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VERIFIED KNOWLEDGE OF YOUR FOSSIL-FIRED POWER PLANT

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ABSTRACT

The electric power industry has seen many decades of attempts to monitor their fossil-fired units for thermal performance; that is, monitoring techniques which aid the operator in understanding the system's thermal efficiency and, with that understanding, to direct improvements in thermal efficiency and reduction of emissions. These include the early efforts by JK Salisbury in the 1950s, to incremental heat rate approaches, to fault tree analyses, to fuzzy logic, to "artificial intelligence", etc. One can divide all such methods into two broad categories: those methods which argue for absolutes and those which stress that only relative indications suffice. The "absolute" camp will compute boiler efficiency based on principles established by ASME Performance Test Code 4[1] (or the older 4.1), and/or on the European standard.[2] The "relative" camp believes that hour-over-hour improvements can be achieved by monitoring selective parameters - examining their relative changes over brief periods of time. It is the author's option that both methods have serious flaws. This paper argues for a third approach, the Input/Loss Method, relying on absolutes which after verification may then be coupled to relative heuristics. But, note well, the Input/Loss Method because of its potential for high absolute accuracy is intrinsically verifiable - results can and must be proven. Simple switches are activated by the operator which allow Input/Loss to back-calculate the use of soot blowing steam flow, fuel flow, ambient relative humidity and/or track the Boiler Master signal. With such demonstrated accuracy, only then can one allow analysis of plant parameters - via direct operator instructions and/or automated signals.

This paper briefly discusses prior techniques, their fundamental concepts and deficiencies. The paper then explains the framework of Input/Loss a product offered by Exergetic Systems. Central to Input/Loss is the proposition which is basic to any thermal performance technique, and, indeed, basic to any real world engineering:

INDEPENDENTLY VERIFY RESULTS.

This is the key to the Input/Loss Method.

This paper presents actual test data which demonstrate verified plant understand based on the Input/Loss Method. Input/Loss is a patented technique which produces fuel chemistry, fuel calorific value, fuel mass flows, complete system mass/energy balances and other performance information in real-time. Computations are based principally on integrating corrected emission measurements with thermodynamic principles. The key is a computation of a high accuracy boiler efficiency ... one based only on corrected stack emissions (CO_2, O_2, H_2O and minor pollutants), and routine working fluid and plant data. Fuel, air and combustion gas mass flows are not input. Four very different verification techniques are presented: back-calculating soot blowing flow and comparison to the directly measured; back-calculated combustion air humidity and comparison to ambient; predicting boiler-master signals; and a computed fuel mass flow and comparison to the plant's direct measurement.

NOMENCLATURE

Stoichiometric Terms

a = Moles of combustion O_2 input to the system per stoichiometric base; moles/base.
aβ = O_2 entering with air leakage; moles/base.
A_{Act} = Molar concentration of O_2 in dry ambient air local to the system; NASA standard is 0.20948.
b_A = Moisture entering with combustion air; moles/base.
$b_A\beta$ = Moisture entering with air leakage; moles/base.
b_T = Water/steam in-leakage from tube leakage; moles/base.
b_Z = Water/steam measured in-leakage (e.g., soot blowing); moles/base.
d_{Act} = Total effluent CO_2 at boundary; moles/base.
g = Effluent oxygen without air leakage; moles/base.
G_{Act} = Total effluent O_2 at boundary; moles/base.
j = Effluent water without air leakage; moles/base.
J_{Act} =Total effluent water at boundary; moles/base.
N_k = Molecular weight of compound k.
R_{Act} = Ratio of moles of dry gas before entering the Air Pre-Heater to gas leaving, the Leakage Factor.
x = As-fired fuel moles per the base of 100 moles of dry gas product; moles/base.
α_k = As-Fired (wet-base) fuel constituent k; moles-k/mole fuel.
β = Air Pre-Heater Dilution Factor (ratio of air leakage to true combustion air); molar ratio.
= $100(R_{Act} - 1.0) / [a\, R_{Act}\, (1.0 + \varphi_{Act})]$
Λ_i = Choice Operating Parameter for quantity i.
φ_{Act} = Ratio of non-oxygen gases (N_2 and Ar) to O_2 in combustion air $(1.0 - A_{Act})/A_{Act}$; molar ratio.

Quantities Related to System Terms

A & B [=] Scaling constants for Eqs.(7) & (8).
HBC ≡ Firing Correction, fluid sensible heats referenced to calorimetric conditions; ΔkJ/kg_{AF}.
HHV_{AF} = Gross calorific (heating) value of the fuel determined by laboratory calorimetry for coal and oil, computed for natural gas, establishes the calorimetric (reference) temperature; kJ/kg.
HHVP = As-Fired gross (higher) heating value, constant pressure corrected from HHV_{AF}; kJ/kg_{AF}.
H_{Amb} = Relative humidity of ambient air; fraction.
L_{10} = Mass ratio of ideal dry effluents to Moisture-Ash-Free fuel, see US Patent 7,328,132.
LHVP = As-Fired net (lower) heating value, corrected for constant pressure from HHV_{AF}; kJ/kg_{AF}.
m_{AF} = As-Fired fuel mass flow rate, kg/hr.
m_T = Mass flow of water/steam associated with tube leaks, kg/hr.
m_Z = Mass flow of water/steam as-measured in-leakage (e.g., soot blowing), kg/hr.
P_{Amb} = Pressure of ambient air, BarA
$\sum Q_{WF}$ = Working fluid useful energy flow; kJ/hr.
$T_{Dry\text{-}Bulb}$ = Dry Bulb temperature of ambient air, ^oC.
$\eta_{B\text{-}HHV}$ = Boiler efficiency on a gross (higher heating value) bases, unitless.
$\eta_{B\text{-}LHV}$ = Boiler efficiency on a net (lower heating value) bases, unitless.
$\boldsymbol{\mu}_{corr\text{-}k}$ = Correction factor for emission measurement k, unitless.
ω_{Air} =Ambient specific humidity, $f(P_{Amb}, T_{Dry\text{-}Bulb}, H_{Amb})$, kg-$H_2O$/kg-Dry-Air.

Subscripts and Abbreviations

Act = An actual value (and typically directly measured).
AF = As-Fired fuel (wet with mineral matter).
Amb = Ambient conditions at boundary of system.
Meas = Measured, uncorrected signal.

INTRODUCTION

If computing boiler efficiency - an assumed absolute - historically there are two approaches: the Input/Output Method and the Heat Loss Method. The Input/Output Method is simple: directly measure the fuel flow; "assume" one knows the fuel's energy content; measure the useful output; and thus boiler efficiency is "Output / Input":

$$\eta_{B\text{-}HHV} = \sum Q_{WF} / [m_{AF} (HHVP + HBC)] \qquad (1A)$$
$$\eta_{B\text{-}LHV} = \sum Q_{WF} / [m_{AF} (LHVP + HBC)] \qquad (1B)$$

In many decades of practicing thermal performance engineering this author has observed, only but a few coal-fired users of Input/Output which have demonstrated by test the validity of their measured fuel flow. The vast majority of Input/Output results yield nothing more than relative indications.

This author has tested over two dozen of the natural gas-fired units operated by San Diego Gas & Electric, Southern California Edison and Pacific Gas & Electric along the California coast. Although Input/Output results for these gas units can be believed given accurate gas metering, each plant also computes efficiency using the Heat Loss Method for important component information. For natural gas-fired and oil-fired units, where fuel flow and composite calorific value (at least for gas) can be accurately measured in real-time, the problem still remains that the performance engineer has no information on the system components. If the gross unit heat rate is degraded, where does the engineer look? Calorific values for oil-fired units can vary substantially. For coal-fired units believing in un-verified measurement of fuel flow is a fool's errand. Many North American and Western European coal-fired operators might believe their gravimetric feeders are viable for performance engineering. Typically however, we observe errors in the 5 to 10% range. Yes, there are exceptions. But let's assume the ideal: presume a load-following coal-fired unit in which their gravimetric feeders are ideally calibrated at four load points every week (remember, feeders are non-linear). Assume that the resulting variance in flows at each load point over a three month period is <0.25%. Although this might be considered fantasy, problems still remain: verify the fuel flow (is the indicated average and its variance real?); demonstrate the assumed calorimetric value ... and we still have no component information. If a coal-fired unit is using Input/Output without verification nor subsequent analyses, there is little true regard for thermal performance.

The Heat Loss Method is the only method specified by the industrial standards.[1,2] Implementations in their details differ for each standard and their daughter standards, but fundamentals are the same:

$$\eta_{B\text{-}HHV} = 1.0 - [\Sigma\ \text{Losses}]/[m_{AF} (HHVP + HBC)] \qquad (2A)$$
$$\eta_{B\text{-}LHV} = 1.0 - [\Sigma\ \text{Losses}]/[m_{AF} (LHVP + HBC)] \qquad (2B)$$

Assumed by Heat Loss is that system thermodynamic losses (with only slight dependency on fuel flow) can be computed with accuracy. Although accurate fuel flow is not required, Heat Loss does require critically important inputs: fuel chemistry (an ultimate analysis); fuel calorific value; and parameters affecting losses. There is no standard which requires the user to prove the validity of results. Heat Loss standards are significantly flawed for a number of reasons as has been documented;[3-5] in summary, prime failures include:

- Failure to use a consistent reference temperature for As-Fired fuel, combustion gases, combustion air, in-leakages, sorbent injections and working fluid. The only valid reference temperature is that which was established for fuel calorimetrics. We cannot burn fuel whose HHV_{AF} was determined at 30 ^{o}C, using air at 15 ^{o}C with 90% humidity (using dry gases at one reference, moisture at another), combustion gases referenced at 25 ^{o}C, in-leakage of water referenced to 0.01 ^{o}C ... and hope to hell the First Law is conserved. Errors typically range from 0.5 to >2.0% depending on differences: calorimetric versus the gases' reference, calorimetric versus the air's reference; etc.
- Failure to compute the major [Σ Losses] term, Stack Loss, with accuracy. It must be computed on absolutely consistent fuel chemistry and resultant system stoichiometrics; never on an ultimate analysis which was assumed without verification.
- Failure when allowing coal pulverizer shaft power to affect boiler efficiency.

- Failure to allow for a variable φ_{Act} term (ratio of non-oxygen gases to O_2 in combustion air), having great sensitivity on boiler efficiency; appearing in all combustion equations, see Eq.(3).
- Failure to consistently apply system stoichiometrics; again, only with a known fuel chemistry (i.e., an ultimate analysis) can we then compute fuel, combustion air and gas mass flows perfectly consistent; this is not addressed by any standard.
- Failure to demand a back-calculated fuel mass flow.
- Failure to provide verification procedures: compare the computed fuel flow with the measured (applying judgment); trend over time a computed Boiler Master signal based on the computed mass flow and fuel chemistry versus plant data; compare a computed soot blowing steam flow based on system stoichiometrics with plant data; etc.

Little positive can be said for the relative indications. These techniques evolved simply because industry learned not to believe traditional Heat Loss results. Fault tree analysis never had enough intelligent branches. Soft statistical methods have become notorious for their ill-logic: they would "learn" to increase air/fuel ratios to reduce NO_X emissions; they would "learn" to reduce power to lower emissions; etc. The author believes the relative approaches could have merit provided they are based on verifiable system understandings. None are. Incremental heat rates produced from these methods never summed to a believable unit heat rate. Such systems had no life beyond 1 to 2 years - operators simply turned them off. It is for these reasons that on-line monitoring systems in North America and Europe have suffered for years from poor reputations.

INPUT/LOSS METHOD

The Input/Loss Method addresses all of these issues, and more. Although "verification" of monitored results is the subject of this paper, Input/Loss computes in real-time As-Fired fuel chemistry, As-Fuel calorific value and fuel mass flow all based on emission concentrations found the stack: CO2, O2 and H2O. It employs an iterative procedure by correcting these emission concentrations by optimizing differences found in a certain L10 Factor - descriptive of generic fuel types (anthracite, Powder River Basin, sub-bituminous, peat, lignite, etc.) - with corrected emissions; fuel chemistry is then computed; with chemistry a differential calorific value is computed; with these and system parameters, boiler efficiency is then computed ... and thus begins an iterative process until convergence is had. No fuel, air or gas flows are ever used for the boiler efficiency computation; they are outputs.

The origins of Input/Loss employs the most base philosophies of both the Input/Output Method (understand the system, concentrate on fuel flow), and the Heat Loss Method (compute an accurate boiler efficiency) - addressing their basic flaws - and then verify results. Details of the Input/Loss Method are well documented:

- a 20 year developmental history is available via series of articles; [6-10]
- key to all Input/Loss models and features is the accurate computation of boiler efficiency as analyzed by the EX-FOSS computer program (dating from 1985),[11] key EX-FOSS features include strict adherence to a consistent reference temperature and its ability to compute an error in efficiency given an option to input both an ultimate analysis and emission concentrations - early methods are protected by US Patent;[12]
- Input/Loss' working structure, its data flows and mechanics, are described via *www.ExergeticSystems.com*, physically Input/Loss' procedures are executed every 3 minutes while on-line, using the last 15 minutes of averaged plant data for each pass;
- besides EX-FOSS's methods, another key Input/Loss ingredient is the L_{10} Factor which allows optimization routines to correct emission concentrations; [13]
- consistent component data required for thermal performance analyses are generated, guaranteed to sum to unit heat rate as based on unique Fuel Consumption Indices (FCIs) computed via Second Law principles - FCIs are produced every 3 minutes; [14]
- allows for a variable O_2 concentration in combustion air, the φ_{Act} term in Eq.(3);
- does not include pulverizer shaft power, thus does not affect boiler efficiency; [15] and
- verification of results can be performed manually or can be automated.

Input/Loss' governing equation is the computed fuel flow (m_{AF}) of Eq.(3). Although Eq.(3) is a simple description of Input/Output, should be the governing equation for any monitoring system. Fundamentally, Eq.(3) forces understanding of the single reason we burn fuels, a developed useful energy (steam) flow (ΣQ_{WF}); it also requires the computation of boiler efficiency (η_B) independent of fuel flow (via EX-FOSS), and demands the accurate determination of calorific value and a Firing Correction (HBC) term. All of these terms are critically important if the system is to be accurately monitored leading to successful verification. Gross (HHVP) or net (LHVP) calorific values must produce identical fuel mass flows, given η_{B-HHV} and η_{B-LHV} are correctly computed.[3, 4] As an aside, it is important to note that Eq.(3) does not allow for cancellation of errors. A Powder River Basin calorific value which is erroneously <u>high</u> by 2%, will cause boiler efficiency to compute <u>high</u> by typically 0.4% using the same fuel chemistry. Fuel flow will then compute 2.4% high. Such affects are also true of the ΣQ_{WF} term; errors are not offsetting.

$$m_{AF} = \sum Q_{WF} / [\eta_{B\text{-}HHV} (HHVP + HBC)] \qquad (3A)$$
$$= \sum Q_{WF} / [\eta_{B\text{-}LHV} (LHVP + HBC)] \qquad (3B)$$

Of course, with m_{AF} and calorific value, determining unit heat rate becomes obvious. As important, note that combustion air and stack flows are computed with complete consistency since their base system stoichiometrics are based on unique fuel chemistry.

VERIFICATION PROCEDURES

Verification techniques originated by the early 2000s, this stemming from operators of Input/Loss observing that changes in emission correction factors were being identified with tube failures. These observations and much of the early development work, beginning in 1985, was support by the Mohave Generating Station, Southern California Edison, Rosemead, California, USA. Beginning in 2003 at the 640 MWe Boardman Coal Plant, Oregon, USA, an extensive testing program was begun. A portion of this testing involved emulating heat exchanger tube failures by blowing down heat exchanger headers into a flow, pressure & temperature test station. These "leakage" flows were metered, varying from 3,000 to 35,000 lbm/hr. These flows were then compared to Input/Loss' computed flows. In addition, detailed testing of measured and computed soot blowing steam flows was conducted.[15] By zeroing the metered soot blowing flow as would normally be an input to Input/Loss, its Tube Failure Model was engaged to compute a "tube leak" which satisfied system stoichiometrics. The computed "tube leak" was then compared to the metered soot blowing flow. When these quantities matched it clearly indicated that system stoichiometrics, and fuel chemistry upon which they were based, and system mass balances (both combustion gases and working fluid) were all well understood; Eq.(3) was considered resolved. In addition to matching soot blowing flow, three other verification techniques have been developed and demonstrated: matching ambient Relative Humidity, trending DCS Compensators and either matching fuel mass flow (if accurate) or trending fuel mass flow (if at least consistent).

But before further details, it is best to explain what is meant by system stoichiometrics. The following equation is a much simplified combustion equation (minor pollutants, gaseous fuels, sodium compounds for recovery boilers, and sorbent reactions are not presented for clarity). Its nomenclature is self-explanatory in that brackets are used for explanation: for example, the expression "$x\alpha_{10}$[Ash]" means the fuel moles of ash, algebraically simply $x\alpha_{10}$; the expression "$d_{Act}[CO_2]$" means the effluent moles of CO_2 found at the boundary, algebraically simply d_{Act}. The stoichiometric base of Eq.(4) is 100 moles of dry stack gas exiting the system. Note that given a resolved fuel chemistry (α_k terms), the moles of fuel/base (x) can be resolved assuming corrected effluents ($\boldsymbol{\mu}_{corr}$) based on direct effluent measurements:

$$d_{Act} = d_{Meas}\, \boldsymbol{\mu}_{corr\text{-}CO2}$$
$$G_{Act} = (g + \beta a)_{Meas}\, \boldsymbol{\mu}_{corr\text{-}O2}$$
$$J_{Act} = (j + \beta b_A)_{Meas}\, \boldsymbol{\mu}_{corr\text{-}H2O}.$$

An important quantity, which must be understood is system air leakage. Note that EX-FOSS tracks stoichiometrics on both sides of the Air Pre-Heater. Indeed, the procedures allows measurements on either side of the Air Pre-Heater ($d_{Meas}R_{Act}$, g_{Meas} and/or j_{Meas}). For example, the term "g" is the moles of O_2 on the boiler-side; all dry gases at the boiler-side sum to 100 moles. But also, the term G_{Act} is the measured O_2 found at the boundary (stack) corrected by

$\mu_{corr\text{-}O2}$, βa being the O_2 leakage term. All dry gases at the stack sum to 100 moles. The total uncorrected wet air leakage becomes: $\beta(a + a\varphi_{Act} + b_A)$.To emphasize, Table 1 contains several key terms which occur throughout Input/Loss: the combustion O_2 term (a); the ratio of non-oxygen to ambient oxygen (φ_{Act}); moisture in combustion air (b_A); and the Dilution Factor (β) & the Air Leakage Factor (R_{Act}) related to system air leakage.

$$\begin{aligned}
x[\, &\alpha_1[N_2] + \alpha_2[H_2O] + \alpha_3[O_2] + \alpha_4[C] + \alpha_5[H_2] + \alpha_6[S] + \alpha_{10}[Ash]\,]_{As\text{-}Fired\ Fuel} \\
&+ b_Z[H_2O]_{In\text{-}Leakage} + b_T[H_2O]_{Tube\text{-}Leakage} + [\,(1.0 + \beta)(a[O_2] + a\varphi_{Act}[N_2] + b_A[H_2O])\,]_{Comb\text{-}Air} \\
&= d_{Act}[CO_2] + G_{Act}[O_2] + h[N_2] + \beta a\varphi_{Act}[N_2] + J_{Act}[H_2O] + k_{Act}[SO_2] + x\alpha_{10}[ash] \qquad (4)
\end{aligned}$$

Thus system mass balances can be quickly developed from Eq.(4) as illustrated in Table 1, all based on the computed fuel chemistry and measured prime, corrected, emissions and resolved air leakage.

TABLE 1:
Mass Balances Based on System Stoichiometrics

Fuel Mass Flow, Eq.(3)	$= \sum Q_{WF}/[\eta_{B\text{-}HHV}(HHVP + HBC)] = \sum Q_{WF}/[\eta_{B\text{-}LHV}(LHVP + HBC)]$
Combustion Dry Air	$= m_{AF}(1 + \beta)(a + a\,\varphi_{Act})N_{Air}/(xN_{AF})$
Combustion Air Moisture	$= m_{AF}(1 + \beta)\,b_A\,N_{H2O}/(xN_{AF})$
Tube Leakage Flow	$= m_{AF}\,b_T\,N_{H2O}/(xN_{AF})$
Water In-Leakage Flow	$= m_{AF}\,b_Z\,N_{H2O}/(xN_{AF})$
	$\sum$ INLET MASS FLOWS
Boundary Dry Gas Mass Flow	$= m_{AF}\,100\,N_{Dry\text{-}Gas}/(R_{Act}\,xN_{AF})$
Dry Air Leakage Mass Flow	$= m_{AF}\,\beta\,(a + a\,\varphi_{Act})\,N_{Air}/(xN_{AF})$
Boundary Moisture from Air and In-Leakage, Fuel Combustion	$= m_{AF}\,J_{Act}\,N_{H2O}/(xN_{AF})$
Bottom and Fly Ash Mass Flow	$= m_{AF}\,\alpha_{10}\,N_{Ash}/N_{AF}$
	$\sum$ OUTLET MASS FLOWS

One can immediately understand, forming a system stoichiometric balance using Eq.(4), how Table 1 is formed; i.e., by first computing fuel As-Fired mass flow via Eq.(3), then with molar balances compute all air and gas mass flows. Note that total effluent O_2, the term G_{Act}, is composed of "Boiler" O_2 (without air leakage), and the air leakage contribution forming a portion of stack effluent, $a\beta$. In like manner, total effluent water, the term J_{Act}, is composed of "Boiler" moisture (without affects of air leakage), and moisture carried by air leakage, $b_A\beta$, the sum found at the stack being diluted by leakage.

It now becomes clear that matching soot blowing flow, compared to the directly measured, is an important verification technique since the computed is affected by essentially all system stoichiometric terms. A match of soot blowing flows is clearly dependent on understanding (or not) system stoichiometrics, it is also dependent on the computed As-Fired fuel flow and thus on working fluid energy flow, ΣQ_{WF}, boiler efficiency and the computed calorific value. Testing by comparing to measured soot blowing flow is a simple test, it should be run daily.

Although matching soot blowing flow is considered a universal test of First Law balances, what is also needed is a parameter which has sensitivity to system stoichiometrics, but also, from a political view-point, a parameter which can be measured outside the power plant environs; a parameter not associated with understanding system thermodynamics. This parameter is ambient relative humidity. Although it affects combustion through system stoichiometrics, it can be measured quite independently from plant instrumentation and without engineering talent. If a monitoring system ignores the measured ambient air psychrometrics, but back-calculates the air's humidity required for balancing stoichiometrics, and then successfully compares the computed to the measured, verification is assured. Of course the use of ambient humidity is not universal if given a low humidity environ.

In addition to soot blowing flow and ambient relative humidity, it appeared not unreasonable to also look to the unit's control system for verification. Controlling a power plant is a "relative" proposition. For example, in a Boiler-Follow-Turbine control mode, fuel feed is set incrementally higher or lower as affecting drum pressure such that demand power is met; absolute fuel flow, high accuracy boiler efficiency, etc. have no import. The measure of this control stems from the Boiler Master, a unit of the DCS, as its compensated output. Although there would appear no standard nomenclature, two Boiler Master parameters are considered: an Energy Compensator (in North America termed the "Btu Compensator"); also termed a "Flow Compensator". At first blush, this is a bad idea for an on-line system purporting absolute accuracy. However, there is no other direct handle on the "throttle" of the power plant than the Boiler Master. Thus the equivalent of these compensated parameters, produced by the on-line system has been investigated. Although not ideal, these computed compensators have been demonstrated as being quite reasonable for certain applications.

Further still, for verification purposes the judicious use of the plant's indicated fuel flow has come to light over three decades of Input/Loss installations - and not forgetting the intrinsic problems of measuring heterogeneous solid mass flows. As stated above, although the author traditionally believed that coal flow measurements had poor accuracy; this statement is not universally true. For a few Input/Loss installations a remarkable matching of computed versus measured fuel flows was observed over the years. Bear in mind, many Input/Loss installations have been in continuous use since the early 2000s. In response, techniques were developed to alter the fuel's water content such that the computed and measured fuel flows agreed, hour-over-hour. This said, note that verification of using fuel flow at these units was based on detailed performance testing, concluding with a proven, back-calculated fuel flow. These were specialized tests using Exergetic Systems' "Calculational Closure" techniques, requiring a minimum of 3 months for each test and analyses. In addition, when optimizing emission water (J_{Act}) both fuel flow and the L_{10} Factor are used in the optimization routines. Although in several installations forcing agreement (even with bias) seemed reasonable, such use should be approached cautiously.

VERIFICATION via SOOT BLOWING FLOW

One of several terms which affects both sides of any combustion equation is the quantity of water in-leakages into the combustion process, in Eq.(4) the b_Z and b_T terms for known flows such as soot blowing and tube leaks. Although explicitly appearing as reactants, such terms obviously effect the effluent moisture term, J_{Act}. When verifying using soot blowing flow, it is assumed the system is free of tube leaks. Input/Loss then assumes zero soot blowing ($m_Z = b_Z = 0.0$), but then employs its Tube Failure Model to solve for an unknown "tube leak". This process involves Input/Loss' optimization routines to determine m_T (via the parameter Λ_8, discussed below). Soot blowing mass flow, as a tube leak, is then computed in the following manner:

$$m_T = m_{AF}\, b_T\, N_{H2O} / (xN_{AF}) \tag{5}$$

To balance system stoichiometrics, the Λ_8 term is altered such that system stoichiometrics are balanced. This means that the entire apparatus of fuel chemistry, calorific value, system stoichiometrics, computed fuel flow, etc. are at play. Note well, the incredible sensitivity at hand: Input/loss has proven sensitivity to soot blowing flow at the ±2,000 lbm/hr level (see Figure 1) out of 4.2 million lbm/hr feedwater flow for this plant, or <0.1% error in feedwater flow. This error is fall below accuracy standards for direct feedwater water flow measurements, even using an ASME nozzle, and thus the error on in the ΣQ_{WF} term of Eq.(3).

VERIFICATION via RELATIVE HUMIDITY

The treatment of ambient moisture is not dissimilar from soot blowing flow. With system stoichiometrics in mind, the term describing moisture in ambient air, b_A, may be used to balance Eq.(4). It is important to recognize that the moles of moisture contained in combustion air appears as both a reactant term (via combustion air) and as a product term (via air leakage within J_{Act}). Moisture in combustion air affects the system's water balance, affects the hydrogen and oxygen balances about the system; and through this mechanism affects the carbon balance. For Eq.(4), the computation of b_A for ambient moisture is common:

$$b_A = (1.0 + \varphi_{Act})\, a\, \omega_{Air}\, N_{Dry\text{-}Air} / N_{H2O} \tag{6}$$

Note that specific humidity, ω_{Air}, is developed from ambient air psychrometrics, either actual or computed. The choice of comparing relative humidities, versus the specific, is arbitrary but convenient for the optimization procedures as it ranges between zero and unity (via the parameterΛ_9, discussed below) .

VERIFICATION via DCS COMPENSATORS

DCS Compensators serve to basically balance fuel flow rates against steam production as typically gaged by turbine throttle pressure. For this work what is meant by DCS Compensators, and names vary, is either a parameter which directly adjusts fuel energy flow (herein termed an "Energy Compensator"), or a parameter which adjusts fuel feed directly (herein termed a "Flow Compensator"). Such signals are generated from the Boiler Master or Turbine Master modules within the DCS.

For verification of on-line monitoring systems, the subtitles of Energy and Flow Compensators are important. All known DCS Compensator signals are Energy Compensators. For example, if at steady generation a power plant's DCS Compensator changes fuel flow from 100% to 102%, we know that the following combination of quantities has fallen by 2%: fuel heating value, boiler efficiency and/or turbine cycle efficiency. The system's Energy Compensator has reacted to maintain a constant turbine cycle load. In summary, the Energy Compensator will adjust fuel flow to maintain a desired turbine cycle energy flow, ignoring why .

If a system has absolute knowledge of calorific value and at this time was determining a valid Fuel Compensator, a change in the signal driving fuel feed from 100% to 102% would singularly indicate degradation in boiler and/or turbine cycle efficiencies of 2%, all other parameters remaining steady; the unit must fire harder to maintain generation. In summary, the Fuel Compensator will adjust fuel flow to maintain a desired turbine cycle energy flow.

Unless the DCS acquires knowledge of the fuel's calorific value, a Boiler Master's signal is only an Energy Compensator. Scaling a signal with a constant heating value, as is often done within DCS logic, and thus does not change an Energy Compensator to one of "absolute flow". An expression for the Energy Compensator is given by Eq.(7) in which "A" and "B" are scaling constants. "A" includes the affects of a constant boiler efficiency assumed for Eq.(7). HHV_{AF} is an arbitrarily chosen constant representative of the fuel burned. As used in Eq.(7), the fuel flow parameter, $m_{AF/Plant}$, is simply the plant's indication of flow, being continuously adjusted to meet demand. Meeting demand is to balance Eq.(7) which simply states that fuel energy flow (left side) is proportional to the steam energy demands of the turbine cycle (right side).

$$HHV_{AF}\, A \int m_{AF/Plant}\, dt \;[=]\; B \int \Sigma Q_{WF}\, dt \qquad (7)$$

For verification of an on-line monitoring system, all components for an absolute calculation are present. It becomes obvious that comparisons to either a Energy Compensator or to a Flow Compensator are possible. By equating Eqs.(1) and (2), an expression for fuel energy flow versus turbine cycle demand is immediately had:

$$\int \eta_B\, m_{AF}\, (HHVP + HBC)\, dt \;[=]\; B \int \Sigma Q_{WF}\, dt \qquad (8)$$

It becomes apparent that the actual signal delivered to the fuel feed mechanism is the differential, $\partial m_{AF/Plant}/\partial t$. Indeed, this signal is the output from the Boiler Master and will dictate needed changes to the plant's fuel flow if constant generation is to be maintained. Variations in this signal, if fuel energy flow is steady, counter, in the ideal, only changes in boiler and turbine cycle Δefficiencies. If heating value drops, fuel flow must increase for constant power production, the Energy Compensator will thus adjust. Although simple in concept, it is crucial for verifying any monitoring system for which the indicated fuel flow is absent, but where heating value, and boiler and turbine cycle efficiencies are being computed. For verification, even under variable load with changing HHVP and/or η_B, the computed Energy Compensator should track the DCS value with constant off-set. In summary, the Energy Compensator will adjust fuel flow based on desired turbine cycle energy flow.

There are two problems with this approach, illustrated through plant testing discussed below. First, the left side of Eq.(8) is an exact representation of steam generator performance, whereas, for verification purposes, it is being compared to an arguably crude, although consistent, control parameter (wherein HHVP & η_B, are held constant). Second, on-line systems are bound by steady state thermodynamics, and although Eq.(8) is time dependent, there are no explicit, monitored, time dependent energy terms. A transient First Law balance is simply not being made. One well-known term having considerable temporal influence is the stored energy in a steam generator's metal; another is the working fluid's stored energy contained in the deaerator and below the evaporator section in the steam generator. The author knows of no DCS Compensator which employs explicit $\partial Energy/\partial t$

storage rates; this said, energy storage affects are clearly detected by Input/Loss as seen in Figure 4. When reducing power, less fuel is actually required per MWe produced given depletion of stored energy (Input/Loss' computed fuel flow - based on steady state thermodynamics - is of course higher than the actual), and when returning to higher power, the metal's bulk average temperatures require a energy deposit (thus Input/Loss' computed fuel flow is then less than the actual).

VERIFICATION via FUEL FLOW

The result of Eq.(3), as the governing equation for on-line monitoring systems, when compared to the plant's indicated fuel flow should provide, in the ideal, ultimate verification. The first problem is that for a few coal-fired units, and certainly for bio-mass, lignite and peat units, an accurate such value rarely exists. The second problem is that for all coal-fired units indication of fuel flow can not be independently calibrated with adequate precision, unless using exhaustive testing procedures. Yes, calibration scales are employed on coal feeder belts, etc., but absolute accuracy with less than 2% error is rare; this, in spite of ill-based claims to the contrary. As thermal performance engineering typically ranges from the "0.2% to 2% level", relying on, at best, 2% absolute accuracy from a coal belt system is a fool's errand.

It is noteworthy that early development of the Input/Loss Method was carried out at natural gas-fired units in California, beginning with the company's founding in 1982. Measured gas flows were typically acquired with absolute accuracy and then compared to EX-FOSS computations. In several testing projects, we were afforded multiple flow meters in series, producing errors less than 0.3%. Indeed, if comparison with Eq.(3) was missed under such ideal conditions, then understanding coal-fired combustion was greatly optimistic. Indeed, errors in methodology were made, but over 30 years EX-FOSS development persisted producing Figure 1-type results.

However, even with these known problems with fuel flows, a technique was been developed - as a "sanity check" - in which the plant's fuel flow may be biased such that variation in the computed fuel heating value is observed, the calorific value then compared to a best estimate. At a minimum, this technique has provided the plant engineer with a visceral understanding of the inter-dependency of system stoichiometrics (effluent CO_2, etc.), fuel flow and the computed calorific value.

MECHANICS OF VERIFICATION

Again, the above techniques are <u>not dependent</u> on any specific monitoring system. If a given system can back-calculate a term which affects system stoichiometrics, which is then compared to an independent measurement, verification is possible. Having said this, one must recognize the great sensitivity a balanced set of stoichiometrics has on back-calculated b_A or b_Z terms. Data must be expected to scatter. Indeed, even for comparisons of Energy Compensators, external system factors can adversely influence. In addition to data scatter, external factors include instrumentation errors affecting stoichiometrics; e.g., errors in effluent (CEMS) data.

The Input/Loss Method assumes that no effluent instrument is free of error. To this end the Part IV paper[9] explains in detail early methods used to correct emission data. Indeed, such methods are applied to all important parameters which may affect stoichiometrics. Such parameters are termed "Choice Operating Parameters" (COPs, termed Λ_i). For Input/Loss, COPs are chosen by the power plant engineer based on the system circumstances, from any combination of those listed in Table 2.

TABLE 2:
COPs Affecting System Stoichiometrics

$\Lambda_{1S} = d_{Act}$	Stack CO_2 with air leakage affects
$\Lambda_{1B} = d_{Act}\, R_{Act}$	Boiler CO_2 without air leakage affects
$\Lambda_{2S} = J_{Act} = j + b_A\beta$	Stack H_2O with air leakage affects
$\Lambda_{2B} = j\, R_{Act}$	Boiler H_2O without air leakage affects
$\Lambda_3 = AF$	Air/Fuel ratio, for fuel ash calculations
$\Lambda_4 = R_{Act}$	Air pre-heater Leakage Factor
$\Lambda_5 = A_{Act}$	Fraction of O_2 in combustion air
$\Lambda_6 = m_{LS}$	System's indicated sorbent flow

$\Lambda_{7S} = G_{Act} = g + a\beta$ Stack O_2 with air leakage
$\Lambda_{7B} = g\, R_{Act}$ Boiler O_2 without air leakage affects
$\Lambda_8 = m_B$ <u>or</u> m_T In-leakage or tube failure mass flow
$\Lambda_9 = H_{Amb}$ Relative humidity of ambient air.

Commonly used COPs include, for example, stack CO_2, stack H_2O, air pre-heater Leakage Factor and Boiler O_2. For verification purposes COPs may include ambient relative humidity (Λ_9), or tube leakage flow which emulates soot blowing (Λ_8), or stack moisture when optimized to match m_{AF} of Eq.(3) against plant fuel flow (Λ_{2S}). The selection of one or more of the Choice Operating Parameters must depend on common understanding of power plant stoichiometrics and associated relationships to physical equipment.

However, the point here is not how one might correct any give COP - whether by historical trending, by judgment, by guess, or by using Input/Loss - but that an operational on-line system computes a relative humidity which agrees with the measured ambient ! One developed technique as used by Input/Loss employs the following procedure via ambient relative humidity as an example.

While On-Line:

Monitor the system in a routine manner using a measured ambient relative humidity of the combustion air. Calculate fuel mass flow based on Eq.(3), i.e., summarizing the monitoring system's understanding (or not) of system stoichiometrics, boiler efficiency, ΣQ_{WF} and heating value.

Periodically:

At an established frequency (say once every 30 minutes), adjust the relative humidity until the calculated fuel flow of Eq.(3) agrees with the plant's indicated value. Make certain system stoichiometrics need to be converged, to this end: a) the monitoring system might require to be taken off-line; or b) compute automatically using repetitive runs with static data to assure convergence. After fuel flows agree, then compare the adjusted relative humidity to the locally measured. If agreement of humidities is not had, place a bias on the indicated fuel flow. Repeat from above, adjusting the fuel flow bias for zero error.

Duration:

Typically, relative humidity will not greatly influence system stoichiometrics, thus data scatter associated with a back-calculated humidity must be expected. The lack of sensitivity means this procedure should be run (with the same bias on fuel flow) every day for several months.

Of course such procedures are amenable to automation. For Input/Loss, the procedure is automated such that at a pre-set number of ΔRuns, a comparison is made to ambient humidity. Typically, Input/Loss monitoring will compute relative humidity (COP of Λ_9) once every 30 minutes when optioned.

RESULTS

The viability of this work can only be demonstrated by comparisons to actual data, i.e., on-line experience. To this end, the following paragraphs present a sampling of results. However, it is suggested that verification suitable for regulatory use involving carbon taxes and the like, should involve many months of continuous application of these techniques.

Using Soot Blowing Flow

Emulating soot blowing flow using the Input/Loss Tube Failure Model has been reported.[16] This work was conducted at the Boardman Coal Plant (operated by Portland General Electric, Portland, Oregon, USA), burning Powder River Basin coal and producing 640 MWe. Results of the testing work at Boardman indicated an unexpectedly high sensitivity; as-tested sensitivity is <0.1% of feedwater flow (1,000 to 4,000 lbm/hr out of a 4.2 million lbm/hr feedwater). Figure 1 represents typical results.

Bear in mind that use of a computed soot blowing flow was originally intended to emulate tube failures, an Input/Loss feature. Although the use of this technique is applicable for monitoring verification, perhaps its greater service lies with daily checks for steam generator tube leaks. It is suggested that the plant engineer use this technique on a routine bases, say each morning for an hour, to emulate soot blowing flow. Such use will yield patterns: if soot blowing flow is consistently matched, all is well; if beginning to drift it is indication of either a tube leak or mis-monitoring. For Input/Loss, most users place great credence in time plots of computed COP correction factors; they should be drawing straight lines. Although there are automatic provisions for detecting tube leaks; as observed by users, tube leaks can well reveal themselves through changes in COP correction factors, and most importantly to Λ_1 and Λ_2.

Using Relative Humidity

Figure 2A presents one iteration of the above procedure for relative humidity; this presenting a +0.5% bias on the plant's indicated fuel flow. For this example the bias was altered four times, using -0.5, 0.0, +0.5 and +2.0% bias, each bias taking a day of monitoring. Of course, given inherent data scatter it is difficult to visually discern results. Results should be determined using a sign sensitive, square-root-sum-of-squares procedure which examines differences in specific humidities. Such results are presented in Figure 2B. For this plant (650 MWe, Nebraska City, Unit 1, operated by Omaha Public Power District, Nebraska, USA) results indicated that the plant's indicated fuel flow should be multiplied by a bias of 0.896 (plant indication is high).

Using DCS Compensators

Two examples of verification using DCS Compensators are presented, one an Energy Compensator and the other comparing Compensators, a computed Fuel versus a DCS Energy. Figure 3A compares Energy Compensators as computed by Input/Loss monitoring and a plant's DCS value. The plant was a 150 MWe peat-fired unit in the Republic of Ireland (West Offaly Power Plant). Firing peat is quite unique in that there is absolutely no indication of fuel flow. Further, it has high variability in heating value due to variable moisture content. Fuel is delivered by screw feeds, but given variation in peat density, relying on screw turns to produce mass flow is simply not credible. Given this, verification using the Energy Compensator implies that a constant off-set between the computed and the relative DCS value is proof that the system is understood. Comparison to the Input/Loss computed Energy Compensator is quite reasonable given the nature of the fuel; see Fig.3A.

Figure 3B compares an Input/Loss computed Fuel Compensator to a plant's DCS Energy Compensator. The plant is again the 640 MWe Boardman Coal Plant. As observed, the Input/Loss Fuel Compensator is more reasonably behaved than the DCS Boiler Master output (Fuel Compensator). It is believed this reflects variable fuel calorific value (opening the question of the real variability of As-Fired coal ...). But to gain verification, the Energy Compensator should be linear with the Boiler Master output, given constant load.

Using Biased Fuel Flow

To study the verification process, the Input/Loss Method was set-up to match a 660 MWe unit firing Powder River Basin coal flow rate. The fuel flow was biased by ±2%. The biased flow was matched by optimizing stack moisture (Λ_{2S}); and thus affecting fuel water content and heating value. Results are presented in Figures 4A, 4B and 4C in which the plant indicated flow is shown before bias. For the case presented, the best judgment of heating value, based on reported train samplings, was 8300 ±100 Btu/lbm as indicated on the plots. In Figure 4A, using a 0.980 bias, the computed fuel flow is seen lower than the reported before bias, while heating value (given lower fuel water) is higher than the "best estimate". Figure 4C indicates the opposite affects. Since this technique requires knowledge of the average calorific value, it is clearly not preferred. It does demonstrate sensitivities which have been appreciated for visceral understanding. However, this verification technique clearly would have merit for specialized testing involving real-time fuel samplings (if viable). Also, the technique may have merit if applied over long periods in which fuel heating value can be reasonably established.

CONCLUSIONS

This work demonstrates that verification of on-line monitoring systems is possible. Verification of coal-fired monitoring systems requires recognition that if accurate boiler efficiency is to be computed, that fuel chemistry and calorific value are required; this implies that system stoichiometrics are knowable. System stoichiometrics are fundamentally important to thermal understanding; as such, back-calculated terms based on stoichiometrics becomes key for verification. Four techniques were studied, using soot blowing flow, ambient relative humidity, DCS Compensators and fuel flow. Of these, the preferred technique involves matching a computed ambient relative humidity to a directly measured - for obvious political reasons. Back-calculated soot blowing flow is also very useful on a daily bases for either verifying the general health of the on-line system, and/or for assisting in the detection of tube leaks.

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FIGURE 1: Verification using Soot Blowing Flow, 640 Boardman Coal Plant

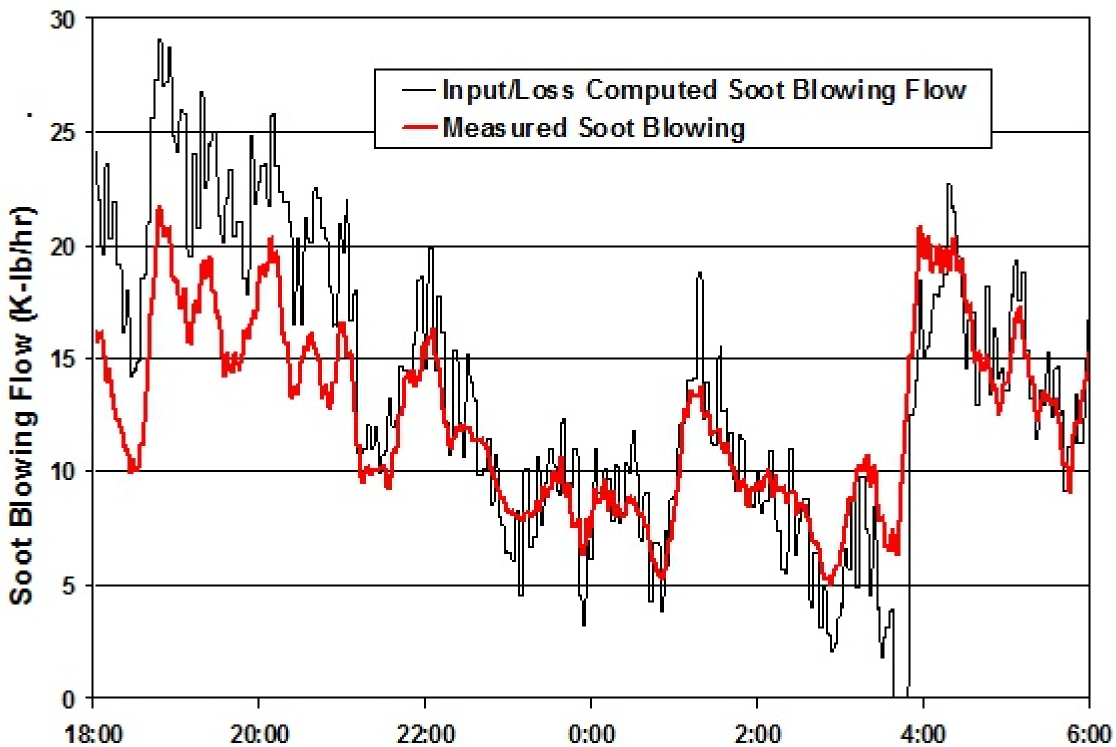
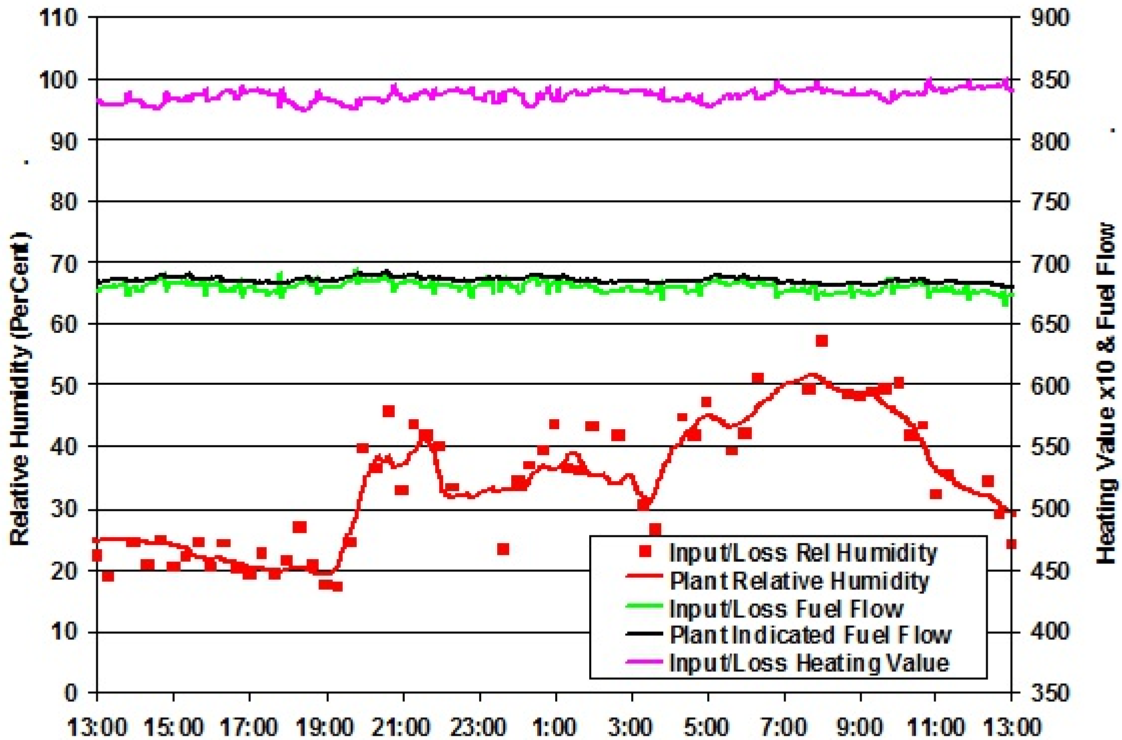


FIGURE 2A: Verification using Relative Humidity (+0.50% bias), 640 MWe Boardman Coal Plant



FIRGURE 2B: Resolution of Bias in Fuel Flow, 640 MWe Boardman Coal Plant

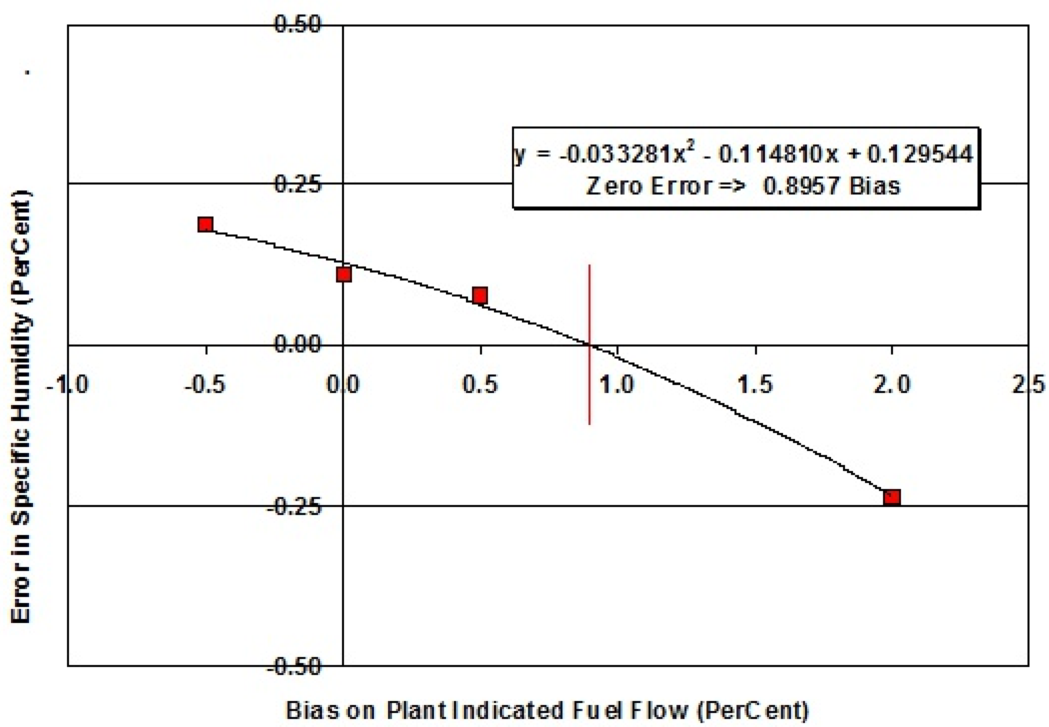


FIGURE 3A: Verification using Energy Compensator, 650 MWe Nebraska City, Unit 1

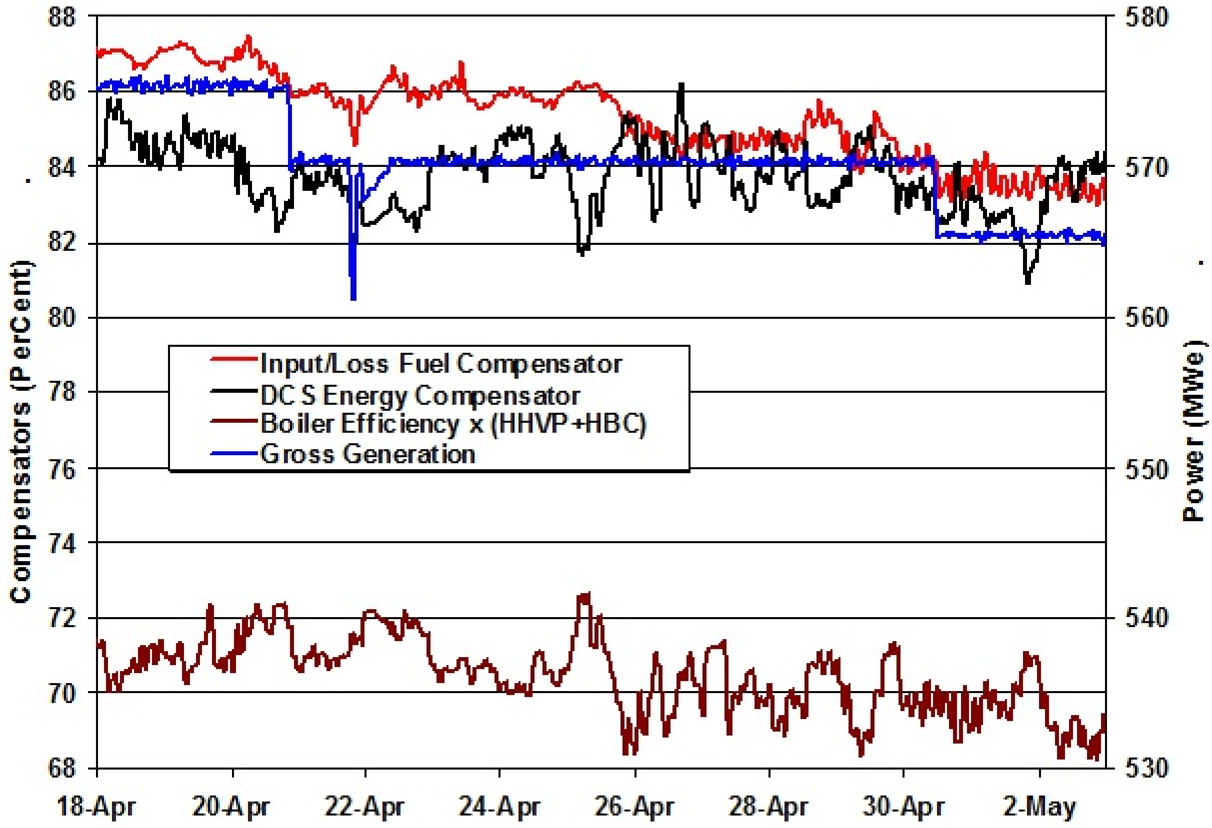


FIGURE 3B: Verification using Energy Compensator, 150 MWe West Offlay, Peat-Fired

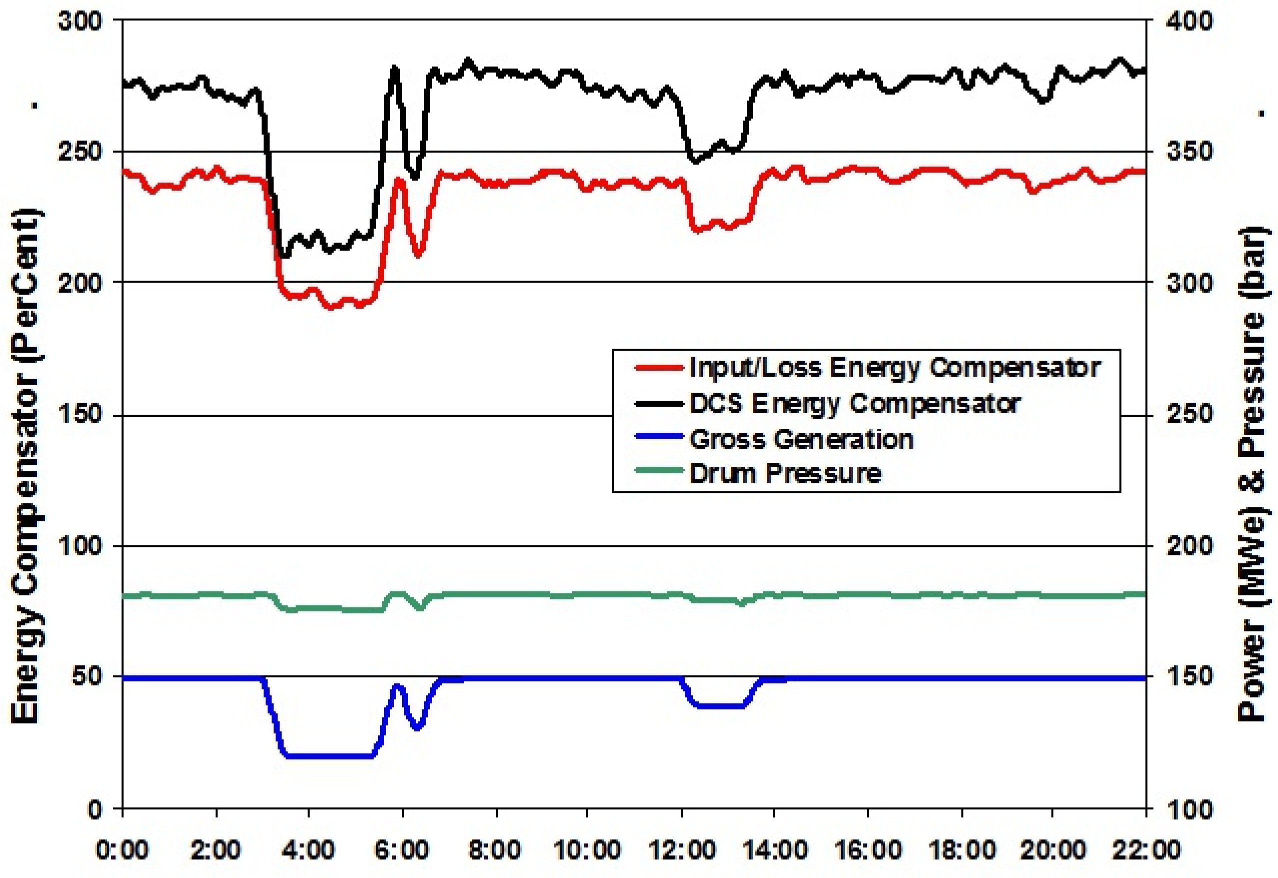


FIGURE 4A: Verification using Biased Fuel Flow (0.98 Factor)

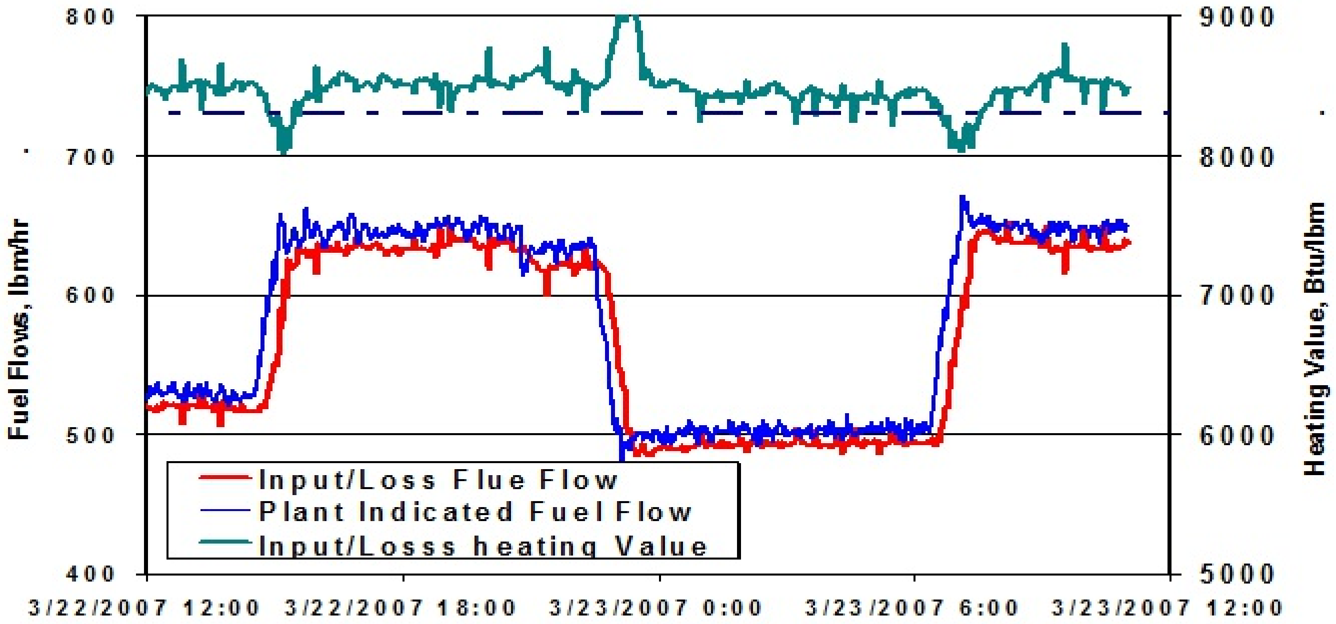


FIGURE 4B: Verification using Biased Fuel Flow (1.00 Factor)

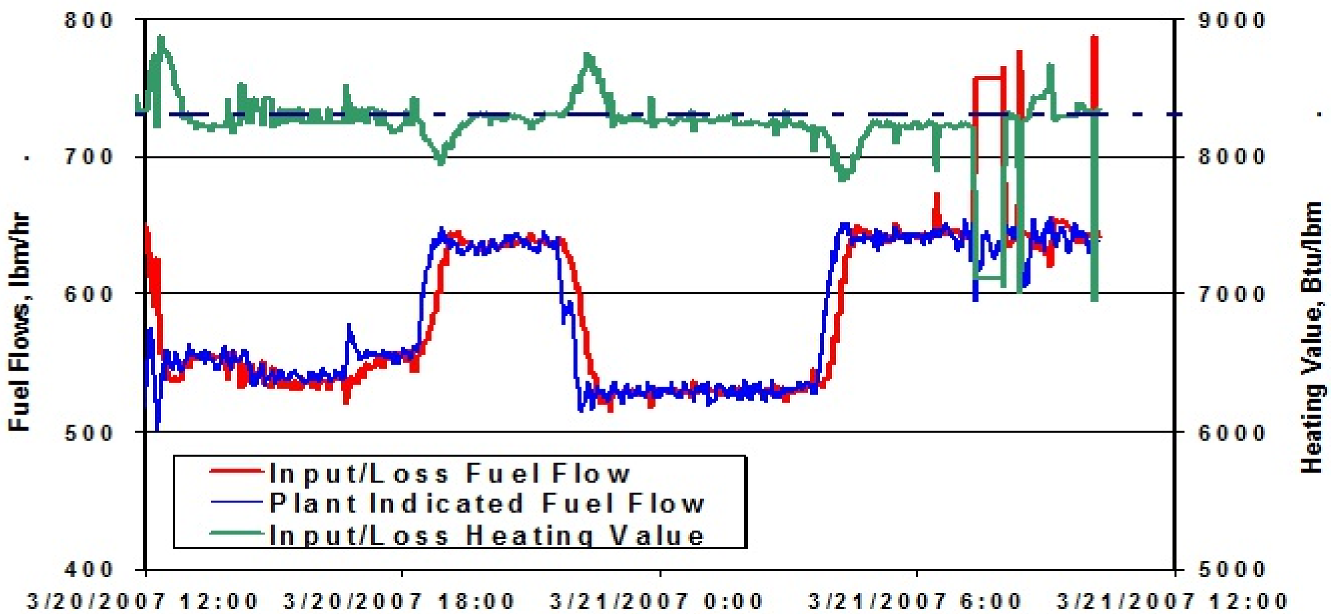


FIGURE 4C: Verification using Biased Fuel Flow (1.02 Factor)