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PERFORMANCE IMPROVEMENTS AT THE BOARDMAN COAL PLANT AS A RESULT OF TESTING AND INPUT/LOSS MONITORING

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ABSTRACT

This paper presents methods and practices of improving heat rate through testing and, most importantly, through heat rate monitoring. This work was preformed at Portland General Electric's 585 MWe Boardman Coal Plant, which used two very different Powder River Basin and Utah coals ranging from 8,100 to over 12,500 Btu/lbm. Such fuel variability, common now among coal-fired units was successfully addressed by Boardman's on-line monitoring techniques.

Monitoring has evolved over the past ten years from a Controllable Parameters approach (offering disconnected guidance), to a systems approach in which fuel chemistry and heating value are determined on-line, their results serving as a bases for Second Law analysis. At Boardman on-line monitoring was implemented through Exergetic System's Input/Loss Method. Boardman was one of the first half-dozen plants to fully implement Input/Loss.

This paper teaches through discussion of eight in-plant examples. These examples discuss heat rate improvements involving both operational configurations and plant components: from determining changes in coal chemistry and composite heating value on-line; to recognizing the impact of individual rows of burners and pulverizer configurations; to air leakage identifications; to examples of hour-by-hour heat rate improvements; comparison to effluent flows; etc. All of these cases have applicability to any coal-fired unit.

NOMENCLATURE

BBTC = Useful energy flow to the working fluid, as derived directly from the combustion process, Btu/hr.
FCI_i = Fuel Consumption Index for an i_{th} irreversible component or process, Btu/hr.
FCI_{Power} = Fuel Consumption Index for power generation, Btu/hr.
g = Specific exergy, Btu/lbm.
G_{in} ≡ Total of all exergy in-flows and shaft powers supplied to a thermal system, Btu/hr.
HBC ≡ Firing Correction (i.e., "energy credit"), Btu/lbm_{AF}.
HHV = As-Fired (wet-base) higher heating value, Btu/lbm_{AF}.
HHVP = As-Fired (wet-base) higher heating value corrected for constant pressure process, Btu/lbm_{AF}.
HNSL ≡ Non-Chemistry & Sensible Heat Losses, Btu/lbm_{AF}.
HPR_{Act} ≡ Enthalpy of Products, actual conditions, Btu/lbm_{AF}.
HRX_{Act} ≡ Enthalpy of Reactants, actual conditions, Btu/lbm_{AF}.
HR = Unit heat rate (gross, total system), Btu/kWh.
hr_j = Differential heat rate associated with any j_{th} component or process , ΔBtu/kWh.
HSL ≡ Stack Losses, Btu/lbm_{AF}.
I = Irreversibility, Btu/lbm.
m_{AF} = As-Fired fuel mass flow rate (wet with ash), lbm_{AF}/hr.
∂Q = Differential heat transfer, ΔBtu/hr.
T_{Cal} = Calorimetric temperature for HHV determination, F.
T_{Ref} ≡ Reference temperature for Second Law analyses, F.
W_{Fan} = Brake fan power, Btu/hr.
W_{Pump} = Brake pump power, Btu/hr
W_{output} = Gross electrical generation, Btu/hr or kWe.
∂W = Differential shaft power, ΔBtu/hr.
η_B = Boiler efficiency (HHV-based), --.
η_C = Combustion efficiency (HHV-based), --.
η_A = Boiler absorption efficiency, --.

INTRODUCTION

Boardman is a 585 MWe unit burning Powder River Basin and Utah coals; coals having remarkably different chemistries and heating values (varying from 8,100 to over 12,500 Btu/lbm). The steam generator was provided by Foster Wheeler, as are the 2 MB type and 6 MBF type pulverizers. The steam turbine is a four-flow Westinghouse product, with recently upgraded LP rotors. The plant operates under a Westinghouse WDPF Distributed Control System. Exergetic Systems supplied the Input/Loss Method and its associated software (Lang, 1994-2002). The WDPF communicates with Input/Loss via an interface provided by Real Time eXecutives, (RTX) of Wrentham, MA. Output communications from Input/Loss are available through both RTX, and a ModBus protocol provided by KEPware, Inc. of Yarmouth, ME.

As common with most coal-fired units, traditionally Boardman's plant engineers were monitoring only the so-called Controllable Parameters. Heat rate was determined on a monthly basis by using totalized measured coal flow, and heating value based on random samplings. To instigate improvement, plant engineers chose to mark a bright line between a Performance Monitoring Program, versus the traditional Controllable Parameters. At Boardman, this meant a holistic approach was needed - a systems approach - implementing both the Input/Loss Method and follow-up testing, training and maintenance programs.

The Input/Loss Method determines coal chemistry, heating value and coal flow on-line, using principally Continuous Emission Monitoring System (CEMS) instrumentation. Input/Loss Methods include the correction of CEMS measurements such that stoichiometric consistencies are assured. Such consistencies are judged against certain fuel characteristics, found constant for a given mined coal (Lang, 1999), involving multidimensional optimization (Lang, 2002a). The Method relies on a sophisticated boiler simulator and turbine cycle computations. Input consists of routine plant data, reference fuel characteristics, and O_2, CO_2 and H_2O effluents. Its base technology has been documented in four serial ASME papers (Lang, 1998 for an over-view). The Input/Loss Method includes use of Second Law analyses, determining Fuel Consumption Indices for all major components and processes (Lang, 2002b). Fuel Consumption Indices indicate to the operator why fuel is being consumed: for power generator, and for over-coming irreversible losses; thus to minimize losses and maximize power generation.

INPUT/LOSS DETAILS

The Input/Loss Method is a unique process which allows for complete thermal understanding of a power plant through explicit determinations of fuel and effluent flows, fuel chemistry including ash, fuel heating value and boiler efficiency. Understanding of steam generator performance is had from computer simulations principally based on: internally updated fuel chemistries and heating values; effluents concentrations; and energy flow to the working fluid. Plant indicated fuel flow is not used, although when found consistent, as at Boardman, its comparison to the computed serves as an excellent “sanity check” for general Input/Loss performance. Measured effluent flows are never used. Boiler efficiency, η_B, is defined by dividing its definition into two components, a combustion efficiency and boiler absorption efficiency (Lang, 2000):

$$\eta_B = \eta_C \, \eta_A \tag{1}$$

To develop the combustion efficiency term, Input/Loss employs an energy balance uniquely about the flue gas stream (i.e., the combustion gas path). This balance is based on the difference in enthalpy between actual products HPR_{Act}, and actual reactants HRX_{Act}. Actual, As-Fired, Enthalpy of Reactants is defined in terms of Firing Corrections: $HRX_{Act} \equiv HRX_{Cal} + HBC$. The term HRX_{Cal} is the gross heat released given complete combustion (i.e., ideal products) at the calorimetric temperature, T_{Cal}. Combustion efficiency is then defined in terms which are independent of fuel flow but akin to PTC 4.1's Input-Output Method.

$$\eta_C = \frac{- HPR_{Act} + HRX_{Act}}{HHVP + HBC} \tag{2}$$

This formulation was developed to maximize accuracy. Typically for coal-fired units, over 95% of the boiler efficiency's numerical value is comprised of η_C. Indeed, all individual terms making up η_C have the potential of being determined with high accuracy. HPR_{Act} is determined knowing effluent temperature, complete stoichiometric balances, and accurate combustion gas and water properties. HRX_{Act} is dependent on heating value, ideal products and Firing Corrections, HBC. The HBC term applies needed corrections for the <u>reactant's sensible heats</u>: fuel, combustion air, limestone if used, water in-leakage and energy inflows ... all referenced to T_{Cal} such that the term ($- HPR_{Act} + HRX_{Act}$) is stoichiometrically conserved relative to a measured heating value, HHV.

The boiler absorption efficiency is developed from the boiler’s “Non-Chemistry & Sensible Heat Loss” term, HNSL; it is the <u>product's sensible heats of non-combustion processes</u>.

$$\eta_A \equiv 1.0 - \frac{HNSL}{- HPR_{Act} + HRX_{Act}} \tag{3}$$

$$= 1.0 - \frac{HNSL / \eta_C}{HHVP + HBC} \tag{4}$$

HNSL is defined through iterative techniques, independent of fuel flow, comprising radiation & convection losses, pulverizer rejected fuel losses (or fuel preparation processes), and sensible heats in: bottom ash, fly ash, effluent dust and effluent products of limestone. HNSL is determined using a portion of PTC 4.1's Heat-Loss Method.

With a computed boiler efficiency the As-Fired fuel flow rate, m_{AF}, is then back-calculated from the traditional expression of boiler efficiency, of critical importance to Input/Loss Methods.

$$m_{AF} = \frac{BBTC}{\eta_B \, (HHVP + HBC)} \tag{5}$$

Once fuel flow is correctly determined, stoichiometrics is then used to resolve all boiler inlet & outlet mass flows, including effluent flows required for regulatory reporting. Unit heat rate associated with a power plant follows directly from Eq.(5).

$$HR = m_{AF} \, (HHVP + HBC) / W_{output} \tag{6}$$

$$\equiv BBTC / (\eta_B \, W_{output}) \tag{7}$$

where BBTC, for a conventional coal-fired plant, is the useful energy flow to the turbine cycle’s working fluid. Note that the definition of overall boiler efficiency, comprising η_C and η_A of Eq.(1), and that of PTC 4.1, can be demonstrated to be <u>identical</u> (Lang, 2002c).

An obvious objective at Boardman, as found at most coal-fired units, is to determine thermal performance in light of highly variable fuel. This is achieved through integration of stoichiometrics with high accuracy boiler efficiency. As formulated, consistency is guaranteed between boiler efficiency, As-Fired heating values, computed fuel and effluent flows and unit heat rate. With such consistency as a bases, thermodynamic losses throughout the system are then determined employing Second Law analysis.

FUEL CONSUMPTION INDICES

The maximum potential power which could be produced or consumed by the working fluid in any process is measured by its associated change in exergy flow. The net change for any process is:

$$\Delta G \equiv \int mdg = \Sigma mg_{outlet} - \Sigma mg_{inlet} \tag{8}$$

Exergy audits permit performance engineers to quickly determine the degree (termed effectiveness) components are consuming or producing actual versus potential power. An important concept is that total exergy flows are destroyed when viewing an active system interfaced with its environment. Thus in the process of power production exergy bound in the fuel must eventually be returned to the environment, manifested through system losses and electrical generation - and nothing more.

Thermodynamic irreversibilities are these system losses, the unrecoverable losses associated with any thermal process (the loss of potential power from the system). For a process assumed interfaced with its environment, irreversibility is the measure of exergy destruction associated with the system relative to its environment. Irreversibility is defined, for a process or system, by:

$$I = \int (1 - T_{Ref}/T)\,\partial Q - \int \partial W - \int mdg \tag{9}$$

Eq.(9) is a simple accounting of a process' potential and actual powers. The $\int(1 - T_{Ref}/T)\,\partial Q$ term is the Carnot conversion of energy flow to power, via a possible motive $\int \partial Q$ heat transfer, a negative term if from the process. The Carnot conversion can be thought of as the power equivalent resultant from heat transferred from the process directly to the environment. The $\int \partial W$ and $\int mdg$ terms represent differences between actual shaft power (produced or supplied), and the actual exergy change of the process (potential power supplied or produced to the fluid), thus a net lost of potential power. The sign of $\int \partial W$ is positive if power is produced from the system. For example, if a turbine produces $+0.3980 \times 10^9$ Btu/hr shaft power, from a -0.5044×10^9 Btu/hr decrease in steam exergy, assuming $\partial Q = 0.0$, then from Eq.(9) the irreversibility is given by $0.1064 \times 10^9 = 0.0 - 0.3980 \times 10^9 - (-0.5044 \times 10^9)$; always the positive difference between potential and actual powers. This turbine's effectiveness is 78.9% $(0.3980 \times 10^9 / 0.5044 \times 10^9)$.

At the system level, irreversibility is a measure of the exergy destroyed and thus is directly proportional to fuel consumption. Again, of the total exergy and power inputs to a system, only irreversibilities and power output will result. This can be expressed by Eq.(11), where the total exergy and power inputs to the system defines G_{in}.

$$G_{in} \equiv m_{AF}\, g_{Fuel} + m_{AF}\, g_{Air} + \Sigma G_{Misc} + \Sigma W_{Pump} + \Sigma W_{Fan} \tag{10}$$
$$= \Sigma I_i + W_{output} \tag{11}$$

Eq.(11) represents a clear statement of the Second Law applied to a power plant. From this concept the Fuel Consumption Index is developed by simply dividing through by G_{in} for individual components or processes and the power production.

Fuel Consumption Indices are a measure of fuel consumed; they assign thermodynamically to those individual components or processes their "fuel consumption". FCIs quantify the exergy and power consumption of all components and processes relative to the total exergy and power supplied to the system; by far the predominate term (and having the greatest numerical complexity) is the fuel's total exergy, $m_{AF}\, g_{Fuel}$. Based on Eq.(11), FCI is defined for non-power components and processes (such as combustion), and the power production process by the following:

$$FCI_i \equiv 1000 \frac{I_i}{G_{in}} \tag{12}$$

$$FCI_{Power} \equiv 1000 \frac{W_{output}}{G_{in}} \tag{13}$$

As used in Eqs.(12) & (13) the terms G_{in}, irreversibility and power all employ units of Btu/hr. Although FCIs are unitless, they are arbitrarily multiplied by 1000, thus $\Sigma FCI_j = 1000$ (where j represents all components and processes).

It can be shown that individual FCI_j directly lead to differential heat rates, hr_j, such that: $HR = \Sigma hr_j$. Further, it can be shown that FCI_{Power} also leads directly to this same classical unit heat rate, *HR*, as defined by Eqs.(6) & (7):

$$HR = (1000 / FCI_{Power})\,(3412.1416 + hr_{Envir}) \tag{14}$$

The "Environmental" differential heat rate term, hr_{Envir}, relates to the impact the environment plays, thermodynamically, on the supply stream exergies; it is typically numerically small and for sensitivity studies can be considered constant (see Lang, 2002b).

When presented in a Control Room the simplicity offered by the FCI approach is a considerable improvement on the traditional Controllable Parameters method. The operator must only maximize FCI_{Power} by minimizing ΣFCI_i. Since FCIs sum to 1000, any operational change an operator executes is registered by a balancing among FCIs. A decrease in FCI_{Power} must be offset by FCI_i increases; or, if $\Delta FCI_{Power} \approx 0.0$, a change in one or more FCI_i will be off-set by other non-power FCIs.

Boardman's engineering staff relies on the belief that their operators know the system, they understand what executions are occurring - and with FCIs - they now have quantitative knowledge as the impact on thermal performance. Examples of using these techniques follow (see Deihl, 1999 for a parallel study).

PLANT SET-UP AND DATA TRAIN

The on-line system implementing these principles consists of three basic components. The first is the plant's DCS used to gather system data; it is also used to display key output parameters (FCIs, efficiencies, unit heat rate, etc.) for operator feedback. The second component is the Performance Monitor Server which acts as interface between the DCS and a "Calculational Engine". The Engine, as the third component, runs the Input/Loss Method. Within the Engine, calculations are completed, the results of which are key

Plant Performance Parameters, notably real time boiler efficiency, FCIs and unit heat rate. At Boardman, the Engine is set up to cycle Input/Loss Methods every two minutes based on 15 minute running averages of all applicable plant data. All Engine results are available as output to the WDPF system for operator display, via a ModBus interface.

The WDPF's database communicates with the Calculational Engine via an RTX interface. The RTX program resides in one of the DCS's MMIs. RTX both obtains selected plant data from the WDPF data highway, and communicates this data to its own historical database (HDB) via LAN. The RTX historical database resides in a separate computer acting as a server. Additionally, selected Engine results are stored in the RTX's HDB. All data, be it real time plant data via WDPF, or Engine results are available to plant personnel at their desk-top personnel computers. This information is available as real time or historical data. This information can be displayed graphically in the form of trends, or via spreadsheets. Also, Engine output is available to the WDPF data highway for graphical display or trend plots offered by WDPF. Plant operators typically choose to archive at least boiler efficiency, unit heat rate, and FCIs in the WDPF's historian.

INSTRUMENTATION

Instrumentation is, of course, an important aspect of performance engineering. Indeed, instrumentation, testing and analysis are the three "legs" of the performance engineering "stool". Recognizing this, the Boardman staff as part of the installation of an on-line monitoring program, preformed a detailed review of all plant instrumentation. Boundary conditions were established for the Turbine Cycle, steam generator heat exchangers, and plant effluents. Although most of the required thermometer wells and pressure taps were in place, some key instrumentation was lacking.

The following is a list of instrumentation added to the plant as a result of the on-line monitoring program:

A. Temperature and pressure instruments at both LP Turbine crossover piping (although pressure nipples were present they were not tapped through!).

B. Temperature and pressure instruments were added at the outlet of the high pressure feedwater heater. A thermometer well and pressure tap were required.

C. In the stack, there are two visible effluent streams due to stratified flow, thus to eliminate any questions when measuring, an additional O_2 instrument was added directly opposite the existing O_2 probe. Most importantly, a stack H_2O instrument was added (by Sick Optical Co.). Although initially planned (but not implemented), it became apparent that with variable moisture in the coal, it would be absolutely necessary to measure stack moisture. Although a <u>consistent</u> H_2O meter was required, its <u>absolute accuracy</u> was not a requirement given Input/Loss' ability to correct any effluent signal. Although the stack CO_2 instrument was physically present as part of CEMS, its signal needed to be added to the plant's WDPF data highway.

D. Thermocouples were added to existing wells at the main and reheat steam turbine inlets. Note, the plant now controls main and reheat steam temperatures based on these temperatures as appropriate for true turbine cycle monitoring (not at the steam generator *per se*).

E. Thermocouples were added in existing wells at the Upper and Lower Economizer, and at the outlet lines of the Primary Superheater.

F. At both Boiler Feed Booster Pumps (BFBP) and Boiler Feed Pumps (BFP), thermometer wells were added at each pump's discharge lines to facilitate individual pump testing (involving high accuracy ΔT measurements). Also, importantly, pressure taps and wells were added at the discharge of the booster stage of the BFPs (Boardman's superheat spray flows are unusually high, thus requiring another high accuracy ΔT measurement).

G. New steam flow orifices were added in the steam lines feeding the Auxiliary Turbines (which at Boardman drive both BFP and BFBP).

H. Two flow orifices were added to monitor turbine gland seal steam flow leakages, and a third flow orifice was added to monitor Gland Steam Condenser flows.

With the exception of the test points added to BFP and BFBP, signals from the new instrumentation were added to the plant's DCS, and routinely archived in its Historian.

EXAMPLE A: SYSTEM AIR LEAKAGE

When modeling the plant for on-line monitoring, preliminary boiler analysis, using EX-FOSS (Lang, 2002c), pointed towards unrealistically high air in-leakage. Initial indications required a value of more than 20% air leakage. With this warning in-hand, subsequent testing on May 5, 2000 revealed a low boiler efficiency of 83.21%. As part of the testing program, detail oxygen and CO_2 profiles at the boiler's exit were then obtained. Additionally, much work was put into looking for tramp air sources.

Several casing leaks were discovered, as well as minor sources of tramp air leakage. Corrections were made or were planned for a forthcoming Spring outage. Engineering judgement and EX-FOSS analyses suggested that the identified in-leakages could not account for the leakage required to meet stoichiometric balances.

However, two sources of leakage which could account for computed results were eventually identified. The first was the out-of-service pulverizers. It was known that the original design of the burner sleeve damper was not adequate. Due to this, the plant operators chose to keep all burner sleeve dampers fixed in place at 3 inches open and use the outer air registers for burner adjustment. With a pulverizer out-of-service, the only way to isolate secondary air to the burner was to shut the outer air registers. With a burner sleeve damper fixed in place at 3 inches open, and having its associated outer air register shut, secondary air flow could not be isolated in the out-of-service burners. The plant typically runs with seven mills in-service at full load. Thus with a mill out-of-service, and its associated sleeve damper fixed in place, a significant source of air in- leakage was present. During the 2001 Spring outage, modifications were completed to the sleeve mechanism for all 32 burners allowing proper operation. Again, this was done for the purpose of isolating tramp air from the out-of-service mill(s).

The second source of high air in-leakage was found by a detailed examination of the boiler's exit flue oxygen profiles (not involving plant instrumentation, but an independent mobile lab.). Table 1 presents Boiler O_2 readings. Note the heavily stratified O_2 concentrations across the back of the duct; and, most significantly, in the up and down directions. These readings were obtained while the plant was controlling to an exit flue O_2 set point of 2.8% (interestingly, operations believed they had no difficulty maintaining this set point!). Furthermore, the plant was using fourteen in-situ O_2 probes, thus believing that boiler O_2 was well understood. The reality was that half of these probes were mounted at the 6 foot level and the other half at the 12 foot level, in a 22 foot deep duct. *Further, their mountings were located in such a way as to bias burners feeding the "front" of the boiler. At this time, mills at the "back" of the boiler were favored for out-of-service, thus further masking air leakage effects*.

With the information obtained from the traverse of the exit flue and further EX-FOSS sensitivity analyses, the plant took its O_2 probes and moved them to monitor the centroids of equal areas in the upper duct. To cover the centroids of equal areas for the entire duct, it would require an additional twelve O_2 probes. The plant elected not to install these additional probes, preferring to investigate the results of testing performed after the 2001 spring outage.

The results of the these two modifications proved to be outstanding. The plant now uses the burner sleeve dampers for burner adjustments, and rarely adjusts the burner air registers. Of note is the reduction in Wind Box pressure. Prior to this modification, the Wind Box pressure was typically 4.5 to 5.5 Δin-water at full load. With the current burner sleeves opened to between 8 to 9 inches, Wind Box pressure has decreased to 1.5 to 2.0 Δin-water, resulting in reduced Forced Draft Fan loading. This load reduction is due to a decrease Forced Draft Fan loading, caused by less throttling at the sleeve dampers. Most importantly, this modification has allowed the out-of-service pulverizer to be effectively isolated, thus mitigating a major source of air in-leakage. The out-of-service burners have their sleeve dampers opened slightly for burner tip cooling.

In general support of this work, Figure 1 illustrates a year of stack effluent data. Note the reduction in stack O_2 and total air flow. Stack O_2 decreased from approximately 7.0% to 5.5%. Stack CO_2 increased from 10.66% to over 12%. Clearly this data indicates an increase in boiler efficiency. Computed boiler efficiency after the Spring 2001 outage eventually rose to between 85.0% and 85.6%, versus the earlier 83.21%; accounting for typically a 2% increase in boiler efficiency.

Another traverse of the Boiler's exit O_2 was then performed. This traverse was used to validate modifications completed during the Spring outage. Table 2 presents results and should be compared to Table 1. Note the significantly lower readings, and their improved distributions. This traverse was taken while controlling an O_2 set point to 2.50%, 0.30% lower than earlier practice. Of course, these readings do not reflect a simple set point change, but improved air in-leakage and improved controls. As confirmation, CO_2 readings taken across the Air Pre-Heaters indicated a component leakage of approximately 5%, versus the original system leakage of ≈20%.

Obviously, burner sleeve damper modifications and O_2 probe placements are largely responsible for the observed improvement in boiler efficiency. It is felt by the authors that modifying the O_2 probe placement had the greatest impact on boiler efficiency by improving O_2 control. Plant controls combustion air by controlling oxygen at the Boiler's exit.

Table 1:
O2 Concentrations Before Modifications

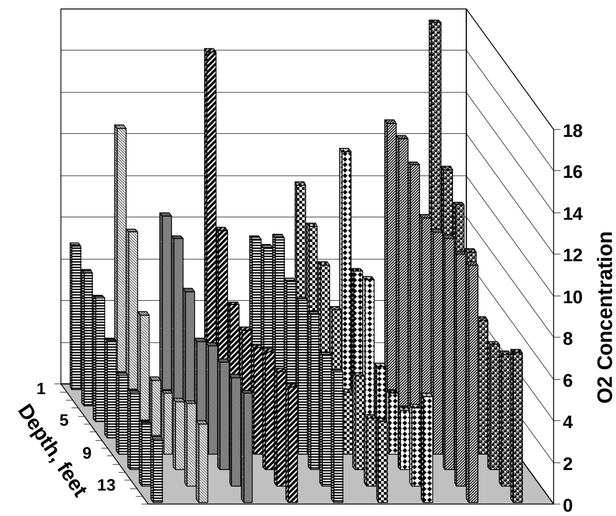


Table 2:
O2 Concentrations After Modifications

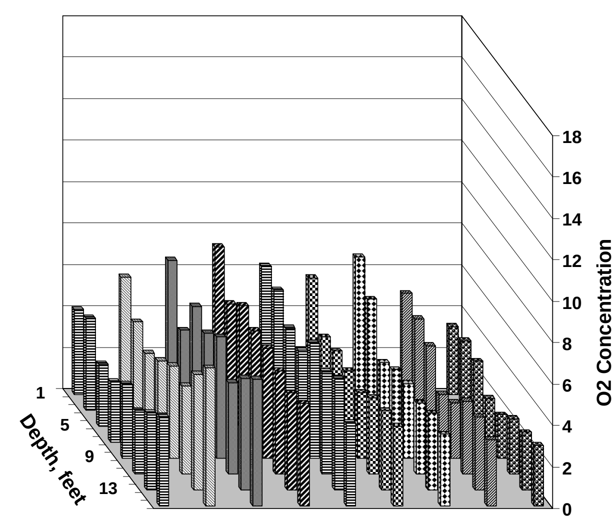
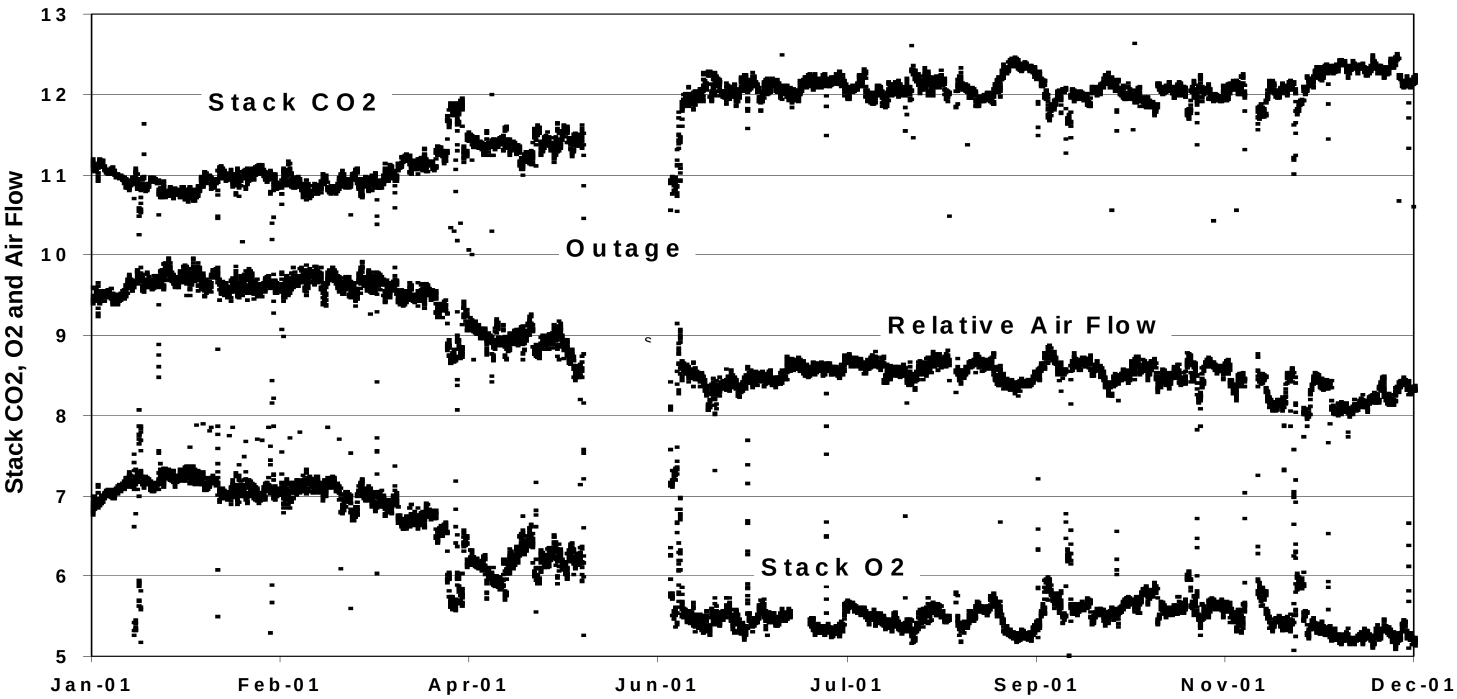


Figure 1: Results of 2001 Air Leakage Work



Based on exit flue testing the Plant was inaccurately measuring Boiler oxygen which resulted in high combustion air. Lowering excess air is traditional, but the subtlety involved changing where Boiler oxygen was being monitored. Also, modifying the sleeve dampers significantly reduced tramp air from out-of- service mills. And, with less throttling due to wider open sleeve dampers, there is less flue gas stratification in the boiler, hence a more accurate Boiler O_2 determination. After this effort, combustion stoichiometrics were found consistent by EX-FOSS.

Boiler efficiency improved by dogged persistence to resolve stoichiometric consistencies. During the installation of the Calculational Engine and initial steam generator modeling, boiler efficiency calculations could not be confirmed without arriving at an unrealistically high air in leakage. The end result was a notable increase in boiler efficiency.

EXAMPLE B: BURNER ADJUSTMENTS - I

The Engine computes FCIs for all major steam generator components, power generation process and miscellaneous processes. Eq.(11) states, given a system is being supplied with a potential for power, that only power and losses are produced. FCIs indicate the distribution of such power and losses through fuel consumption. At Boardman, losses may occur in the following modeled components or processes: Primary Superheater, Finishing Superheater, Reheater, Upper Economizer, Lower Economizer, boiler water walls, Finishing Superheater sprays, Primary Superheater sprays, Stack losses, collective Turbine Cycle (non-boiler interfaced) components, and the combustion process. Since $\Sigma FCI_j = 1000$, an increase in a heat exchanger or process FCI_j, must be accompanied by a decrease in another. If FCI_{Power} increases (good), given that power is being more effectively produced, losses somewhere in the system have (and must have) decreased. Of course, a ceratin component FCI_i could increase (higher irreversible losses), but be just off-set by another non-power component or process, e.g., the combustion process; negating any effects on FCI_{Power}.

Figure 2-3: Burner Adjustments (before and after)

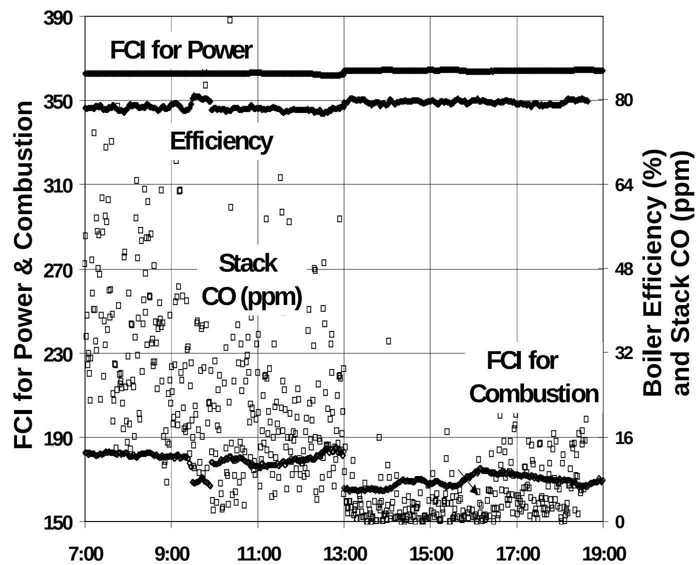


Figure 2-3 presents an example of changes in FCIs due to a burner requiring adjustment, indicating typical data associated with before and after adjustments. Typically, the Boardman plant runs with minimal CO of approximately 6-7 ppm. In Figure 2-3, note the

Figure 4: Effects of Burner Mis-Adjustment

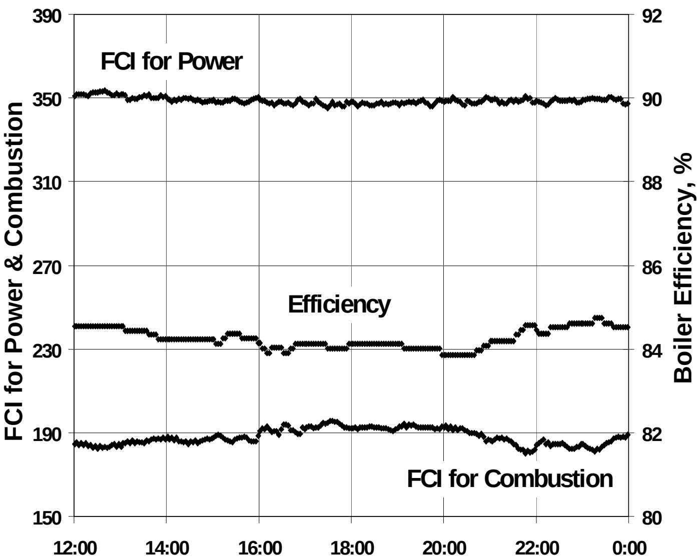
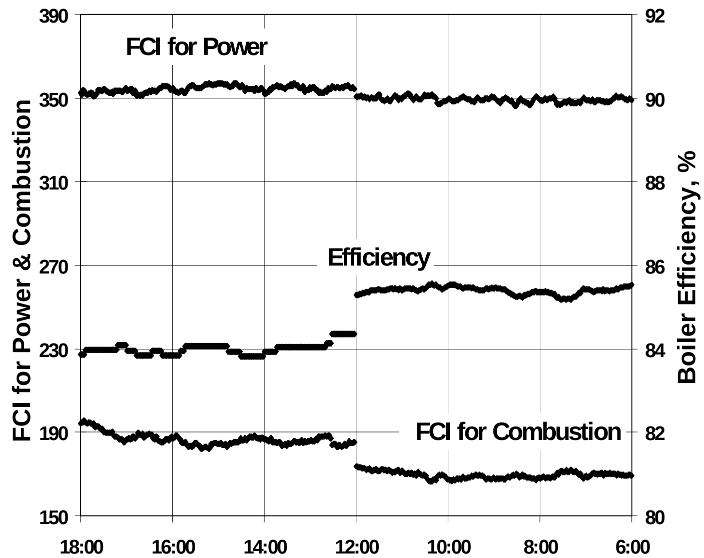


Figure 5-6: Pulverizer Classifier Upgrade (before & after)



correspondence between high CO, high Combustion FCI and corresponding lower FCI_{Power} - versus these values associated with low CO. Any increase in CO provides an immediate indication of burner problems. Notably, changes in FCI_{Power} are a direct indication of changes in unit heat rate via Eq.(14) . Figure 2-3 presents results after burners were adjusted, noting the decrease in Stack CO along with a decrease in the FCI for Combustion opposing an expected increase in the FCI_{Power}.

EXAMPLE C: BURNER ADJUSTMENTS - II

Figure 4 illustrates another example of adjusting burners, this time a mis-adjustment. Note how FCI for Combustion trended higher, with a slight decrease in FCI_{Power}. Obviously operators were proceeding in the wrong direction; they recognized this given a visual record. After the adjustments were reversed, FCI for Combustion trended lower. Computed unit heat rate followed these trends, principally caused by changes in boiler efficiency, representing approximately 3/4% $\Delta\eta$. At the time of this example typical boiler efficiency was 84.6% as the plant was the process of a coal conduit study (Example D); additionally, the plant was still learning how best to optimize the new burner sleeve modifications. The 3/4% $\Delta\eta$ in efficiency represented over 90 ΔBtu/kWh improvement in heat rate which would of gone undetected.

EXAMPLE D: COAL CONDUIT STUDY

At the completion of the Spring 2001 outage, the plant hired Storm Technologies, Inc. of Albemarle, NC, as consultants to assess pulverizer performance. Clean air flows, dirty air flow (air borne coal), coal fineness and bulk coal flows were determined for each mill. At Boardman there are four burners (at the same level and boiler face) for each mill, with eight mills there are 32 burners. Each burner has its own conduit, 32 conduits. As a result of this testing, flow orifices were installed in two coal conduits. Additionally, the plant changed classifier vanes in all pulverizers with Storm Technologies' recommended design. The consultant pointed out that classifier vanes are not only responsible for coal fineness but for flow distribution. Naturally, it is desirable to have equal coal flows in all conduits. Prior to the classifier installation, individual coal conduit flows deviated as high as 10% to 15% from a mill average. After the new classifier vane installation, individual conduit flows deviation was less than 5%.

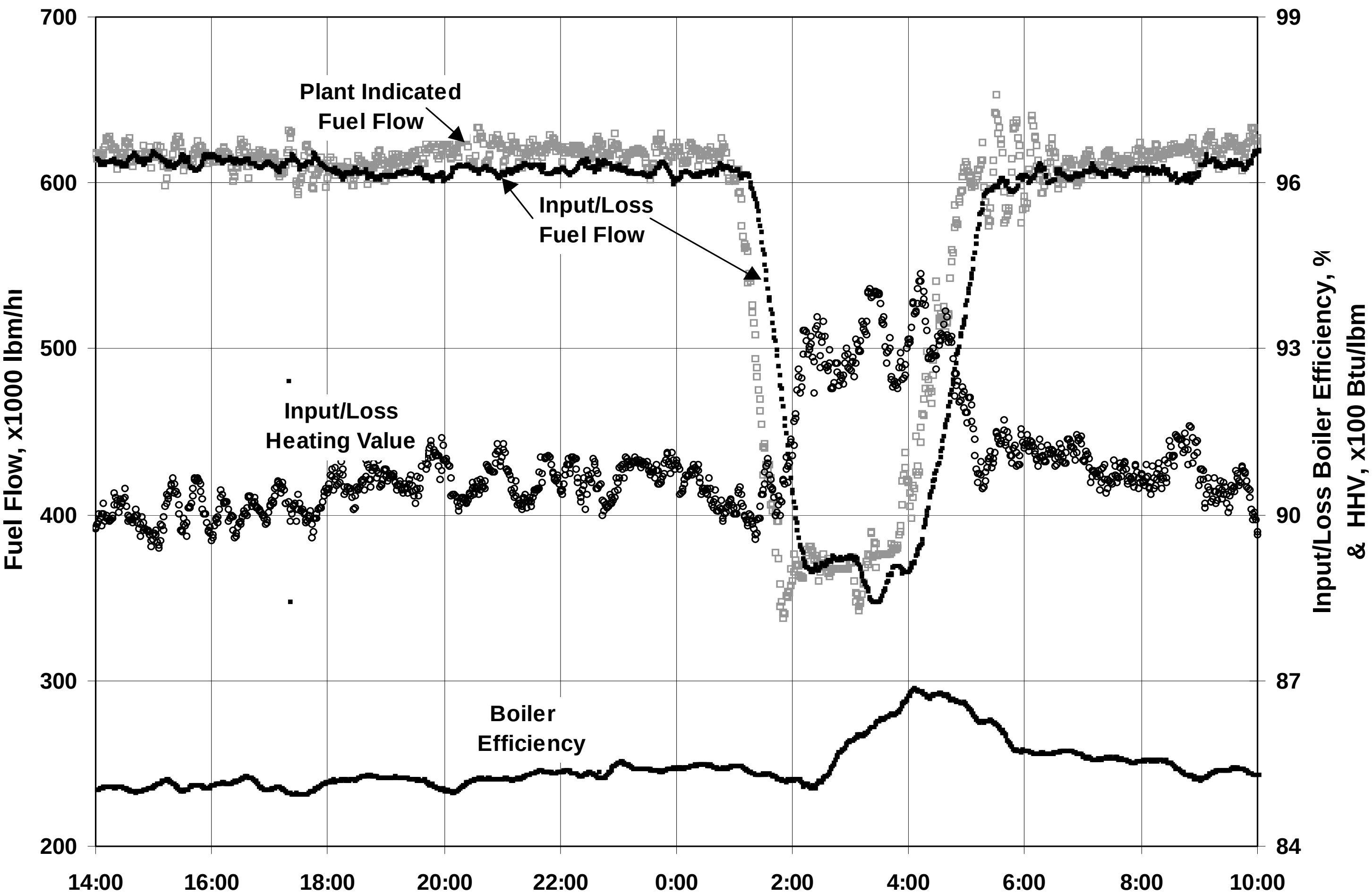
Figure 5-6 presents the results FCI for Combustion, FCI_{Power} and boiler efficiency before and after modifications. Figure 5-6 provides an excellent representation of the consistency of Engine computations, needed and used to properly evaluate the modifications to the classifier vanes. Boiler efficiency improved approximately 1.40% $\Delta\eta$. The classifier vane upgrade occurred over a period of five months (Figure 5-6 presents sampled data using relative Δtimes).

Given a long installation period, other system changes were occurring; as observed in Figure 5-6, FCI_{Power} has slightly <u>decreased</u> indicating that heat rate slightly degraded. Investigation revealed that the FCI for the Turbine Cycle was found degraded due to higher back pressure, thus the cause of the slight system degradation. However an improved FCI for Combustion is consistent with a strong improvement in boiler efficiency, one would not expect steam generator heat exchangers to degrade (i.e., higher irreversible losses) while at the same time FCI for Combustion to improve - but such a situation is possible, lower FCI_{Power} values must be investigated.

EXAMPLE E: SENSITIVITY TO CHANGING FUELS

Figure 7 shows Input/Loss principle outputs during a transient in which a pulverizer was taken out-of-service, and then returned to service four hours later. This altered the mix of low and high energy coals feeding various mills. All Engine computations were, of course, automated, updating every 2 minutes boiler efficiency, fuel flow, composite heating value and other performance parameters. At the time, the plant was running with seven mills, six of which had 8,100 to 8,500 Btu/lbm PRB coal with 30% moisture, and with a single mill with 11,000 to 12,500 Btu/lbm coal having

Figure 7: Input/Loss Response to Loss of Pulverizer Transient



less than 10% moisture. A low energy mill was lost, increasing the computed heating value of the composite fuel (based solely on CEMS data, etc.). The Engine's computed fuel flow, via Eq.(5), and the plant's "indicated" fuel flow are presented in Figure 7, as are boiler efficiency and computed composite heating value.

Table 3 shows typical ultimate analysis for the two types of coals used (the variations within each type could range from 5 to 10% in heating value). Also shown is a typical computed composite fuel chemistry and heating value produced from the Engine.

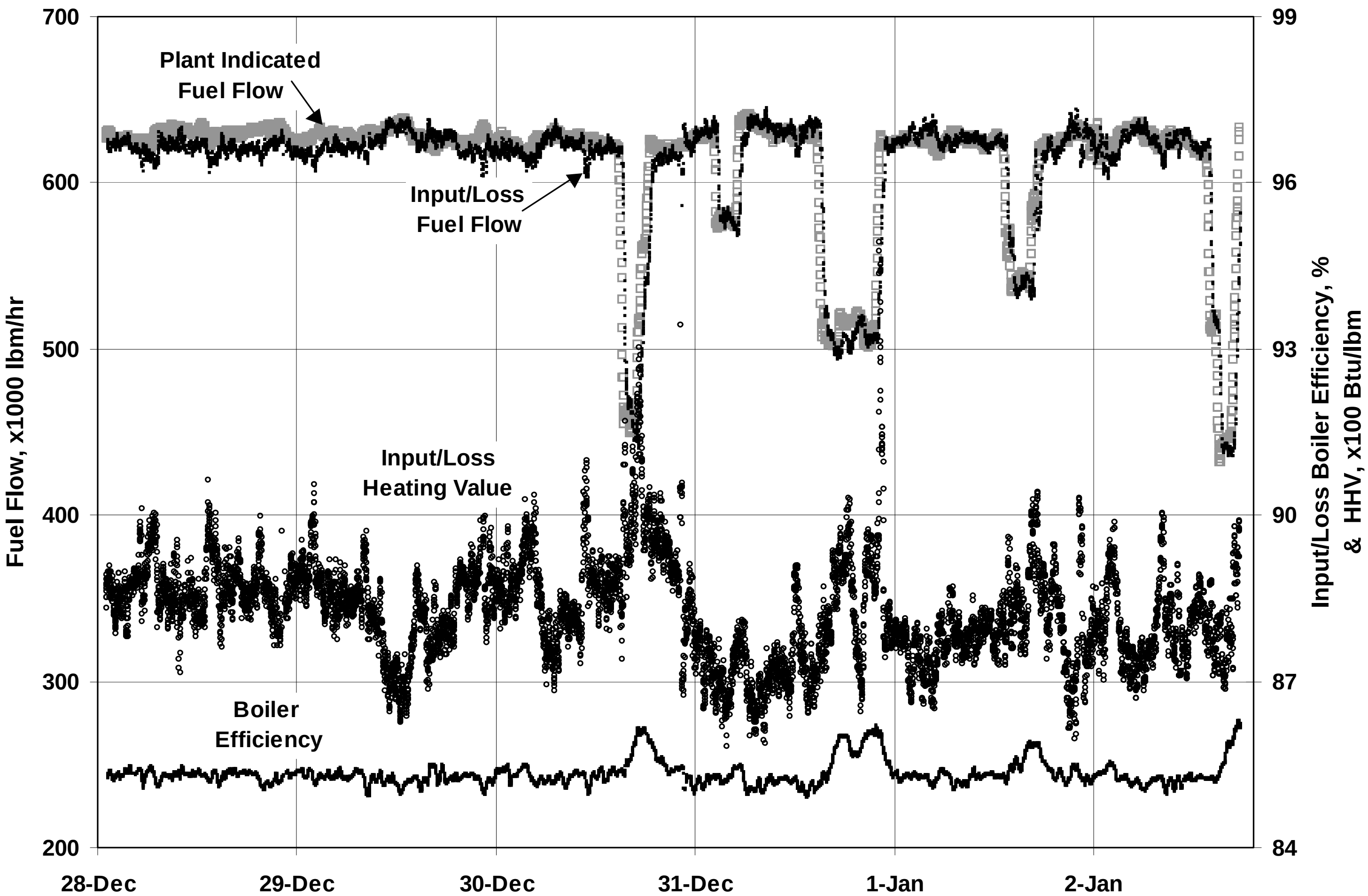
Further study of the Figure 7 shows a "lag" and then "lead" between the value of computed and plant's indicated coal flows. The Engine, after solving for fuel chemistry and heating value, computes fuel flow based on heat input to the working fluid; BBTC of Eq.(5). Such transient differences between calculated and indicated coal flows represents effects of the working fluid's stored energy. During a load decrease, the computed fuel flow is greater than the plant's indicated since the BBTC term "sees" effects from the stored energy in Deaerator and condenser (effects measured boundary conditions). Conversely during return to full power, calculated fuel flow is less than the indicated, caused by an incrementally higher flow actually being added to re-establish stored energies required of the loads.

Table 3: Coals Burned at Boardman

Fuel Chemistry:	Bear Canyon (lab. results)	Buckskin (lab. results)	Composite (Input/Loss)
Water	6.59	29.75	26.44
Carbon	64.56	49.32	51.50
Hydrogen	5.60	2.94	3.32
Nitrogen	1.36	0.37	0.51
Sulfur	0.63	0.43	0.46
Oxygen	7.76	12.23	11.60
Ash	13.50	4.96	6.17
HHV	11,695	8,360	8,837

The plant burned Bear Canyon and Buckskin coals, in various combinations, throughout 2001. By January 5, 2002 the plant burned the last of high energy Bear Canyon coal. Figure 8

Figure 8: Input/Loss Response to Changing Fuels

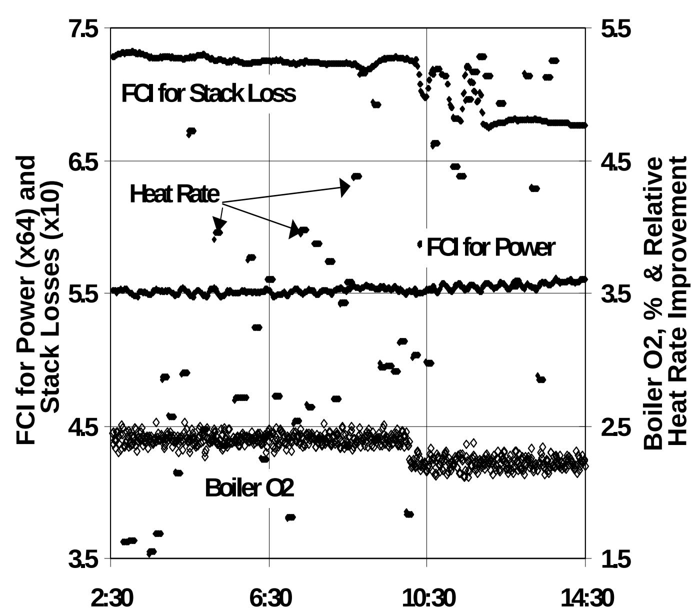


indicates the computed results during this transition; most r easonable results are again seen. Efficiency decreased typically 0.7% $\Delta\eta$. Although Figures 7 and 8 both employ an expanded heating value scale, they also demonstrate the volatile nature of mixing coals. For the days plotted in Figure 8, the mean change in heating value (before and after mid-night on the 30th) was 64 ΔBtu/lbm; however the standard deviation of all data was ±93 ΔBtu/lbm - typically a 200 ΔBtu/lbm range! Net heat rate during full load, steady state conditions changed from 9,820 to 9,876 Btu/kWh, or 56 ΔBtu/kWh degraded. Such information is valuable, as accurate and repeatable boiler efficiency computations, even with variable fuels, allows for consistent decisions.

EXAMPLE F: PULVERIZER PROBLEMS

On the November 14, 2001, the plant was forced to operate with six pulverizers. The plant maintained full load by configuring two mills with high energy Bear Canyon coal. Two of six mills running Bear Canyon implied 1/3 of the plant's fuel was high energy with low moisture. With this configuration, a higher than usual boiler efficiency was anticipated; however, Input/Loss computations indicated this was not the case.

Figure 9: Sensitivity to Changed O_2 Set Point



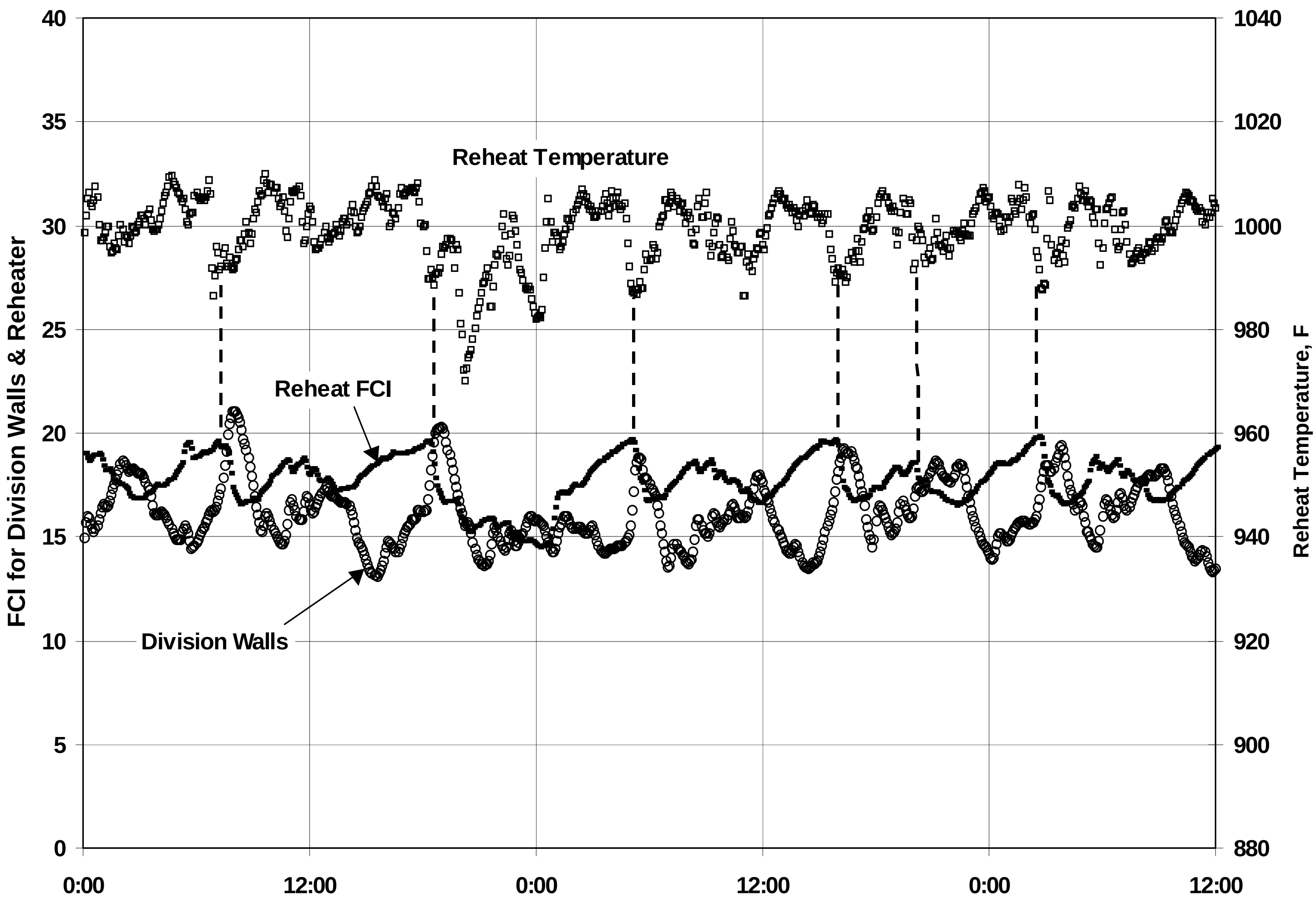
Boiler efficiency prior to the six mill configuration was approximately 85%. After two mills were bought on line with high energy coal, the computed boiler efficiency was essentially the same. Obviously something was wrong. Total air flow remained roughly the same, but with a lower computed fuel flow. Additionally, Stack CO_2 was approximately 11.67%, Stack O_2 at 6.0%. This data, with prior monitoring and testing experiences, indicated the plant was putting too much air into the plant. This was made evident by a variety of Engine performance parameters. Trusting in the boiler efficiency result (no change), operators lowered the O_2 set point from 2.50% to 2.20%. The effects of this were dramatic. Boiler efficiency increased to approximately 86%, while Stack CO_2 increased to approximately 12%, Stack O_2 decreased to between 5.5 and 5.6%. This data is presented in Figure 9.

Net heat rate decreased during this same period from 9,856 to 9,794 Btu/kWh, a 62 ΔBtu/kWh improvement. Another key performance parameter was the decrease in FCI for Stack Losses. Further, FCI_{Power} increased to around 355. However, of note was the increase in FCI for the Boiler. By decreasing air flow, more heat absorption takes place in the water walls of the Boiler, thus higher irreversible losses. The Boardman plant has a rather tall furnace, typical of plants designed for PRB coal, hence, a large relative heat absorption. Therefore, with lower air flow and larger heat absorption in this section of the furnace, higher irreversible losses would be expected. Again, this increase was offset both by a decrease in the FCI for Stack Losses and an increase in the important FCI_{Power}.

Conclusions reached included not to trust the Boiler O_2 probes given their sensitivity to the given mill configuration. With this mill configuration, Boiler O_2 was again inaccurately measured. This was made obvious by noting the increased Stack O_2 and decreased Stack CO_2 readings along with a greater than expected total air flow reading while maintaining the "same" Boiler O_2 set point. The implications of this error were quantified by noting boiler efficiency, unit heat rate, and the several FCIs being consistent with CEMS indications. Additional O_2 probes in the lower section of the Boiler flue were again justified by this experience.

A further conclusion reached, supported by other Input/Loss installations, is that on-line heat rate can offer extremely scattered data. This is seen in Figure 9, although the scale is greatly expanded to illustrate only the change in heat rate, ΔHR (from the start of the displayed data). However, similar observations has lead to the development of a "dynamic heat rate", which expresses with

Figure 10: Sensitivity to Soot Blowing



clarity to the operator which *direction his/her actions are causing on unit heat rate* - feedback tells the operator of an improvement or degradation (Lang, 2002b).

EXAMPLE G: FCI CHANGES WITH SOOT BLOWING

For plant operators, one of the recurring pursuits is the adequacy of soot blowing: Is the plant blowing too much or not enough? Figure 10 presents a plot of several FCIs for the boiler's major heat exchangers. Plotted are the FCI's for the Reheater and Division Wall Superheater, also plotted is final Reheat temperature. Soot Blower steam flow was not plotted as only system total use was recorded; soot blowing at Boardman is continuous. Note the periodicities of the FCI's and Reheat temperature. This clearly reflects soot blowing. The outstanding question is: Where in the steam generator is soot blowing occurring to cause such oscillations?

The next exchanger downstream from the furnace is the Division Walls followed by the Finishing Superheater. After the Finishing Superheater, combustion gases are split to the Reheater and the Primary Superheater/Upper Economizer heat exchangers (or back-pass); such split is governed through dampers as a function of final Reheat temperature. Damper controls are slow moving. As seen in Figure 10, losses in the Reheater are generally out of phase with losses (FCIs) in the Division Wall exchanger; although their peaks appear in-phase due to skewness (energy dissipation) in the Reheater. At these peaks (at the highest losses), Reheat temperature is minimized. When the Division Wall is blown, more heat is removed from the gas, followed by marked reduction in heat being delivered to the back-pass. This is confirmed by noting the drop in Reheat temperature. Second Law parameters suggest that removing soot from the Division Wall exchanger causes more heat to be absorbed in this heat exchanger, thereby causing a greater ΔT, thus higher irreversible losses hence an increase in the FCI for the Division Wall (as seen). Similarly, with less heat delivered to the back-pass exchangers, a reduction occurs in the ΔT across the tube surfaces reducing losses, thus a decrease in the FCI for the Reheater.

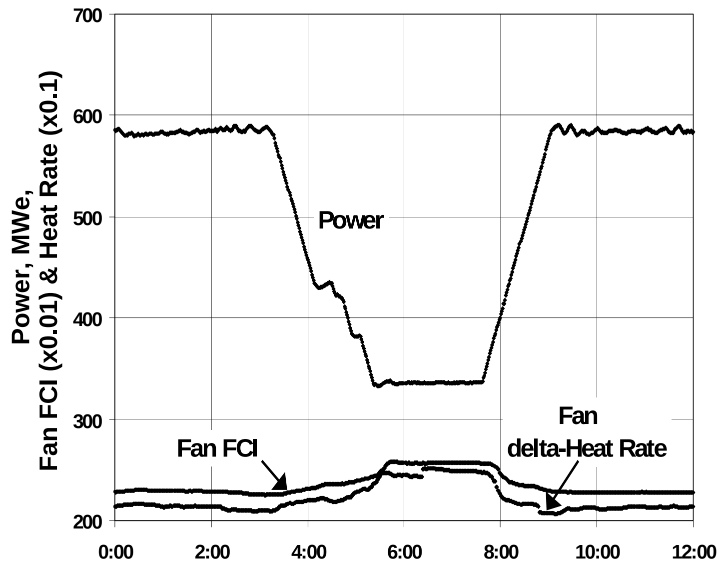
Note that minimal cyclic variation in the FCI for the Finishing Superheater was observed. Given this response, operators made the decision to reduce its soot blowing; thus a heat rate improvement. This action was over-checked by visual inspection and noting no appreciable change in the FCI pattern.

EXAMPLE H: INCREMENTAL HEAT RATE CHANGES

Boardman employs two Forced Draft Fans used for excess air and two Primary Air Fans for fuel transfer. Each fan uses its inlet vanes as a means to control: Forced Draft Fans control Boiler oxygen; and the Primary Air Fans control primary air duct pressure. Fans are run at full speed, throttling their vanes.

Figure 11 illustrates the sensitivity of irreversible losses incurred by the fans due to load changes. Figure 11 plots net heat rate, gross power, FCI for the Fan and its corresponding component heat rate for the Fans, hr_{Fan} . As shown in Figure 11, with a reduction in plant output, FCI for the Fan increases. As expected the fan continues to run at full speed with increased throttling due to reduced air demand. Of interest is the increase in the Fan's differential heat rate, hr_{Fan}, whose increases can be translated as a cost in fuel and power associated with load reduction of 5 ΔBtu/kWh is indicated.

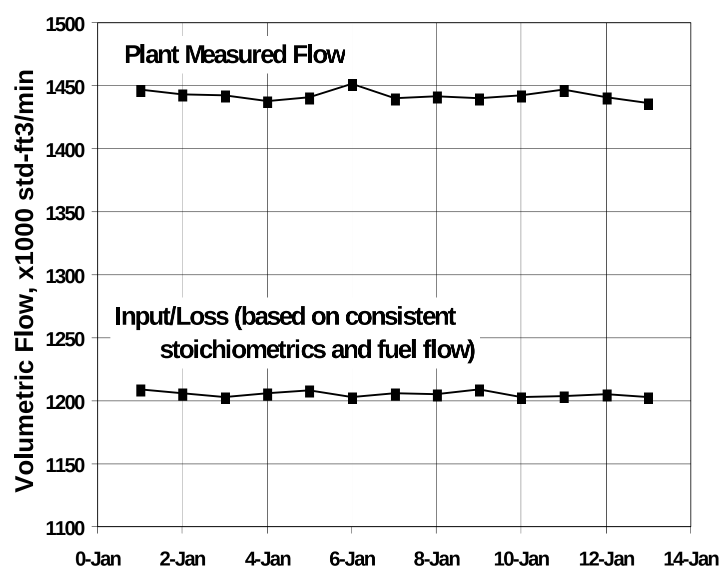
Figure 11: Fan Differential Heat Rate and FCI Changes to Load Reduction



EXAMPLE I: COMPARISON OF EFFLUENT FLOWS

A long-standing objective of Input/Loss technology has been to replace direct measurements of effluent flows, now practiced by the power industry, with computed flows based on consistent boiler efficiency, fuel flows and the same stoichiometrics as used to compute boiler efficiency; thus **consistent with unit heat rate**. Figure 12 illustrates Boardman's regulatory reported effluent flows (based on direct measurements) versus those computed by Input/Loss. Observed is a 16.4% difference. The measured is high - as has been observed and reported by others. These flows are volumetric rates using EPA defined standard conditions (of 68 F and 14.6959 psiA).

Figure 12: Measured and Computed Effluent Flows



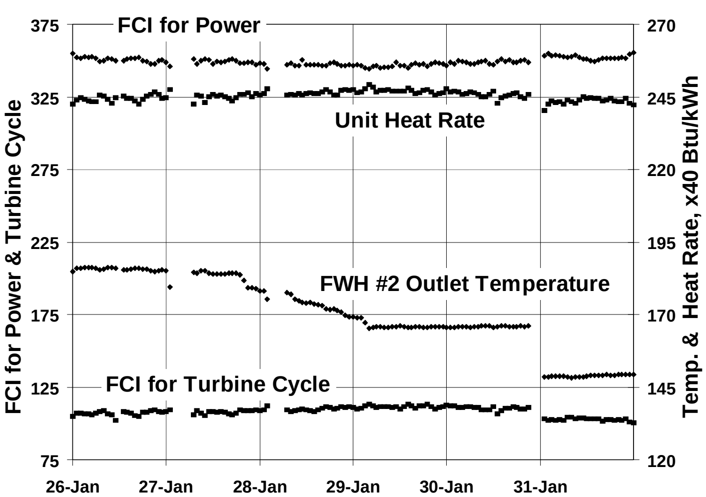
EXAMPLE J: TURBINE CYCLE EFFECTS

On January 27, 2002 the plant experienced difficulties with Feedwater Heater #2 (2nd lowest pressure heater). Plant personnel first noted Heater #2 level control problems which was immediately confirmed by an increasing FCI for the Turbine Cycle. Figure 13-14 illustrates a decreasing tube-side outlet temperature, tracked by a decreasing FCI_{Power}, an increasing FCI for the Turbine Cycle and degrading heat rate. This evidence lead to the heater's removal from service and investigative testing: all tubes were tested, drain and isolation valves were inspected, and vents were checked for blockage. Nothing was found. Three months later, during a minor outage, plant personnel opened the main condenser finding Heater #2 expansion joints were entirely missing! Evidently an expansion joint failed due to fatigue, resulting in its total destruction with debris critically damaging adjacent expansion joints. Indeed, all expansion joints in that section of the condenser were damaged including that for the Deaerator. The DA's protective shrouding was destroyed along with an expansion joint penetration. All was repaired, with Heater #2 extraction lines being sealed.

In Figure 13-14 note the consistency in FCI data, heater temperature data and heat rate. Daily averaged heat rate degraded from 9768 Btu/kWh on 1/26 to 9868 Btu/kWh on 1/29 (100 ΔBtu/kWh or 1.02%); FCI for Power degraded from 350.9 to 346.9 (1.14%), and FCI for the Turbine Cycle degraded from 106.7 to 111.4 (4.40%) over the same time - all consistency computed by the Performance Monitor. FCI for the Turbine Cycle clearly points to higher irreversible losses. Obviously, a feedwater heater failure leads to a degraded heat rate, but by isolating the #2 extraction its steam passes to the last stages of the LP turbine producing additional power. The effect between 1/26, before the failure and after repairs was a net 32 ΔBtu/kWh improvement.

What is noteworthy is how this failure was quantified both thermodynamically and financially. Although the problem was repaired during a short outage, in the future knowing the sensitivities of component FCIs, cost of heat rate degradation, cost of repairs and cost of lost generation, more logical decisions can be made as to investigation techniques and operational alternatives. Expansion joints will be replaced during Spring 2002 outage.

Figure 13-14: Heater #2 Failure (before & after)



CONCLUSIONS

Burning coal to produce power is a complicated process. If we as an industry are to monitor and improve electrical production using a minimum of fuel we must thoroughly understand the process. North America, and the world, is blessed with an abundance of coal. However, the power industry can not continue to assume that cheap fuel justifies cursory understanding. The pressures for improved boiler efficiency - given this represents an immediate reduction in emissions - come from throughout society, from regulators, from environmentalists and from the financial sector. Process understanding comes about by quantifying key performance parameters ... and dogged persistence. To act on this information, requires real time access to consistent, system-oriented information (not "data"), and a dedicated staff.

This paper has demonstrated some of the tools, and their sensitivities, which are now available to power plant engineers. At Boardman, we have improved boiler efficiency in a permanent fashion, and, more importantly, we have assisted operators by giving them the analytical tools for continuous feedback. The value to Boardman operators of having a consistent tool, as is the Input/Loss Method, has proven invaluable when coupled with testing and continual training.

ACKNOWLEDGMENTS

It is important to recognize the Boardman plant operators and its engineering staff for their outstanding contributions. Particularly helpful have been Marc Andreason, Randy Curtis, Dean Mason and Wayne Oren who implemented plant modifications, conducted testing projects, maintained a plant with 0.25% water loss, installed instrumentation and maintained the Performance Monitoring system - all leading to the improvements cited.

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