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DETECTION OF TUBE LEAKS AND THEIR LOCATION USING INPUT/LOSS METHODS

Fred D. Lang, P.E.
Exergetic Systems, Inc.
San Rafael, California 94901
Lang@ExergeticSystems.com

Dave A.T. Rodgers, P.E.
Portland General Electric
Boardman, Oregon 97818
Dave_Rodgers@pgn.com

Loren E. Mayer
Portland General Electric
Boardman, Oregon 97818
Loren_Mayer@pgn.com

ABSTRACT

This paper presents an on-line method which detects steam generator tube leaks and the heat exchanger in which the leak occurs. This method (the Tube Failure Model) has been demonstrated by direct testing experience. It is based on the Input/Loss Method, a patented method (1994-2004) which computes fuel chemistry, heating value and fuel flow by integrating effluent measurements (CEMS data) with thermodynamics. This paper explains the technology supporting the detection of tube failures, the method of identifying the location of the failure, and cites direct experience of detecting tube failures at two power plants. Most importantly, this paper presents the results of direct testing at the Boardman Coal Plant in which high energy steam/water lines were routed from the drain headers of all major heat exchangers into the combustion space. When allowed flow, these lines were used to emulate tube leaks from any of the major heat exchangers. Their flow rates and locations were then compared to Tube Failure Model predications.

This testing is considered significant as for the first time Δheat rate effects of tube failures will be directly determined; and, further, this testing will provide the Tube Failure Model its on-line proof-of-process.

NOMENCLATURE

a = Moles of combustion O_2 input to the system.
$a\beta$ = O_2 entering with air leakage; mole/base.
b_A = Moisture in the entering combustion air; moles/base.
$b_A\beta$ = Moisture entering with air leakage; mole/base.
b_T = Tube leakage; moles/base
b_Z = Water/steam in-leakage from working fluid; moles/base.
BBTC = Energy flow to the working fluid; Btu/hr.
C_j = Correction factor for a Choice Operating Parameter, e.g., C_{H2O} corrects the effluent moisture signal.
d_{Act} = Actual effluent CO_2 at the system's boundary; moles/base.
g = Effluent O_2 at the system's boundary, w/o leakage.
G_{Act} = Actual effluent oxygen at the system's boundary ($g + a\beta$).
HBC ≡ Firing Correction; Btu/lbm$_{AF}$.
HHVP = As-Fired higher heating value corrected for a constant pressure process; Btu/lbm$_{AF}$.
HR = System heat rate (HHV-based); Btu/kWh.
HPR_{Act} ≡ Enthalpy of Products, actual combustion; Btu/lbm$_{AF}$.
HRX_{Act} ≡ Enthalpy of Reactants, actual firing; Btu/lbm$_{AF}$.
j = Effluent water without moist air leakage; moles/base.
J_{Act} = Actual effluent water at boundary ($j + b_A\beta$); moles/base.
m_{AF} = As-Fired fuel flow computed by Input/Loss; lbm$_{AF}$/hr.
$m_{AF\text{-}PLT}$ = Plant indicated As-Fired fuel flow; lbm$_{AF}$/hr.
m_T = Tube leakage specific to an identified heat exchanger computed by Input/Loss; lbm$_{AF}$/hr.
N_k = Molecular weight of compound k.
R_{Act}= Ratio of moles of dry gas across the air heater, defined as the air heater <u>Leakage Factor</u>; molar ratio.
W_{output} = Gross power generated; kWe.
WF_{H2O} = Fraction of As-Fired fuel water; weight fraction.
x = Moles of As-fired fuel/base, $\sum n_i$ = 100 moles of dry gas product at the stack is the calc. "base"; moles/base.
α_k = As-Fired (wet-base) fuel constituent k per mole of fuel: $\sum\alpha_k = 1.0$, where k = 1,2, ...10.
β = Air heater <u>Dilution Factor</u>; molar ratio ≡ $100(R_{Act} - 1.0) / [a\, R_{Act} (1.0 + \varphi_{Act})]$
η_B = Boiler efficiency (HHV-based); unitless.
φ_{Act} = Molar ratio of non-oxygen gases (N_2 and Ar) to oxygen in the combustion air: $(1.0 - A_{Act}) / A_{Act}$.

BACKGROUND

Commercial coal-fired power plants having large heat exchangers are prone to tube leaks of their working fluid. These tube leaks represent a potential for serious physical damage to heat exchangers due to pipe whip (i.e., mechanical movement), and/or steam cutting of the affected and adjacent tubes given associated critical fluid velocities. When undetected for an extended time, the ultimate damage from serious tube failures may range from \$2 to \$10 million/leak for a commercial steam generator forcing the system down for major repairs lasting up to a week. In recovery boilers (used in the pulp and paper industry) tube leaks developing over minutes may lead to explosions via mixing water with molten smelt laden with sodium compounds.

If detected early, tube failures may be repaired before catastrophic damage, such repairs lasting only several days and costing a fraction of the cost associated with late detection and catastrophic damage. Repair times may be further reduced if the location of the heat exchanger which has the leak is identified before repairs are initiated.

Tube failures in steam generators are typically caused by one the following general categories (Cohen, 1989):

Metallurgical damage caused by hydrogen absorption in the metal resulting in either embrittlement or the formation of non-protective magnetite;
Caustic gouging caused by the presence of free hydroxide in the water;
Corrosion-fatigue damage caused from the water-side of the tube, compounded by stress;
Corrosion damage caused by impacts from solid ash particles;
Fatigue failure caused by oxidation and/or mechanical movement, compounded by stress;
Overheating (e.g., from tube blockage) causing local creep; and/or
Physical damage from steam cutting and/or mechanical movement associated with another failed tube in the same local.

There are several industrial methods used to detect tube leaks, none are considered by the authors to be reliable. The more common methods include: acoustic monitoring devices; water balance testing; and through the monitoring of effluent moisture using stack instrumentation. Acoustic devices rarely detect small to medium leaks (<20,000 lbm/hr), are expensive and require benchmarking with known acoustical signatures. Water balance testing is time consuming, insensitive to small leaks and typically may not be conducted at a sufficient frequency to prevent serious damage. Although an effluent moisture instrument can be sensitive to tube failures *per se*, such an instrument can not differentiate between originating and changing sources of water (e.g., between high and changing humidity in the combustion air, or changing fuel water, or changing fuel hydrogen, etc.).

INTRODUCTION

Effluent moisture from the system (at the stack) may consist of any of the following sources: water added at the point of combustion (e.g., steam used to atomize fuel); pollutant control processes resulting in a net flow to the combustion gases; soot blowing; water formed from the combustion of hydrocarbon fuels; free water born by the fuel; moisture carried by combustion air including air leakage; and, of course, heat exchanger tube leaks. Although all such terms effect system stoichiometrics, the resolution of a specific tube leakage, using Input/Loss, relies on establishing a so-called "Trip Mechanism" whereby the stoichiometric possibility of in-leakage is assessed.

After determining a Trip Mechanism and then computing a positive leakage flow, the Input/Loss Method's ability to detect the location of the failure works by assigning the tube leakage, in turn, to each of the major heat exchangers. For each of these separate analyses, certain "Key Comparative Parameters" are then examined (i.e., each analysis having been assigned the leakage flow) for deviations from reference values. That exchanger which yields a minimum deviation in its Key Comparative Parameters is the exchanger having the leaking tube.

The ability to detect tube leaks and their location is highly dependent on Input/Loss' ability to compute fuel chemistry on-line based on system stoichiometrics, and to corrected errors which may be present in any parameter effecting system stoichiometrics (Lang, 1998-2000). Parameters effecting system stoichiometrics include traditional CEMS data (e.g., stack CO_2, boiler or stack O_2, and generally stack H_2O), injected limestone, air heater leakage, O_2 in the ambient air, tube leaks, etc. These parameters are termed "Choice Operating Parameters" (COPs) and are fully described in the Input/Loss Part IV paper (Lang, 2004a). This paper explains how COPs are corrected such that consistent system stoichiometrics can then produce viable fuel chemistry and heating values; leading to a high accuracy η_B.

TUBE FAILURE MODEL DETAILS

Key to the detection of tube leaks is Input/Loss' integration of system stoichiometrics with thermodynamics (i.e., boiler efficiency and system-wide mass/energy balances). Such integration starts with a combustion equation. Eq.(19B) defines all system stoichiometric terms, including the use of the b_T term describing tube leakage. Eq.(19B)'s nomenclature is unique in that brackets are used for clarity: for example, the expression "$\alpha_2[H_2O]$" means the fuel moles of water, algebraically simply α_2; the expression "$d_{Act}[CO_2]$" means the effluent moles of carbon dioxide, algebraically simply d_{Act}. The stoichiometric base of Eq.(19B) is 100 moles of dry stack gas. Note that the symbol b_Z denotes the quantity of steam/water entering the combustion space which can be defined (measured flows such as soot blowing, atomizing steam, etc.). Such b_Z in-leakage is apart from water formed from combustion of hydrocarbon fuels, the term ($x\alpha_5$ + $x\alpha_9$); apart from free water born by the fuel ($x\alpha_2$); apart from moisture carried by the combustion air ($b_A + \beta b_A$); and apart from tube leakages (the b_T term).

$$
\begin{aligned}
x\big[\, & \alpha_1[N_2] + \alpha_2[H_2O] + \alpha_3[O_2] + \alpha_4[C] + \alpha_5[H_2] + \alpha_6[S] \\
& + \alpha_7[CO_2] + \alpha_8[CO] + \alpha_9[H_2S] + \alpha_{10}[Ash]\,\big]_{\text{As-Fired Fuel}} \\
& + b_Z[H_2O]_{\text{In-Leakage}} + b_T[H_2O]_{\text{Tube-Leakage}} \\
& + \big[(1.0+\beta)(a[O_2] + a\varphi_{Act}[N_2] + b_A[H_2O])\,\big]_{\text{Air}} \\
& = d_{Act}[CO_2] + g[O_2] + h[N_2] + j[H_2O] + k_{Act}[SO_2] \\
& \quad + \big[\, e_{Act}[CO] + f[H_2] + l[SO_3] + m[NO] + p[N_2O] \\
& \quad + q[NO_2] + t[C_{YP1}H_{ZP1}] + u[C_{YP2}H_{ZP2}]\,\big]_{\text{Minor Components}} \\
& \quad + x\alpha_{10}[ash] + v[C_{Refuse}] \\
& \quad + \big[\, \beta(a[O_2] + a\varphi_{Act}[N_2] + b_A[H_2O])\,\big]_{\text{Air Leakage}} \qquad (19B)
\end{aligned}
$$

In addition to the b_Z term, a term descriptive of tube leakage is added to the combustion equation, b_T, whose units are moles of water in-leakage per 100 moles of dry gas product. A hydrogen stoichiometric balance is used to resolve b_T. Upon this equation, and to other related relationships, limits testing is performed for tube failures. Such tests are termed Trip Mechanisms and provide an indication of possible tube failure and stoichiometric causality. Forming a hydrogen balance results in (20); note that effluent moisture is defined as: $J_{Act} \equiv j + \beta b_A$.

$$b_T = J_{Act} + f - x(\alpha_2 + \alpha_5 + \alpha_9) - b_Z - b_A(1.0 + \beta) \qquad (20)$$

Eq.(20) illustrates that for b_T to be positive, i.e., a leaking tube, that unique balance must be developed between the assumed (or measured) effluent moisture (J_{Act}) and the predominating negative terms: combustion water $x(\alpha_2 + \alpha_5 + \alpha_9)$, b_Z, and moisture in the combustion air and in the air leakage ($b_A + \beta b_A$). Eq.(20) clearly demonstrates that use of an effluent H_2O instrument, measuring J_{Act}, may not detect tube failures. For example, any unusual increase in J_{Act} could be caused by off-setting effects from high fuel water, high moisture in the combustion air, high air pre-heater leakage (a high β) and/or periodic soot blowing flow and/or use of atomizing steam (b_Z). Further, a tube leak could exist when the J_{Act} term is decreasing as caused, for example, by a large decrease in fuel water (when, at the same time, b_T is increasing). To resolve such difficulties, Eq.(20) must be used in conjunction with Input/Loss's computed fuel chemistry and correction techniques applied to COPs.

When Input/Loss computes fuel chemistry, such chemistry will include at least the determination of fuel elemental carbon (α_4 for coal), fuel elemental hydrogen (α_5 for coal) and fuel water (α_2). Input/Loss will determine such quantities, in part, based on Choice Operating Parameters including principal effluent concentrations (CO_2, O_2 and H_2O), combustion air psychrometrics (leading to b_A), and any water and steam flows used for soot blowing and atomizing of fuel (b_Z). Further, Input/Loss typically employs a correlation between moisture-ash-free (MAF) hydrogen and carbon, for example: $\alpha_{MAF-5} = A_5 + B_5\alpha_{MAF-4}$. Such a correlation establishes interdependency between fuel carbon and all principal effluents, and thus, through Eq.(20) and resolution of Eq.(19B), between the effluent concentrations CO_2, O_2 and H_2O, and the tube leakage term b_T. Given such interdependencies, it is most likely that when assuming $b_T = 0.0$, when in fact a tube is leaking, one or more fuel molar quantities (α_1, α_2, α_2, ...) will compute outside reasonability limits or even as negative values. Experience in using the Tube Failure Model has taught that fuel water will commonly compute as negative, even with a moderate leak when initially assuming $b_T = 0.0$ in Eq.(20).

In like manner, and especially for small leaks (when assuming $b_T = 0.0$), the fuel carbon and hydrogen terms could exceed reasonability limits; where, assuming that the constant B_5 is negative (which is typical for coals): $\alpha_{MAF-5} < \alpha_{MAF-5/min}$, and/or $\alpha_{MAF-4} > \alpha_{MAF-4/max}$. Such behavior when using Eq.(20), when first assuming $b_T = 0.0$ and then evaluating for reasonability limits, leads directly to an indication of a possible tube leakage. This process leads to a defined "Trip Mechanism", that is an indication of possible tube leakage has been found by applying stoichiometric considerations (min/max checks) ... further processing is called for to determine its validity and, if a valid leak, then to determine its flow rate and the location of the leak.

TABLE 1:
Sample of Tube Failure Mechanisms

ID	Trip Mech.	Comments
11	$J_{Act} < J_{Act/min}$	Effluent H_2O at the stack; a minimum J_{Act} is not likely.
12	$J_{Act} > J_{Act/max}$	Effluent H_2O at the stack.
21	$\alpha_{MAF-4} < \alpha_{MAF-4/min}$	MAF molar fraction fuel carbon; α_{MAF-4} is not a likely mechanism.
22	$\alpha_{MAF-4} > \alpha_{MAF-4/max}$	MAF molar fraction fuel carbon.
23	Negative sq. root	Resolution of fuel carbon (α_{MAF-4}) requires second order equation.
31	$\alpha_{MAF-5} < \alpha_{MAF-5/min}$	MAF molar fraction of hydrogen.
32	$\alpha_{MAF-5} > \alpha_{MAF-5/max}$	MAF molar fraction hydrogen; α_{MAF-5} is not a likely mechanism.
41	$\alpha_{MAF-2} < \alpha_{MAF-2/min}$	MAF molar fraction of fuel water.
42	$\alpha_{MAF-2} > \alpha_{MAF-2/max}$	MAF molar fraction of fuel water.
51	$WF_{H2O} < WF_{H2O/min}$	As-Fired wt. fraction of fuel water.
52	$WF_{H2O} > WF_{H2O/max}$	As-Fired wt. fraction of fuel water.
71	$C_{H2O} < C_{H2O/min}$	Correction factor for effluent H_2O.
72	$C_{H2O} > C_{H2O/max}$	Correction factor for effluent H_2O.
81	$C_{CO2} < C_{CO2/min}$	Correction factor for effluent CO_2.
82	$C_{CO2} > C_{CO2/max}$	Correction factor for effluent CO_2.

To further explain Trip Mechanisms, Table 1 presents some typical examples. Table 1 presents so-called "static mechanism; dynamic mechanisms are also checked which determine the rate of change of certain parameters (e.g., dC_{H2O}/dt). At present there are 35 Trip Mechanisms.

Experience of demonstrating the Tube Failure Model has indicated that making assumptions as to "apparently" impossible Trip Mechanisms is not advised. Thus both minimum and maximum Trip Mechanisms are all blindly tested when monitoring a fossil system. For example, a cursory evaluation would suggest that a high fuel water concentration (α_{MAF-2} or WF_{H2O} as computed by Input/Loss) would not indicate a tube failure given the mechanics of Eq.(20). However, if the thermal system experiences a small but steadily increasing tube leakage Input/Loss could steadily correct effluent water concentration upwards, causing tube failure mechanism ID #42 or #52; or water correction factors might exceed an upper bound causing tube failure mechanism ID #72 (see the Part IV paper as to the "how" of such situations). But also, unplanned scenarios of now Input/Loss is correcting effluent water and other Choice Operating Parameters could create unexpected Trip Mechanisms via complex stoichiometric relationships. Such considerations thus call for a blanket examination of all trip mechanisms.

TUBE LEAKAGE FLOW RATE COMPUTATIONS

The technique used for determining a tube leakage flow rate is accomplished in steps (termed "Passes"), employing a separative analysis technique. For Pass 1 and given an indicated Trip Mechanism: a tube leakage flow rate is determined by optimizing the Choice Operating Parameter for tube leakage flow, in combination with other Choice Operating Parameters except for effluent CO_2 and effluent water. Nominal correction factors to effluent CO_2 and effluent water are obtained from historical evidence. This achieves stoichiometric balance, resulting in an initial fuel chemistry and heating value assuming the nominally corrected effluent CO_2 and corrected effluent water are reasonable. For Pass 2 a final fuel chemistry and heating value are determined but this time as influenced by the determined tube leakage flow rate and all routine Choice Operating Parameters, except effluent water; that is, Choice Operating Parameters as would be routinely selected whose interdependencies are now effected by an established tube leakage. Pass 3 is a return to routine monitoring.

This separative analyses process was developed to address the situation where effluent water, based on either a measurement or an assumption, was being corrected without regard to how such a correction might influence other Choice Operating Parameters, especially tube leakage and the important effluent CO_2. For example, if in correcting a high effluent water signal (whose value reflects an actual tube failure) to a lower nominal value, the resultant Dry-based effluent CO_2 may become badly skewed effecting computed heating value. The preferred process first accepts the effluent water value using an historically based correction factor, $C_{H2O\text{-}Hist}$, i.e., not optimizing on effluent CO_2 and effluent water, but optimizing on tube leakage and all other Choice Operating Parameters. This optimization establishes a computed tube leakage flow rate, consistent fuel chemistry and a heating value given a tube leakage. The computed tube leakage could be essentially zero if determined to be stoichiometrically consistent. The process then repeats but including CO_2 and other Choice Operating Parameters, again except effluent water, and using the computed tube leakage flow rate ($m_T \geq 0.0$).

This separative analysis technique addresses several problem areas found during initial study: the marked insensitivity of small tube leakages on system stoichiometrics; correction factors being adversely influenced by an actual tube leakage, but the resulting effects of converged Choice Operating Parameters on stoichiometrics masking detection of tube leakage; shallow valley problems aggravated by tube failures; and statistical problems associated with scaling Choice Operating Parameters especially with widely varying tube leakage flow rates (e.g., from 2,000 to 100,000 lbm/hr).

In summary, after convergence of Pass 1, Pass 2 then re-establishes general system stoichiometrics via the previous selection of routine Choice Operating Parameters, but excluding effluent water (those effects are now said to be known as described by the computed tube leakage flow rate). In correcting Choice Operating Parameters during Pass 2, given m_T is now known, its molar equivalent is determined by Eq.(21). The effects of b_T being incorporated into system stoichiometrics through Eq.(19B).

$$b_T = m_T (x\, N_{AF}) / (N_{H2O}\, m_{AF}) \tag{21}$$

The b_T quantity, through balancing affects intrinsic with Eq.(19B), effects boiler efficiency, computed heating value, fuel flow and heat rate computations in the same manner as a b_Z quantity.

TUBE LEAKAGE LOCATION

Once a tube leakage flow rate has been determined, its impact on the total energy flow to the working fluid and on boiler efficiency may be determined; thus its effects on fuel flow and system heat rate may be understood. If a thermal system's feedwater flow is held essentially constant, then a developing tube leak will result in less total energy flow required from the combustion gases (and less generation). If the working fluid energy flow without tube leakage is termed BBTC, then the actual energy flow, assuming a tube leak, is given by: (BBTC - $m_T\Delta h$), where Δh is the enthalpy difference between the outlet of last heat exchanger effected by the leakage, h_{Last} (typically the Reheater), and the first exchanger so effected, h_{Leak} (i.e., the heat exchanger in which the leak occurs); $m_T\Delta h$ is the energy flow lost from the working fluid due to tube leakage. The enthalpy of the leaking fluid as it enters the combustion gas path, h_{Leak}, is assumed, by choice, to be the same as the heat exchanger's inlet enthalpy. When applied to the Input/Loss Method's of computing boiler efficiency, the enthalpy of the leaking fluid entering the combustion gas path must be properly referenced (thermodynamically); thus (h_{Leak} - $h_{f\text{-}Cal}$).

Quantitative effects on boiler efficiency and system heat rate have been found not to be obvious, and may not off-set. Computed As-Fired fuel flow and system heat rate are determined by the following, assuming a tube leak:

$$m_{AF} = (BBTC - m_T\Delta h) / [\, \eta_B\, (HHVP + HBC)] \tag{8}$$

$$HR = m_{AF}\, (HHVP + HBC) / W_{output} \tag{9}$$

$$= (BBTC - m_T\Delta h) / (\eta_B\, W_{output}) \tag{10}$$

It is important to recognize that the location of the tube failure effects the working fluid's energy flow. The typical steam generator used in the electric power industry routes the working fluid first through an economizer heat exchanger, then water walls, etc., and finally through a Reheater. If a tube leak occurs in an economizer, its loss is seen throughout the steam generator (having the greatest impact on working fluid energy flow, e.g., $\Delta h = h_{Reheat\text{-}outlet} - h_{Leak}$). If a tube leak occurs in the final Reheater, its loss only effects this last exchanger (having the least impact on working fluid energy flow and thus on computed fuel flow, $\Delta h = h_{Reheat\text{-}outlet} - h_{Reheat\text{-}inlet}$). This suggests that Eq.(8) has an unique solution dependent on the assigned (and actual) location of the tube leakage. When using The Input/Loss Method, such dependency on a location of the tube leak may be intrinsically a function of computed fuel chemistry and Firing Corrections, and thus, also a function of the resultant heating value and boiler efficiency.

Determination of the location of the tube leak is accomplished by recognizing that certain system parameters are a function of the working fluid mass and energy flows (as effected by tube failure flow rate and its location). One such system parameter is the computed fuel flow, m_{AF}, which is a function of ($BBTC - m_T\Delta h$) through Eq.(8). The system parameter of As-Fired fuel water fraction, WF_{H2O}, is a function of the ($BBTC - m_T\Delta h$) term through effects on boiler efficiency (η_B), heating value (HHVP), and Firing Corrections (HBC). Although not obvious, The Input/Loss Method, because it determines fuel chemistry, heating value, boiler efficiency and Firing Corrections independent of fuel flow, and with great consistency, must, never-the-less, effect computed boiler efficiency:

$$\eta_B = (BBTC - m_T\Delta h) / [m_{AF} (HHVP + HBC)] \tag{11A}$$
$$= (- HPR_{Act} + HRX_{Act}) / (HHVP + HBC) \tag{11B}$$

Eq.(11B) must reflect a consistently computed boiler efficiency - as computed by Input/Loss; just as Eq.(11A) as composed of a term which reflects the energy flow effected by tube failure location ($BBTC - m_T\Delta h$), and therefore reflects a consistently computed boiler efficiency.

The Enthalpy of Products and the Enthalpy of Reactants terms of Eq.(11B), HPR_{Act} and HRX_{Act}, are computed with terms influenced by both the tube leakage flow and its location. HPR_{Act} includes the enthalpy of all water exiting the system, relative to the enthalpy at their entry points into the combustion gas path; e.g., ($h_{Stack} - h_{Leak}$) for the tube leakage. HRX_{Act} includes the Firing Correction term which includes the entering enthalpy of all in-leakages of water including tube leaks, relative to a reference enthalpy taken as the saturated liquid enthalpy at the calorimetric temperature, that is: ($h_{Leak} - h_{f\text{-}Cal}$). Refer to the Part III paper for a detailed description of boiler efficiency (Lang, 2000), and to its supplement critiquing steam generator boiler efficiency standards (Lang, supplement, 2004b).

Determination of which heat exchanger has a tube leak is accomplished by assigning the tube leak to successive heat exchangers, in repetitive computations, and then examining Key Comparative Parameters produced from these computations for deviations from reference values. Reference values are determined from routine analysis, without tube leakage. For example, such Key Comparative Parameters include: the As-Fired fuel flow, the Fuel Consumption Index for heat exchanger j, the average fuel water fraction and heating value. The following weighings of these Key Comparative Parameters is typical in determining the lowest deviation:

$$\begin{aligned} \text{Deviation} = \; & 0.05\,(m_{AF\text{-}PLT} - m_{AF}) / m_{AF\text{-}PLT} \\ & + 0.55\,(FCI_{j\text{-}Ref} - FCI_j) / FCI_{j\text{-}Ref} \\ & + 0.25\,(WF_{H2O\text{-}Ref} - WF_{H2O}) / WF_{H2O\text{-}Ref} \\ & + 0.20\,(HHV_{Ref} - HHV) / HHV_{Ref} \end{aligned} \tag{12}$$

POWER PLANT EXPERIENCE

Early experience with a rudimentary Tube Failure Model at two power plants produced the results indicated in Table 2. These plants were a 700 MWe power plant burning high energy coal (Unit "A"), and a 600 MWe plant burning Powder River Basin coal (Unit "B"). Unit A did not use a stack moisture instrument, even though its ambient environment had considerable variation in humidity; it employed stack CO_2 and boiler O_2, stack moisture was input as a constant (then continuously corrected by Input/Loss). Unit B burned highly variable fuel; it employed CO_2, O_2 and H_2O all in the stack. For Unit B, which is not uncommon, every 40,000 lbm/hr of tube leakage is worth ≈1.0 to 0.6% $\Delta\eta_B$ depending on the location. The greatest penalty of a tube leak lies with the Economizer, the lowest in the Reheater.

TABLE 2:
Early Power Plant Experiences

Unit	First Notification	Action
700 MWe (Plt A)	Stoichiometric inconsistencies found during an Input/Loss installation (June 2001); added 50,000 lbm/hr leakage.	Tube leak repair to Rear Wall on July 28, 2001.
700 MWe (Plt A)	High stack moisture corrections, C_{H2O}, reported Jan. 2002; unit shutdown but found nothing; continued notices Feb.-Mar. 2002.	Tube leak repair to Steam Air Heater in mid-March 2002.
700 MWe (Plt A)	High stack moisture correction, C_{H2O}, reported by e-mail August 2002.	Repair to the Reheater on Sept. 29, 2002.
600 MWe (Plt B)	Tube Failure Model reported a 44,600 lbm/hr leak on Jan. 6, 2003; location in Primary SH (but w/o clear indication, Dev. < 20%); water drop test indicated a 40,000 lb/hr leak.	Tube leak repair to Primary SuperHeater on Jan. 8, 2003; see Figure 1.

Figure 1 represents a clear view as to the sensitivities afforded by the Input/Loss Method's ability to correct stack CO_2 and H_2O data. Shown are correction factors for the H_2O signal (lower curve, scaled), and the correction factor for the CO_2 signal (upper curve, scaled) resulting in Trip Mechanisms 71 and 82.

Upon a Pass 1 analysis, a tube leakage of 44,600 lbm/hr was computed. This leakage was predicted to be in the Primary SuperHeater but the model failed to draw a clear conclusion (i.e., based on the difference in "Deviations" of Eq.(12) between the lowest and next lowest exchangers, being less than 20%).

At the time, Plant B (Boardman) was being optimized using the L Factor, in combination with a programmed weak influence by the plant's indicated fuel flow. Examination of changes in boiler efficiency are subtle. For the actual plant condition (employing a Boiler-Follow-Turbine control mode), and although boiler efficiency is varying, the difference between maximum and minimum efficiency was observed at 0.8% $\Delta\eta_B$ (before vs. after repair), considered in reasonable agreement with sensitivity studies for a predicted leakage of 44,600 lbm/hr found in the Primary SuperHeater.

A third plant, Plant C, having an installed Input/Loss Method was found to have a tube leak. This finding was notable in that the plant chose not to repair the leakage for a period of three months. Later cost estimates, in lost fuel and power, given the predicted leakage flow, exceeded $5 million.

To demonstrate the sensitivity of Eq.(12), without use of the Fuel Consumption Indices (FCI), Table 3 presents results from a calculational tube leak located in an economizer. Note that Eq.(12) as presented, using FCIs, is believed to have greater sensitivity than indicated in Table 3.. Application of the Tube Failure Model resulted in determining the tube failure flow rate of 100,169 lb/hr, and identifying the location of the failed tube in the system's economizer since it had the lowest analyzed deviation as seen in Table 3.

SPECIALIZED TESTING AT BOARDMAN

To further prove the Tube Failure Model an ambitious testing program at Boardman was begun in September 2003. Boardman is a 600 MWe unit burning Powder River Basin coal. The test at Boardman involved running high energy piping from the drain headers of many of the major heat exchangers to the combustion space, thus emulating tube failures with identifiable locations. Pressure, temperature and flow instrumentation was installed, as were flow restricting devices at pipe discharges. Although problems were had with the instrumentation and discharge nozzles, causing long delays, solutions were eventually found.

Initial findings from this testing were both spectacular and discouraging. At Boardman two parallel gas ducts carry combustion gases through two electrostatic precipitators, to two ID fans, to the stack (having a physical bifurcation in its entrance region). The stack exit has demonstratable separation of gas plumes. Of interest stoichiometrically is that the stack moisture instrument detects (using a narrow band-pass IR instrument) perpendicularly across both plumes; two O_2 probes measure individual plumes. However, the CO_2 probe is placed at the boundary between plumes (and sensitive to ID fan bias).

Given general frustration at instrumentation delays, it was decided to emulate a tube failure by eliminating the metered soot blowing flow from Input/Loss' input (thus $b_Z = 0.0$, with the Tube Failure Model engaged). A routine, and uniform, soot blowing pattern was established during night operation of September 10, 2003. Spectacular results were had as seen in Figure 2. Figure 2 is a most striking example of the sensitivity afforded by Input/Loss, the integration of effluents with thermodynamics: bear in mind that the "tube leakage" flow was computed based on system stoichiometrics, with corrected Choice Operating Parameters, with computed fuel chemistry, with computed heating values, with computed boiler efficiency, all leading to fuel flow ... such that a 0.1% sensitivity to feedwater flow is possible.

Knowing that Boardman's stack gases tend to remain bifurcated, the following night it was decided to alter the soot blowing flow to test general sensitivity of the CEMS instrumentation. Note that with bifurcated plumes, the sensitivity of the CEMS CO_2 probe depends on the (arbitrary) bias to the ID fans. Such sensitivity was accomplished by biasing the soot blowing schedule such that each plume would be favored with a supposedly higher moisture content, with concomitant changes to effluent CO_2 and O_2. Results are seen in Figure 3 ... they are both spectacular and discouraging. The Input/Loss Method produced essentially no "tube leakage" flow during the first four hours, but then computed ≈double the metered flow during the second four hours. We have no stoichiometric explanation why the flow was computed higher. There was no discernable change in the stack CO_2 and O_2 data, nor in stack H_2O data.

Recognizing that the CEMS CO_2 instrument was not adequate for the sensitivity demonstrated by Input/Loss, a new CO_2 instrument was acquired to measure perpendicularly across both plumes, in the same fashion as the stack moisture instrument. Testing was then repeated in early March 2004 with outstanding results. March testing demonstrated that, indeed, correct measurement of effluent CO_2 produced no differences when soot blowers are biased; see Figures 4 and 5.

After success with emulating tube failures using soot blowing steam, the original testing of major heat exchangers became almost commonplace. Four heat exchangers were still tested, yielding outstanding results (as would now be expected). Results are presented in Table 4. This testing produced the **first directly measured effects of tube leakage on boiler efficiency**.

CONCLUSIONS

A clear conclusion was the unexpectedly high sensitivity demonstrated by Input/Loss; demonstrable at a level approaching 0.1% of feedwater flow. Another conclusion is that the Tube Failure Model, and the Input/Loss Method in general, must pay attention to how gas plumes are mixed - without complete mixing, detecting tube failures will be dependent on the location of the failed tube and its peculiar influences on stoichiometrics.

The ability of the Input/Loss Method to detect tube leaks has been demonstrated by unambiguous experiences at two power plants, in addition to direct and dramatic proof-of-process testing at Boardman. Its ability to predict the location of the heat exchanger containing the failed tube has also been demonstrated.

The impact of tube leakage on thermal performance is dependent on the location of the leak: approximately 1.0% decrease in boiler efficiency ($\Delta\eta_B$) can be expected for every

40,000 lbm/hr leakage from an Economizer; while 0.5% decrease can be expected with a Reheater tube leak. Tube leakage will always degrade boiler efficiency. However, the impact of tube failures on an "observed" unit heat rate is ambiguous. If controlling in a "boiler-follow-turbine" mode, increases in fuel and feedwater flows to produce a constant power may not be observed (and especially in a coal-fired plant); and the effect of a computed tube leakage on working fluid energy flows would require an Input/Loss approach.

It is becoming apparent that tube leakage represents a major source of unrecognized boiler efficiency degradation. Reasons for prior unrecognized degradation arise from not having a viable method to detect tube failures, nor to accurately predict their flow rates. Input/Loss offers a solution.

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TABLE 3: Example of the Sensitivities Using a Modification of Eq.(12)
(a simulated leakage of 100,000 lbm/hr placed in the Economizer)

Heat Exchanger	% Dev. per Eq.(12)	m_{AF} (lb/hr)	WF_{H2O} (fraction)	WF_{Carbon} (fraction)	HHV (Btu/lb)	m_T (lb/hr)
Reference Data:	---	484655	6.7854	69.8391	12406.10	0
Economizer	0.5856	484343	6.7337	69.8779	12412.90	100169
Water Walls	1.7508	483912	6.9401	69.7233	12385.50	98788
Primary SH	9.3283	484570	7.6132	69.2190	12295.90	94701
Primary Sec. SH	11.9633	484512	7.8470	69.0438	12264.80	93224
Final Sec. SH	12.3274	484066	7.8789	69.0199	12260.50	92939
Reheat	9.5705	484144	7.6343	69.2032	12293.10	94486

TABLE 4: Summary Results of Tube Failure Testing at Boardman

Heat Exchanger	Measured Leakage (lbm/hr)	Input/Loss Leakage (lbm/hr)	Input/Loss Predicted Location	**Effect on Boiler Efficiency (% $\Delta\eta_B$ per 40,000 lb/hr Leakage)** *	Comments on Determination of Location
Lower Economizer	19,688	19,300	Lower Econ	**1.071**	Strong indication of location.
Upper Economizer	18,237	12,718	Upper Econ	**[0.723]**	Weak indication of location.
Primary Superheater	n/a	n/a	n/a	**[0.786]**	Calculated effect.
Division Walls	34,265	31,717	Div. Walls	**[no reference]**	Strong indication of location.
Soot Blowing (avg)	12,311	13,646	Final SH	**[0.694]**	Source between Div. & Final SH.
Final Superheater	n/a	n/a	n/a	**[0.694]**	Calculated effect.
Reheater	3,540	7,248	Reheater	**0.533**	Strong location. Erroneous flow.

* [Bracketed] effects indicate computed values using EX-FOSS; others are As-Tested as presented with high confidence.

FIGURE 1:
Tube Failure at Boardman, January 2003

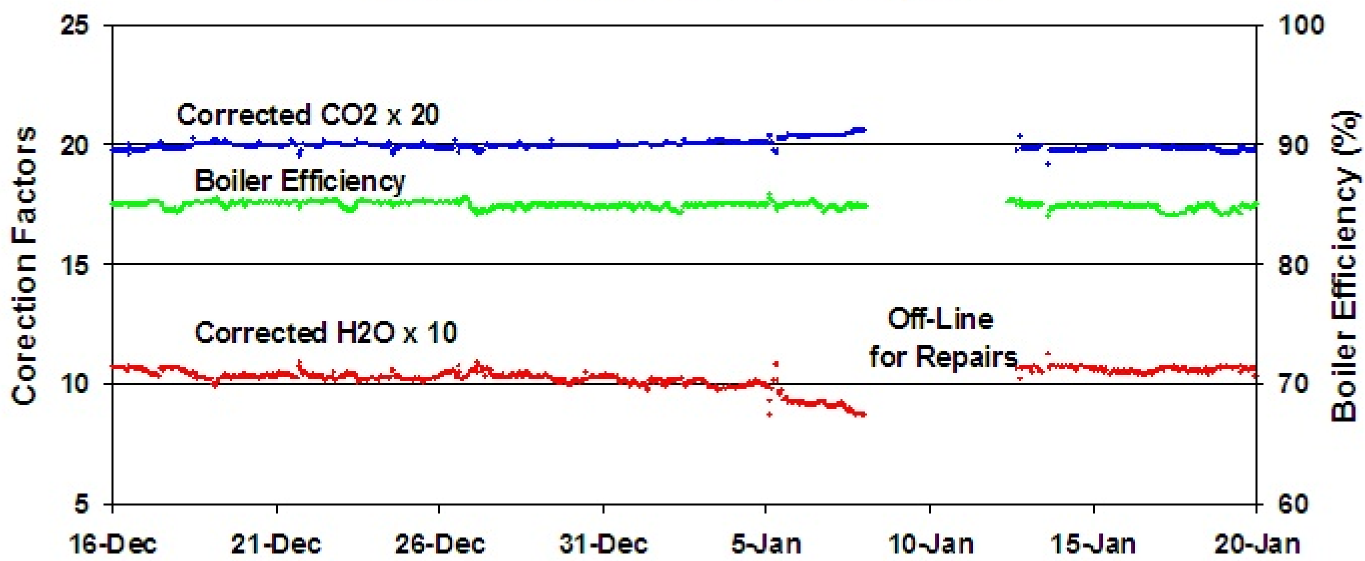

FIGURE 2:
Tube Failure Testing at Boardman:
Emulation by Soot Blowing, Uniform Flow Pattern, Sept. 10, 2003

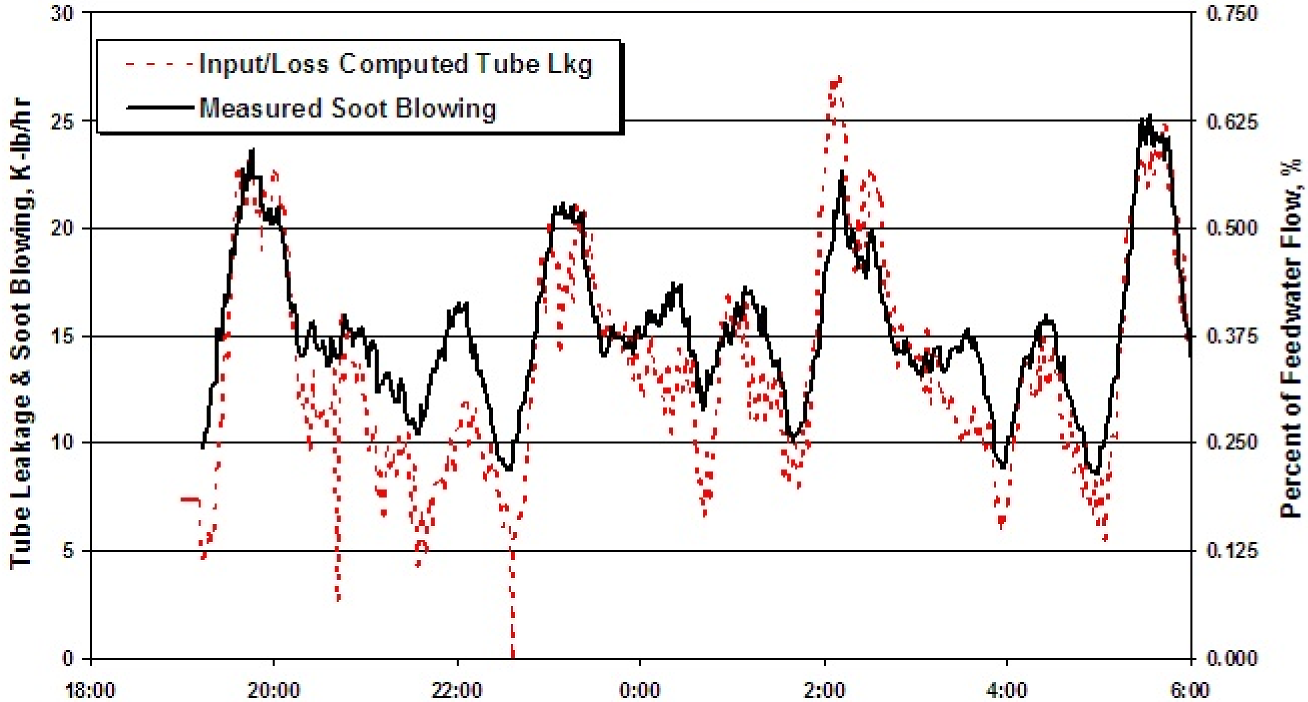

FIGURE 3:
Tube Failure Testing at Boardman:
Emulation by Soot Blowing, Biased Flow Pattern, Sept. 11, 2003

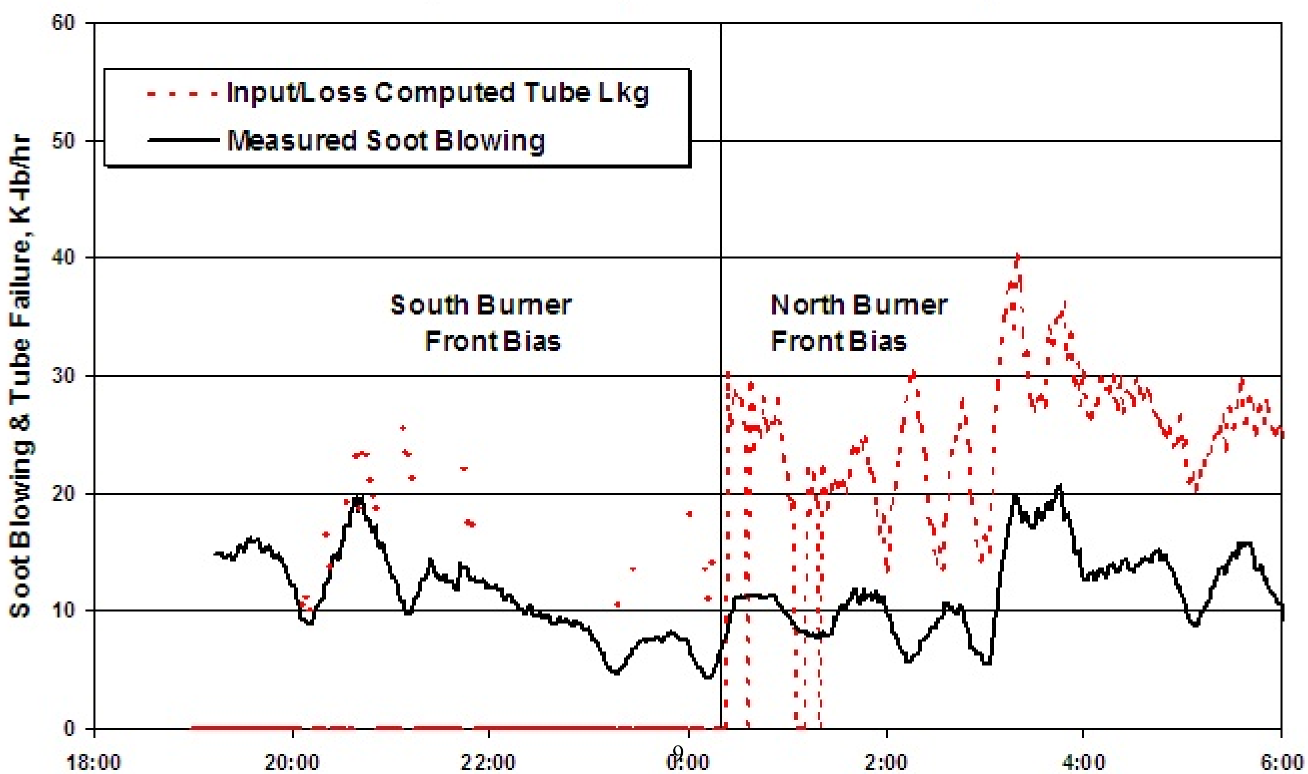

FIGURE 4:
Tube Failure Testing at Boardman:
Emulation by Soot Blowing, Uniform Flow Pattern, March 2, 2004

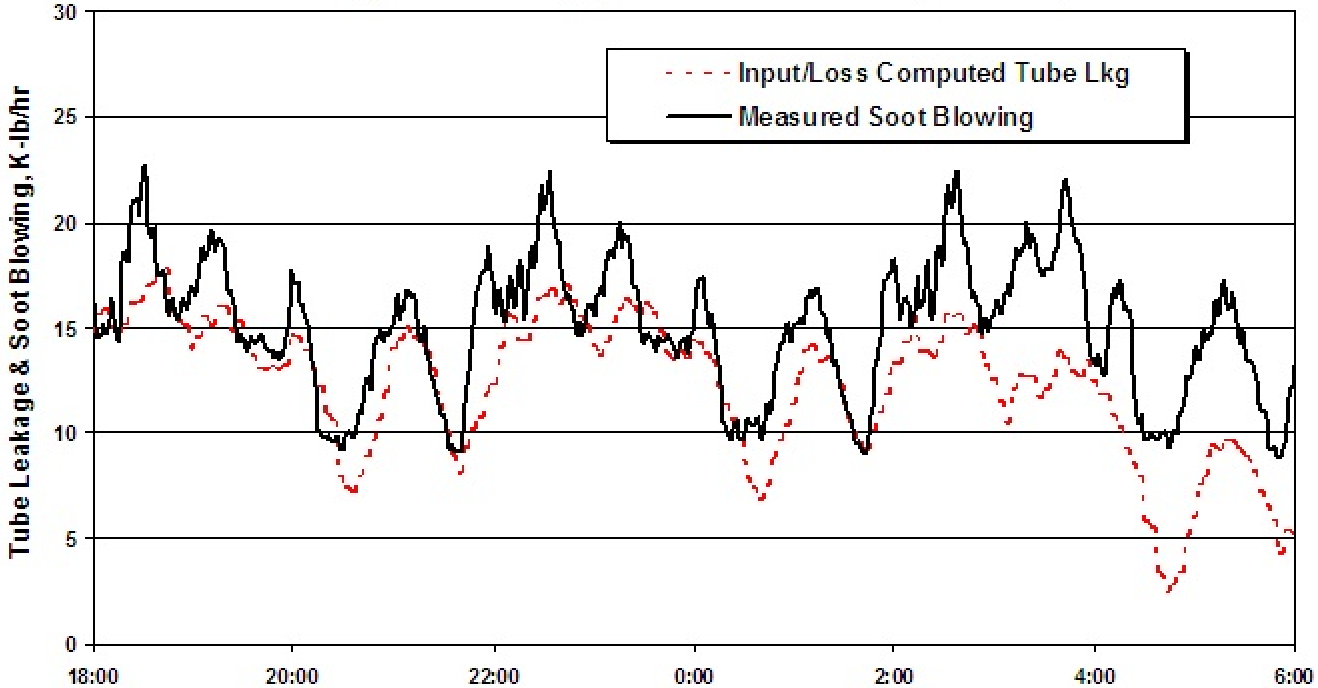

FIGURE 5:
Tube Failure Testing at Boardman:
Emulation by Soot Blowing, Biased Flow Pattern, March 3, 2004