grade CS: 12" Schedule 40 (Gas Supply) | $31,800 | $27,300 | | | | | | | $59,100 |
| Above Grade CS: 10" Schedule 40 (Gas Supply) | | | $168,500 | $109,300 | $112,500 | $72,900 | | | $463,200 |
| Above Grade CS: 8" Schedule 40 (Gas Supply) | $46,700 | $23,000 | | | | | $82,000 | $151,500 | $303,200 |
| Above Grade CS: 6" Schedule 40 (Gas Supply) | $55,800 | $24,000 | $111,600 | $91,800 | $167,400 | $115,800 | | | $566,400 |
| Above Grade CS: 3" Schedule 40 (Gas Supply) | $71,700 | $48,200 | | | | | | | $119,900 |
| Ductwork | $155,400 | $186,000 | $11,800 | $14,000 | $1,060,500 | $1,268,500 | | | $2,696,200 |
| Existing Ductwork Modifications | $7,600 | | $7,600 | | $7,600 | | | | $22,800 |
| Structural Steel | $49,600 | $93,000 | $3,800 | $7,000 | $337,400 | $634,300 | | | $1,125,100 |
| Grating | $35,200 | $172,800 | $35,200 | $172,800 | $52,600 | $259,200 | | | $727,800 |
| Handrail | $15,400 | $14,800 | $15,400 | $14,800 | $23,000 | $22,200 | | | $105,600 |

| Description | Unit 1 Conversion Cost | | Unit 2 Conversion Cost | | Unit 3 Conversion Cost | | Balance of Plant | | |
|---|---|---|---|---|---|---|---|---|---|
| | Labor | Material | Labor | Material | Labor | Material | Labor | Material | Total |
| Foundations and Civil Works | | | | | | | $532,000 | $910,000 | $1,442,000 |
| Equipment Installation | $550,000 | | $550,000 | | $550,000 | | $190,000 | | $1,840,000 |
| Construction Equipment, Temp Facility, and Indirect Supervision | $1,045,000 | $750,000 | $1,045,000 | $750,000 | $2,090,000 | $1,150,000 | $760,000 | $800,000 | $8,390,000 |
| Start-Up & Commissioning (7,000 Hours) | $432,000 | | $432,000 | | $432,000 | | $200,600 | | $1,496,600 |
| Subtotal: Construction | $2,714,200 | $2,041,900 | $2,710,000 | $1,921,600 | $5,426,200 | $4,648,400 | $3,495,000 | $4,032,900 | $26,990,200 |
| 30" Gas Pipe Line to Plant Boundary to connection station | | | | | | | | | |
| Excavation (soil 40%) | | | | | | | $234,100 | | $234,100 |
| Excavation (rock 60%) | | | | | | | $468,200 | | $468,200 |
| Sand Bedding 3" deep | | | | | | | $13,000 | $20,500 | $33,500 |
| Backfill (soil) | | | | | | | $374,500 | | $374,500 |
| Backfill (import) | | | | | | | $249,700 | $328,500 | $578,200 |
| Spoil Haul off-site | | | | | | | $208,100 | $1,232,000 | $1,440,100 |
| Small road crossing 30" | | | | | | | $16,700 | $5,500 | $22,200 |
| Highway 27 road crossing 30" HDD | | | | | | | | $500,000 | $500,000 |
| U/G CS: 30" Schedule 40 (main gas offsite) | | | | | | | $4,614,700 | $6,336,000 | $10,950,700 |
| Rig Welder equipment | | | | | | | | $3,000,000 | $3,000,000 |
| NDE x-ray | | | | | | | $1,003,200 | $660,000 | $1,663,200 |
| Trench Box rental | | | | | | | | $48,000 | $48,000 |
| Equipment | | | | | | | | $912,700 | $912,700 |
| Pot holing with Hydro Excavator | | | | | | | | $2,500,000 | $2,500,000 |
| Off-site Indirect Supervision | | | | | | | $850,800 | $4,725,000 | $5,575,800 |
| Subtotal: Off-site Gas Pipe Line | $0 | $0 | $0 | $0 | $0 | $0 | $8,033,000 | $20,268,200 | $28,301,200 |
| Electrical Re-Classification of hazardous areas | $50,000 | $100,000 | $50,000 | $100,000 | $80,000 | $170,000 | | | $550,000 |
| Scaffolding Subcontractor | | $585,000 | | $585,000 | | $585,000 | | | $1,755,000 |
| Subtotal: Allowance | $50,000 | $685,000 | $50,000 | $685,000 | $80,000 | $755,000 | $0 | $0 | $2,305,000 |
| **Total Direct Costs (DC)** | **$3,064,200** | **$10,141,900** | **$3,060,000** | **$6,521,600** | **$5,806,200** | **$11,703,400** | **$11,528,000** | **$24,626,100** | **$76,451,400** |

| Description | | Unit 1 Conversion Cost | | Unit 2 Conversion Cost | | Unit 3 Conversion Cost | | Balance of Plant | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Labor | Material | Labor | Material | Labor | Material | Labor | Material | Total |
| Indirect Costs | | | | | | | | | | |
| Engineering | 10% x DC | $306,420 | $1,014,190 | $306,000 | $652,160 | $580,620 | $1,170,340 | $1,152,800 | $2,462,610 | $7,645,140 |
| Contingency | 15% x DC | $459,630 | $1,521,285 | $459,000 | $978,240 | $870,930 | $1,755,510 | $1,729,200 | $3,693,915 | $11,467,710 |
| Overhead and Profit | 15% x DC | $459,630 | $1,521,285 | $459,000 | $978,240 | $870,930 | $1,755,510 | $1,729,200 | $3,693,915 | $11,467,710 |
| **Total Indirect Costs (IC)** | | **$1,225,680** | **$4,056,760** | **$1,224,000** | **$2,608,640** | **$2,322,480** | **$4,681,360** | **$4,611,200** | **$9,850,440** | **$30,580,560** |
| **Total Capital Investment (TCI) = (DC) + (IC)** | | **$4,289,880** | **$14,198,660** | **$4,284,000** | **$9,130,240** | **$8,128,680** | **$16,384,760** | **$16,139,200** | **$34,476,540** | **$107,031,960** |
| **Tax** | | | | | | | | | | **$0** |
| **Insurance, & Bonds** | 2% | | | | | | | | | **$2,140,639** |
| **Hazardous Material Abatement Allowance** | | | | | | | | | | **$1,000,000** |
| **Owner Costs** | 5% | | | | | | | | | **$5,351,598** |
| **Total Project Costs** | | | | | | | | | | **$115,524,197** |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Potential Budgetary Cost Adjustments** | | | | | | | | | |
| 20" gas line from plant boundary | | | | | | | -$462,000 | -$350,000 | **-$812,000** |
| Boiler Heating Surface Modifications to achieve Full Load Unit Output (Allowance) | | $6,000,000 | | $7,000,000 | | $10,000,000 | | | |