

Comments on the English translation

of:

“Application of Adjustment Theory in Thermotechnical Tests”

a PhD dissertation submitted July 1, 1975 to the
Vienna University of Technology by Siegfried Streit

prepared by:

Fred D. Lang, P.E.
Exergetic Systems, LLC
San Rafael, California

and

Ilan Adler, PhD, Professor
Department of Industrial Engineering and Operations Research
University of California
Berkeley, California

CONTENTS:

	Page
Introduction	3
Statistical Analysis	3
Thermal Efficiency of Steam Generators	4
Dissertation Process	5
Linearity Discussion	7
State of the Thermal System	7
State of the Fossil Fuel	11
Demonstrable Technology, Research Combustor	12
Demonstrable Technology, Input Data	14
Air Leakage	14
First Category Quantities	19
Second Category Quantities	22
Executive Summary	28
Dissertation	28
European Patent 1171834 [eliminated 2023]	28
References	30
Appendix A: EX-FOSS Steam Generator Report on a 300 MWe Lignite Power Plant	32
Appendix B3-UNA: EX-FOSS Steam Generator Report on the Dissertation's Un-Adjusted Refuse Data	39
Appendix B3-ADJ: EX-FOSS Steam Generator Report on the Dissertation's Adjusted Refuse Data	44
Appendix B3-ADF: EX-FOSS Steam Generator Report on the Dissertation's Adjusted Refuse Data with Original Fuel	49

Revision History:

Rev. 0, Draft, 11 June 2009
Rev. 4, 10 Sept. 2009
Rev. 8, 11 Nov. 2009
Rev. 9, 30 Nov. 2009
Rev. 10, 01 Oct. 2011
Rev. 12, 14 Feb. 2023 (re-formatted, eliminated Patent section)

INTRODUCTION

The subject Dissertation purports to analyze all quantities comprising a computed boiler efficiency (η_B) such that, through adjustment of said quantities, a computed “tolerance” on boiler efficiency is minimized using statistical analysis. The stated purpose of the Dissertation is the minimization of the tolerance on a computed boiler efficiency, not the determination of fuel chemistry based on effluents. The boiler efficiency standard employed by the Dissertation is the German DIN 1942. ⁽¹⁾

The well-known German standard DIN-1942 is referenced as providing guiding equations and methods as to how steam generator test data is to be processed; that is, the use of uncorrected test data. The methods of DIN-1942 are not uncommon. The British had their unique standard, BS-2885. Both DIN-1942 and BS-2885 are now replaced with a uniform European standard, BS EN 12952-15 (which closely follows the last release in 1994 of DIN-1942). The American Society of Mechanical Engineers have their Performance Test Codes (PTC), PTC 4 is for Steam Generators which superseded PTC 4.1). The direct calculation of fuel chemistry and calorific value are simply not taught in these standards, they are not outputs, they are inputs to the calculations. The point here is that all steam generator standards universally teach how to calculate boiler efficiency given as supplied inputs both measurable quantities, and quantities which are assumed (best estimates). These types of quantities are herein described, respectively, as either First or Second Category Quantities. For heterogeneous solid fuels such as coal or refuse (used by the Dissertation), the uncertainty in fuel chemistry and calorific value are legendary. It is the chemistry of these solid fuels which is often assumed, or taken as best estimates based on grab examples; fuel chemistry is a Second Category Quantity. How ever obtained, fuel chemistry is an input to the computation of boiler efficiency.

Statistical Analysis

To minimize the tolerance on a computed boiler efficiency, the Dissertation employs statistical analysis whose broad procedures are well known. More specifically, let $(\mathbf{x}_1, \mathbf{x}_2, \dots, \mathbf{x}_n)$ be n vectors describing n unknown parameters, the elements of each vector \mathbf{x}_i being data samples. The “true” (and unknown) parameters may be described by $\mu_1, \mu_2, \dots, \mu_n$. Under the assumption that the measurements are distributed according to a Multivariate Normal distribution their means are then given by $\mu_1, \mu_2, \dots, \mu_n$. This system includes certain structural constraints. Consideration of structural constraints involves a number (r) of constraining functions (f_j), where $r < n$, such that:

$$f_j(\mu_1, \mu_2, \dots, \mu_n) = 0 \quad (P1)$$

where: $j = 1, 2, \dots, r$. Note that it is the relationship between different μ_i which define the constraints; e.g., $\mu_2 = 3\mu_5$. The goal then is to find maximum likelihood estimates for the parameters (as well as 95% confident intervals) subject to the structural constraints. Specifically, the goal is to calculate estimates $\bar{x}_1, \bar{x}_2, \dots, \bar{x}_n$, for the parameters $\mu_1, \mu_2, \dots, \mu_n$ together with associated tolerances $\tau_1, \tau_2, \dots, \tau_n$ such that:

- (a) The estimates $\bar{x}_1, \bar{x}_2, \dots, \bar{x}_n$ are maximum likelihood estimates of the true parameters $\mu_1, \mu_2, \dots, \mu_n$.
- (b) $f(\bar{x}_i) = 0$, where: $i = 1, 2, \dots, n$.
- (c) $Prob [(\bar{x}_i - \tau_i) \leq \mu_i \leq (\bar{x}_i + \tau_i)] = 0.95$, where: $i = 1, 2, \dots, n$. Note that this statement should be understood as meaning that “the probability is 95% that the random interval $[(\bar{x}_i - \tau_i), (\bar{x}_i + \tau_i)]$ covers the true parameter μ_i ”.

The main body of the dissertation (Chapters 2 and 3) presents the well known methodology for a general estimation problem with linear constraints. Specific application to Steam Generators is discussed in the Dissertation's Introduction, in Chapter 4, and in the Appendices where results of three applications are presented. These examples include: a combined oil- and refuse-firing (Appendix B1), an oil-firing (B2), and a pure refuse-firing (B3).

There are most serious problems with the Dissertation if the notion of using its technology is to be applied to determining fuel chemistry from combustion effluents. These problems are not only crucial to use of this technology when applied to the determination of fuel chemistry, but run to the basics of sound statistical analysis. Three principle problems include:

1. It is not clear how many measurements are to be obtained. In the three examples presented, there is no mention of data sampling. In fact, there are indications, but not clear statements, that at most one measure per parameter was taken. In addition, it is specified that a number of key measurements were not taken (with no clear discussion about how to handle the analysis and its impact on the critically important tolerance levels). This then casts doubt on the applicability of the Central Limit Theorem which is used to justify the assumption that the measurements are distributed as Multivariate Normal. As one example: the key effluent CO₂ and effluent moisture measurements are “supplied” as estimated variables which “cannot be measured directly”. Given a lack of connectedness between effluent carbon and hydrogen, and the hydrocarbon fuel, the Dissertation's methods would imply that knowledge of input fuel chemistry can be created from nothing.
2. The accuracy of the confidence intervals is crucially dependent on the variance-covariance matrix of the parameters. There is no discussion as to whether this essential data is assumed or estimated from the data. There is also no reference to this point in the presented examples. In fact, without access to, and understanding of, the source of the coefficients comprising the variance-covariance matrix, the calculated confidence intervals are practically meaningless. Table II and its associated discussion illustrates the arbitrariness of such data; which includes key data if fuel chemistry is to be determined from effluents based on Dissertation methods.
3. The proposed methodology assumes that the functions describing structural constraints of Eq.(P1) are linear. To satisfy this assumption, the functions are replaced by first order linear approximations using partial derivatives. There is no clear explanation as to how the data used for the approximations is selected, except for a vague mention that measurements are assumed to slightly deviate from the true values. But if this assumption is valid, why there is a need for elaborated methodology for the estimates in the first place? The Dissertation's linearity assumption is discussed in detail below. In the presented examples, the linearity assumptions, when combined with flawed methods, results in trivial changes in fuel chemistry; however, when analyzed for stoichiometric consistency, the changed fuel chemistry actually make stoichiometric consistency worst !

Thermal Efficiency of Steam Generators

Basic thermal efficiency is defined by all industrial standards as the useful energy flow developed (Q_{WF}), divided by the “Fuel Energy Flow” supplied (termed a Direct or Input-Output efficiency). For boiler efficiency, this basic definition is supplemented with a so-called “Heat Loss” or Indirect Method in which efficiency is defined as $(1 - \Sigma \text{Losses})$. Although there are nuances as to the definition of Fuel Energy Flow⁽²⁾, all involve the fuel's calorific value. Calorific value may be

defined as containing condensed or saturated vapor in its ideal combustion products (termed either a gross calorific value, HHV, or a net value, LHV). DIN 1942 employs an energy credit term (HBC) which accounts for fuel and air sensible heats. All standards employing the Heat Loss or Indirect Method require knowledge of the fuel's chemistry. If calorific value is to be determined *a priori*, as would be required for real-time monitoring, fuel chemistry is then required for both Methods. The following define these efficiencies in terms of Input/Loss nomenclature:

$$\text{Direct (Input-Output) Method:} \quad \eta_{\text{B-IO/net}} = Q_{\text{WF}} / [m_{\text{AF}} (\text{LHV} + \text{HBC})] \quad (\text{P2A})$$

$$\text{Indirect (Heat Loss) Method:} \quad \eta_{\text{B-HL/net}} = 1.0 - \sum \text{Losses} / (\text{LHV} + \text{HBC}) \quad (\text{P2B})$$

It is common industrial practice to employ the Indirect Method whenever possible given its improved accuracy. It is recognized that measuring fuel flow (m_{AF}) of a solid hydrocarbon, such as coal or refuse, is fraught with instrumentation error. For the Dissertation, both methods are employed, the author stating (Section 1, 16th paragraph) that:

“... since different measured quantities are used for the calculation, a calculation with the help of adjustment theory yields the same efficiencies and confidence intervals, which are also the smallest possible ones for both methods [Direct and Indirect]...”

When developing quantities for these Methods, DIN 1942 describes over 150 descriptive equations whose dependent variables may affect a boiler efficiency; each equation by contain from one or two, to a dozen, independent variables. The Dissertation's approach is to assign a tolerance to all of these independent quantities based on their “measurement error” (the specifics of such a statement are not provided). Analysis is then performed using error propagation theory such that an encompassing tolerance, assigned to boiler efficiency, is minimized. Fundamentally, minimizing the tolerance means altering quantities found in descriptive equations which comprise a computed boiler efficiency.

Dissertation Process

In establishing such a process, partial derivatives are obtained from the descriptive equations resulting in linear expressions. It is critical to the Dissertation's methods to establish linear expressions. This means that the originating descriptive equations (i.e., governing relationships) are approximated using Taylor expansion in which a specific point may be derived provided its associated independent variables are known (or assumed). For example, governing relationships involving a fractional power such as the square root of a pressure drop, or the Prandtl Number raised to the 0.6 power, or the Grashof Number raised to the 0.25 power, or the ratio of pipe diameters raised to the power of 4, or the specific volume of high temperature steam (or indeed its square root dependency regards flows through turbines), or the enthalpy of superheated steam, or the latent heat of water at constant pressure - and such a list can be continued by any practiced mechanical engineer - are all described, according to the Dissertation, as knowable at the operational condition of concern. Thus leading to linearized functions at a specified point. Without such approximation, the Dissertation's solution methodology will not function. This statement is expounded in the development which follows. This statement also includes establishing new single independent variables from multiple independent variables, which also guarantees non-linearity (exampled in the treatment of air leakage). Such combination of variables is required when addressing air leakage terms associated with commercial steam generators (air leakage is not considered by the Dissertation).

The author states there are four important requirements if the law of error propagation is to be applied for calculating tolerances based on individual measurement errors:

- 1) A linearization of functions which serve to calculate the guaranteed values from the individual measured quantities; i.e. descriptive or governing relationships.
- 2) The individual measured quantities are stochastically independent from each other. The measurement errors depend on each other.
- 3) The measurement errors are randomly and symmetrically distributed.
- 4) The number of measurements is very high.

Of these, the Dissertation author admits that no requirement is fully met. Justifications are not offered at the application level. However, submitted justifications or no, there are two fundamental difficulties with the Dissertation's theme when applied to the monitoring of a Steam Generator in real-time. The first difficulty is the linearity assumption associated with a thermal system, when operating in the real world, burning unknown fuel, and operating to meet steam load which is often dynamic. Bear in mind, the author states that linearity can be assumed since the steam generator will be tested about its guaranteed load (Dissertation, Section 1, 1st paragraph). Indeed, the author carries this statement into his work as all key parameters (water flows, fuel flows and thermal load) are all exemplified about the guaranteed point (maximum load).

The second difficulty is the lack of definition of what the words "measured quantity" (the German *messgröße*), or the words "measured value" (the German *messwert*) mean. For this discussion, these words are defined collectively as "quantities". Strict definition is required for discussion herein as it defines both "First Category Quantities" and "Second Category Quantities" when discussing fundamental concepts associated with enabling (or not) Dissertation methods. It is believed that First Category Quantities could be manipulated successfully following the Dissertation's methodology, provided the operational load is known, and sufficient sampling of First Category Quantities are obtained. However, as seen when considering Second Category Quantities (defined below), the Dissertation argues incorrectly that fuel chemistry can be manipulated through error propagation theory. Again, statements of sampling are not offered in the Dissertation. As will be seen, the Dissertation results are actually improved if its computed changes to fuel chemistry are ignored !

Regards the sampling of data, the Dissertation's assumption that the measurements are *normally* distributed is critical for the determination of meaningful confidence intervals. However, a small number of observations may lead to a distribution of the measurements that is not *normal*. The dissertation makes no mention of data sampling, indeed, there is every indication that several key values were simply assumed.

In summary, the two problems that potentially reduce the accuracy of the estimates (and particularly their confidence levels): 1) the accuracy of the variances and covariances; and 2) the lack of actual measurements associated with the input parameters. Covariances are critically needed for a realistic model in which the measurements are not stochastically independent; a stated Dissertation requirement. Again, note that discussion about how fuel chemistry data and associated tolerances were derived is simply not present in the Dissertation. It becomes clear (with evidence developed below) that use of an arbitrary fuel chemistry, with assigned - but random tolerances - produce a system whose net result on boiler efficiency can be only compensated by varying First Category Quantities (i.e., measured thermal conditions such as boiler feedwater flow, etc.).

LINEARITY DISCUSSION

The Dissertation's methodology is based on linear structural constraints, that is the functions f_j of Eq.(P1), are assumed to be linear. The Dissertation suggests using partial derivatives to obtain linear approximations based on first order terms from a Taylor expansion around the value of interest.

For this approach to work properly, knowledge of the true values (μ_j), are required (or at least their close approximations). However, these values are the very target of the suggested methodology !! For example, if data from a feedwater flow meter is to be reduced, leading to Q_{WF} of Eq.(P3) below, its measured ΔP , pressure and temperature might be approximated by a Taylor expansion provided the load point is known - but this is proposing that the answer (mass flow) is indeed known; and if so then why statistical analysis (?). However, if one is going to make slight corrections about a defined point, and to a reasonably behaved and well-known parameter (having continuous and predictable phenomena), then the Dissertation's methods might have applicability at least for First Category Quantities such as pressures, temperatures, flows, etc. But this is not the case for ill-behaved and step-wise fuel chemistry (having no predictable phenomena without using non-linear system stoichiometrics and Input/Loss Methods to supply missing equations). Solid fossil fuel chemistry is heterogeneous in nature, consisting of wild variances., having natural step-wise functionality (discussed below).

In summary, the assumption of linearity is considered most serious. The following discusses first the system, and then the nature of solid fossil fuels, both in the context of a thermal system, and a thermal system being monitored in real-time. When monitoring in real-time, there is simply no guarantee where, or how, the unit will operate: at high or low load; at steady state (base loaded) or under a load follow condition (in continual transient); and when using a fuel which is unspecified hour-over-hour. In addition to these points, the age of a power plant impacts analyses through fouling of turbine parts, the fouling of flow meters and heat exchangers, through wear to seals, increased steam trap leaks, degradation to shaft packings, and the like.

State of the Thermal System

The Dissertation does not mention the intended use of its methodology, other than to state that DIN-1942 data was to be analyzed (a standard objective of commercial Steam Generators). To demonstrate its methodology, it is applied to a small university research combustor. This combustor has no superheater, producing only saturated vapor at 32 Bar pressure. And, although it has an Air Pre-Heater, it must be of tubular design having no indicated air leakage; see Dissertation, Appendix A.1, Figure 2. Although the useful energy flow (Q_{WF}) produced from any Steam Generator affects thermal efficiency in the same manner, Eq.(2PA), computations involving a commercial Steam Generator are complex. Commercial machines universally operate at high pressure >165 bar, all employ superheaters, most have Reheat capacity, and they commonly feed steam to Regenerative Rankine cycles. For a commercial Steam Generator the computation of Q_{WF} is not trivial and decidedly non-linear through the load range.

For all modern Steam Generators integrated with Regenerative Rankine cycles, the working fluid (water) is first heated to a superheated state, and then, after expansion in a High Pressure (HP) turbine, is reheated in a Reheater heat exchanger. After HP turbine expansion, and before the Reheater, steam is extracted to "regenerate" (heat) feedwater entering the boiler. This regeneration occurs in an exchanger termed a feedwater heater. For the final feedwater heater, extraction steam may be obtained from the HP turbine's exhaust; i.e., turbine extraction steam is being extracted to a feedwater heater.

Steady state behavior of a Steam Generator supplying useful energy flow (Q_{WF}) to a

Regenerative Rankine cycle, manifests itself principally through observed variations in measured feedwater flow (m_{FW}). The useful energy flow is expressed, in its simplest form by the following (see Fig. I):

$$Q_{WF} = m_{FW}(h_{Throttle} - h_{FW}) + m_{RH}(h_{HRH} - h_{CRH}) \quad (P3)$$

where:

- Q_{WF} = Useful energy flow, kJ/hr
- m_{FW} = Feedwater flow (item **901**), kg/hr
- $h_{Throttle}$ = Enthalpy of fluid entering the HP turbine (item **901**), kJ/kg
- h_{FW} = Enthalpy of fluid entering the Steam Generator (item **903**), kJ/kg
- m_{RH} = Reheat flow (item **921**), kg/hr
- h_{HRH} = Enthalpy of fluid leaving the Reheater, Hot Reheat (item **922**), kJ/kg
- h_{CRH} = Enthalpy of fluid leaving the HP turbine, Cold Reheat (item **921**), kJ/kg.

To more fully explain, Figure I illustrates the HP side of a Regeneration Rankine cycle found throughout the world, greatly simplified. Item **903** represents the feedwater being routed to the steam generator, item **901** is superheated steam being delivered from the steam generator. Item **921** represents the so-called Cold Reheat, steam being routed to the Reheater **200** (a portion of the Steam Generator), **922** is Hot Reheat steam being returned from the Steam Generator back to the Turbine Cycle. The temperature of Hot Reheat is typically controlled by attemperation spray flow **108**. Items **905** and **907** represent a continuation of the cycle, interfaced with its low pressure side. Items **101** thru **105** are typical seal flows associated with turbine shafts and valve stems. Item **110** is the first turbine stage group of the HP turbine (Governing Stage), **120** represents the remaining HP turbine stages. Items **130** and **140** represent the Intermediate Pressure (IP) turbine. Item **430** is an open feedwater heater (Deaerator), while **420** and **410** are closed feedwater heaters; said heaters being fed turbine extraction steam **330**, **320** and **310**. Heater drains (**510** and **520**) of condensed water are routed to the next lowest pressure feedwater heater, whereas the drain of **430** is pumped forward via **711**. To compute flow to the Reheater **200**, which is required to resolve Q_{WF} for any power plant, all flows affecting the Reheater need to be resolved. These include seal flows **101**, **102** and **103**, attemperation flow **108**, and extraction flow **310**. Seals **101**, **103**, **104** and **105** are typically minor; however the cross-cylinder seal flow **102** is typically a substantial fraction of the main flow, ranging from 1% to >5% depending on the age of the turbine. Resolution of **102** can be done through direct metering or specialized testing⁽³⁾. The extraction flow **310** is resolved by mass and energy balance about heater **410**, involving thermodynamic properties of superheated steam associated with conditions at **310**. Extraction flows are classically designed to be between 4% to 7% of feedwater flow **903**, thus cannot be ignored. Therefore Reheater flow represents a 5% to possibly >10% reduction in steam generator flow **901**, and represents a substantial energy flow which is dependent on both feedwater flow, and several quantities apart from the feedwater which are quite non-linear.

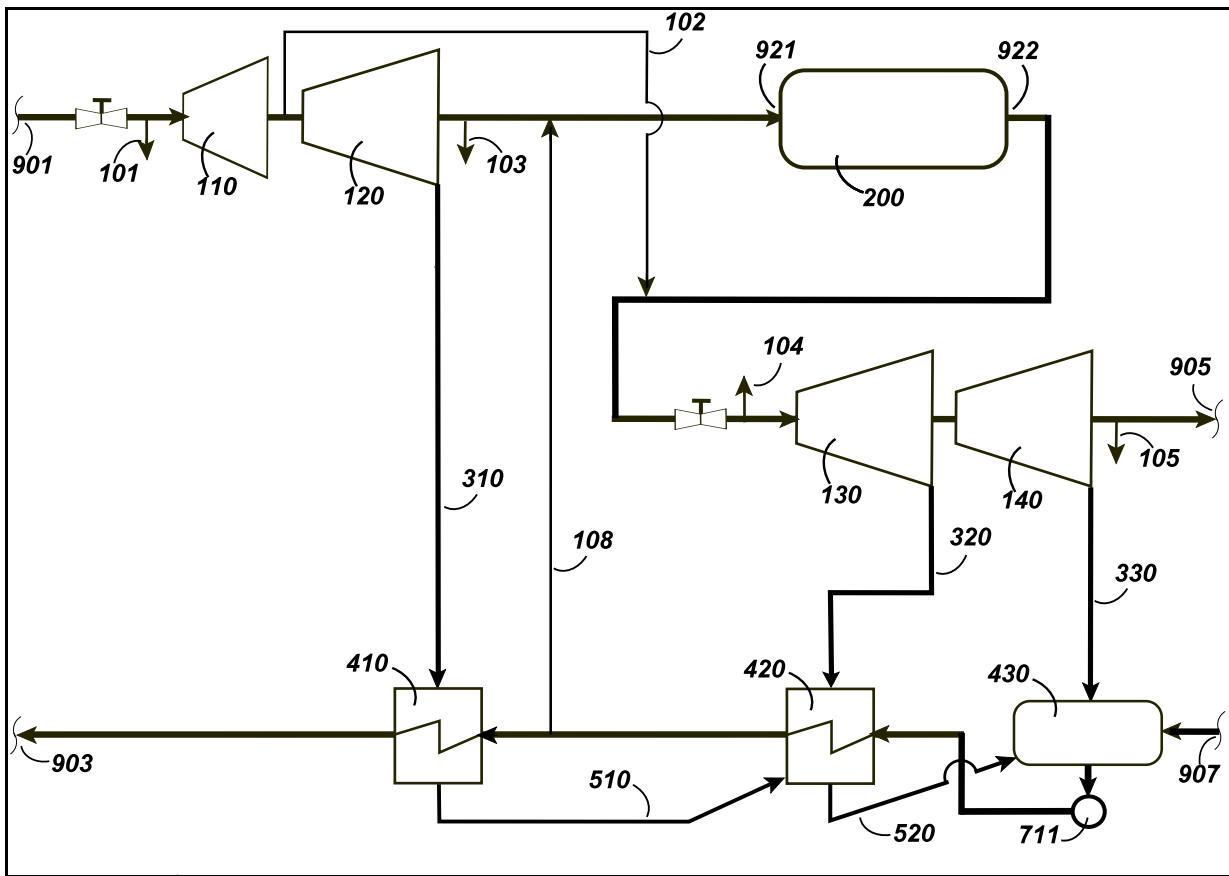
In the context of the Dissertation, if applied to a power plant, the most important parameters to the Direct Method of determining efficiency are feedwater flow (m_{FW}) and Reheat flow (m_{RH}) in the context of Eq.(P3). The metering of feedwater flow is dependent on the ΔP obtained across a flow metering device, mechanical data associated with the meter (throat diameter, pipe ID, etc.), and the specific volume of the fluid (dependent on the measured pressure and temperature local to the meter). Reduction of metering data is accomplished employing the well-known Bernoulli's equation:

$$m_{FW} = C_1 C_D Y F_a A_d (2\Delta P/v)^{0.5} / [1.0 - (d/D)^4]^{0.5} \quad (P4)$$

where:

- m_{FW} = Mass flow (feedwater), kg/hour
- C_1 = Units conversion constant
- C_D = Discharge coefficient, a ratio of actual to ideal flow
- Y = Expansion factor, for sub-cooled fluid, $Y = 1.0$
- F_a = Area factor accounting for thermal expansion, $f(T)$
- A_d = Cold area of meter at throat; m^2
- ΔP = Measured pressure drop across meter, Δbar
- v = Specific volume of fluid local to the meter, $f(P,T)$; m^3/kg
- d = Meter throat diameter, mm
- D = Inside pipe diameter, mm.

Figure I: Simplified High Pressure Side of a Regenerative Rankine Cycle



From Eq.(P4), simplifying assumptions allow its reduction to the following, Eq.(P5), as commonly used:

$$m_{FW} = C_2 (\Delta P/v)^{0.5} \tag{P5}$$

where:

- m_{FW} = Mass flow (feedwater), kg/hour
- C_2 = Combined units conversion and coefficient constants, this includes the often-times estimated actual condition of the meter (i.e., affects

due to non-linear aging, fouling & damage); actual conditions can be formerly described by the parameters C_D , (d/D) , F_a and A_d .

Note that when a flow meter is designed, it is designed using a maximum anticipated pressure drop and associated flow rate (herein termed m_{FW-max}). The Dissertation, Eq.(A.3.9), employs a correct basic equation, essentially identical to Eq.(P4), but then reduces it to one based on design (maximum) flow:

$$m_{FW} = C_3 m_{FW-max} / (v)^{0.5} \quad (P6)$$

The constant C_3 of Eq.(P6), not shown in the Dissertation, is presented here for units conversion. In Eq.(P6) the sensitivity to the measured pressure drop has been ignored, thus the sensitivity to actual conditions has been ignored. From Eq.(P6) the Dissertation proceeds - as typical of all First Category Quantities (defined below) - to obtain a first derivative based on partials.

$$dm_{FW} = (\partial m_{FW} / \partial m_{FW-max}) dm_{FW-max} + (\partial m_{FW} / \partial T) dT + (\partial m_{FW} / \partial P) dP \quad (P7)$$

The functionalities $(\partial m_{FW} / \partial T)$ and $(\partial m_{FW} / \partial P)$ are not explained in the Dissertation (postulated iterative procedures with thermodynamic properties are not explained). One can only assume that these partials are approximated by constants (differentials of linear guesses). Given these terms, a transformation matrix is formed, Eq.(A.3.13), followed by statements as to the function's stochastic independence. In essence, according to the Dissertation, the feedwater flow of a monitored power plant given its variable loading, variable fuel, variable useful output, is only dependent on the feedwater's design flow and an approximation of specific volume affects.

The derivative of the correct Eq.(P5) is as follows, clearly indicating non-linearity:

$$m_{FW} = C_2 (\Delta P / v)^{0.5} \quad (P5)$$

$$dm_{FW} = (\partial m_{FW} / \partial \Delta P) d\Delta P + (\partial m_{FW} / \partial v) dv \quad (P8A)$$

$$= C_2 (4v\Delta P)^{-0.5} d\Delta P - 0.5C_2 v^{-1.5} \Delta P^{0.5} dv \quad (P8B)$$

Another issue is the nature of the testing conducted in support of the Dissertation's methodology. The Dissertation's Figure 2 in Appendix A.1 illustrates a Steam Generator having an output steam drum, thus producing saturated steam. The Dissertation's methodology in its Appendix B, plate 10/11, lists steaming conditions (items #13, #14 & #15) by pressure, temperature and quality. In the case of burning oil and refuse (App. B1), methods result in an increase in pressure (adjustment), commensurate with a decrease in temperature. Starting as an saturated fluid, the new computed state would result in a sub-cooled liquid; this is physically impossible given an output drum boiler using, undoubtedly, moisture separators which guarantee 100% quality. In like manner Appendix B2 and B3 indicate the reverse, lower pressure with higher temperature, thus the new state would produce superheated steam; again impossible given an output drum.

In summary, problems associated with the state of a thermal system, when applying Dissertation methods, may be summarized by the following:

- The operational load of the Steam Generator must be known; the Dissertation's methodology is remarkably unsuited to monitoring power plants in real-time. Its treatment of the important feedwater flow quantity (which, for a commercial Steam Generator would be required to

compute useful energy flow, including Reheat flow), is seriously flawed. The Dissertation assumes that the flow meter's design flow, a constant associated with the guaranteed, will satisfy linearity requirements.

- The treatment of non-linear behavior at a part load is simply not taught. No attempt is made to address flow relationships in the form of Eq.(P5), involving square-root relationships with pressure drop (ΔP) and specific volume. If a Taylor expansion is to be used, its independent variables, allowing a linear computation, are simply unknowable.
- When computing a thermodynamic state point of any superheated fluid, non-linearity (i.e., non-ideal gas behavior) is the rule. This involves the state of the extraction steam (item **310**) being routed to the final feedwater heater (**410**) as needed to resolve Reheat flow.
- HP turbine seal flows routed to the IP turbine (item **102**) are quite non-linear with load and, if not metered, would require specialized testing.
- Redemptive solutions to the treatment of non-linear behaviors are simple not taught in the Dissertation; no enabling technology is offered.
- By examining the Dissertation's Appendix B output tables, it is very apparent that its methodology dose not consider non-linear behavior associated with the thermodynamic properties of steam.
- The thermodynamics as envisioned by the Dissertation are quite impossible, having no regard for physical equipment or the thermodynamic properties of water / steam.

State of the Fossil Fuel

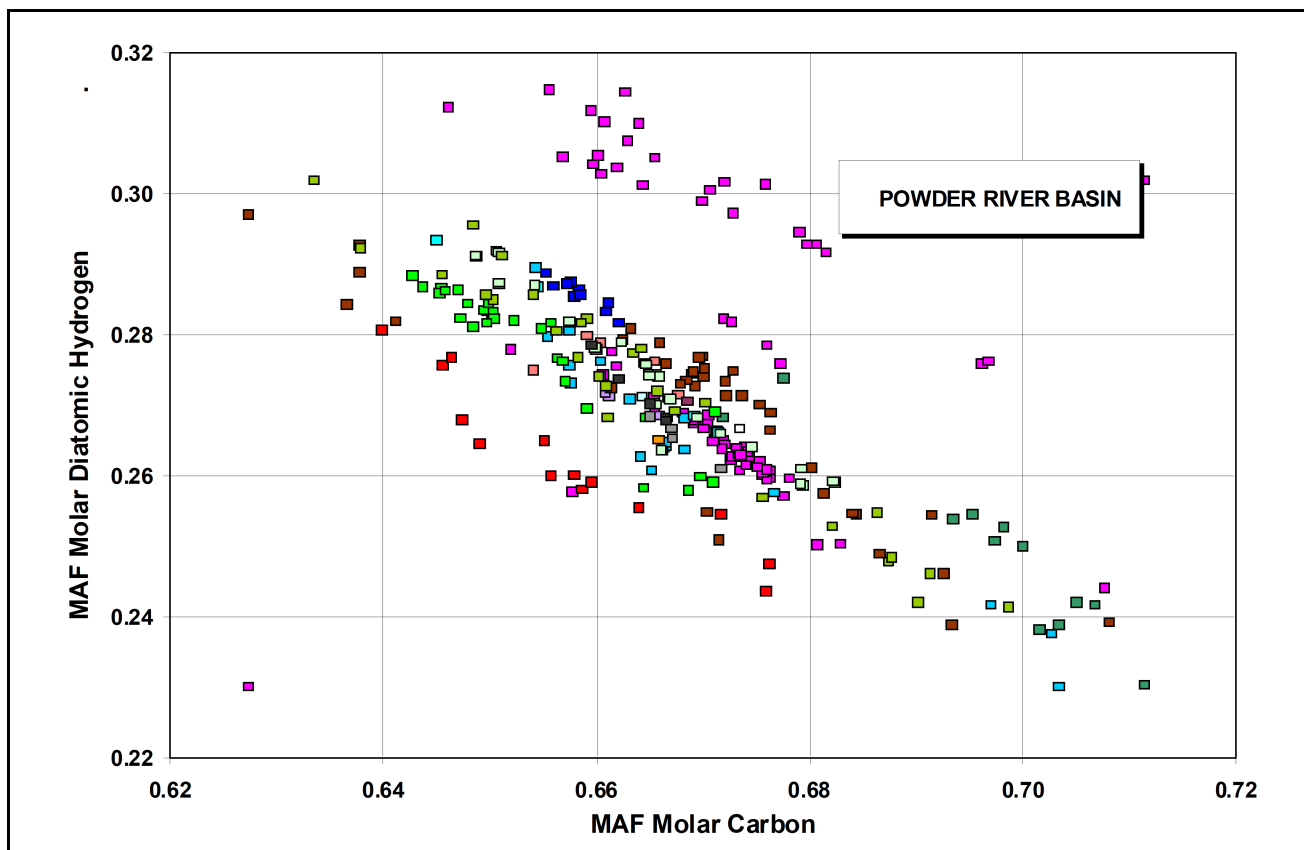
When designing Steam Generators, the vendor will be given a certain fuel chemistry from the Client, a design fuel, which, if it is to be believed at the time of bid preparation, represents the most likely fuel the as-build system will encounter. The actuality of this happening is remote at best. The vast majority of commercial steam generators operate with either variable fuel or fuel for which it was not designed. It may vary only month-over-month as with oil or gaseous fuels, as a given batch of fuel may have reasonably constant chemistry (e.g., a filled oil tank, or natural gas obtained from the same field). However, even given such likelihood, the test combustor used for the Dissertation burned oil which varied by 0.4% over an assumed short time. However, for solid hydrocarbon fuel (coal, lignite, peat and refuse), such fuels being heterogeneous, serious step-wise variations in fuel chemistry are assured; hour-over-hour changes may be regarded as the rule. In summary, two problems arise: the first is that the Dissertation assumes the as-tested fuel chemistry is near its design fuel (and near its design maximum load); and the second is the inherent variability found in solid fossil fuels. In point of fact, the Dissertation's "adjustments" to the oil and refuse fuel chemistries were quite minor; indeed, ignoring even these adjustments actually improved results.

Variability in coal is legendary, and well documented in the literature: from classical studies,⁽⁴⁾ to general literature reviews as found in the coal data libraries,⁽⁵⁾ and as would be confirmed by any experienced power plant engineer. The following a plot of moisture-ash-free (MAF) molar hydrogen verses MAF molar carbon using over 200 analyses of Powder River Basin (PRB) coals⁽⁶⁾; the data of Fig. II is color-coded according to data obtained from 14 different mines. PRB coals are by far the widest used coals in North America, but mined from just one region along the border between Montana and Wyoming. Note that the high variability associated with MAF chemistry,

given natural variability in fuel water and mineral matter (ash), then becomes atrocious when considering the As-Fuel (i.e., wet with water and ash). As is typically done, a sampling of coal will produce an “average” chemistry, but as seen in Fig. II, the intrinsic variation in solid fuels is huge; it is obvious that defining an instantaneous fuel, without descriptive system stoichiometrics and unique methods, becomes a fool’s errand.

Note that in 1998 solution was found to this problem through study of “reference fuel characteristics” leading to the Input/Loss Method.⁽⁷⁾ As invention develop, in more recent years a general solution was developed in which genetic understanding of solid fuels was discovered leading to a Third Generation Input/Loss Method⁽⁸⁾. A Fourth Generation method is being readied which, once proven, will eliminate the need for laboratory analysis. Such tools were simply not available in 1975.

Figure II: Sampling of Powder River Basin Coals (Penn State’s Coal Library)



To further illustrate the nature of coals, Figure III displays results for actual calorific value sampling conducted over a ≈ 2 hour period as part of testing a 640 MWe coal-fired unit located in the Pacific Northwest of the U.S. Note that during any 15 minute period, the calorific value often changes by 1%, at times over 4%. Such variability means, of course, the As-Fired chemistry has changed.

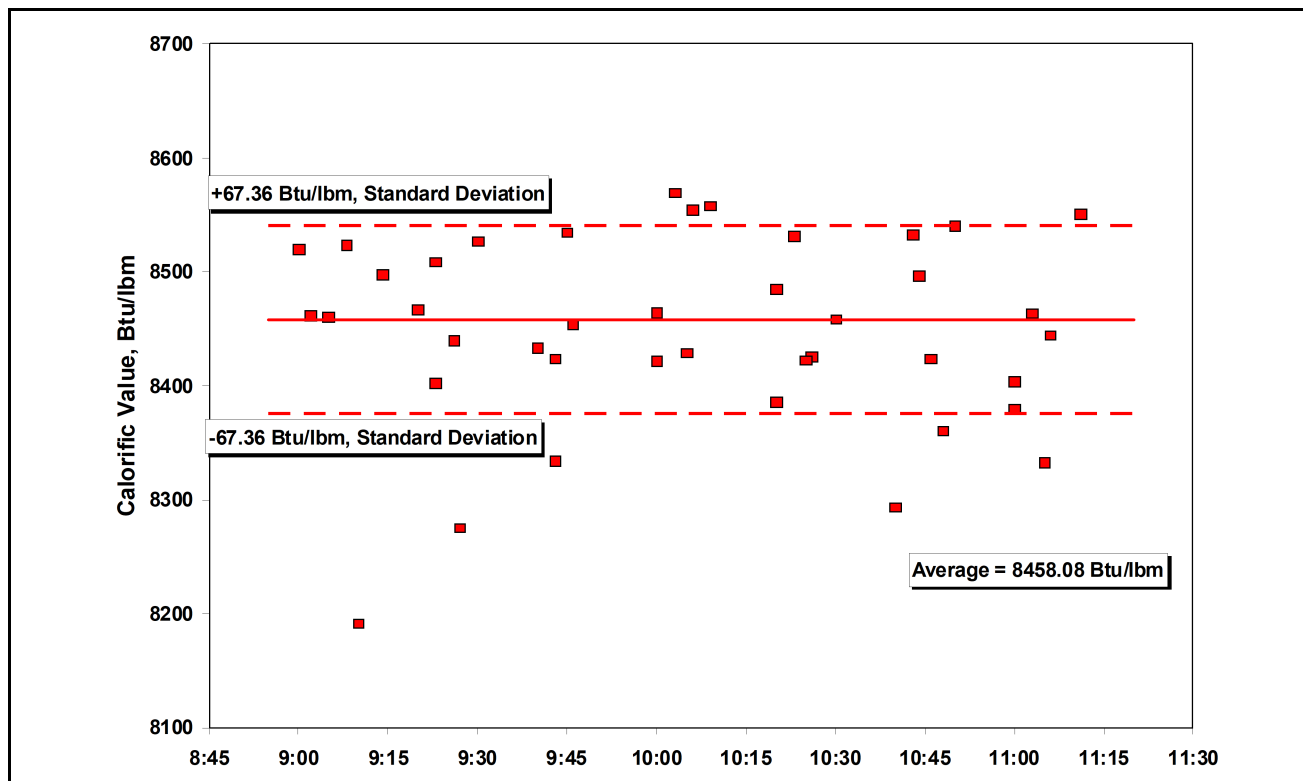
Demonstrable Technology, Research Combustor

This section examines the research combustor which was used to demonstrate the Dissertation’s methodology; refer to the Dissertation’s Figure 2 of Appendix A.1. Its output for the

three cases studied are given in Table I based on data presented in the Dissertation’s Appendix B. The Dissertation separates mineral matter (ash) from combustibles, thus refuse flow rates and CVs presented in Appendix B, plate 1 (blatt 1) and in Table I are without fly ash, slag and “scrap” [whose values were presented in plate 2].

It will be noted from Table I that the Vienna University of Technology’s research combustor is clearly of the small test variety, and obviously designed as a trash-burner. One Input/Loss installation in the Republic of Ireland, burning low quality peat, has a rated thermal load of $1,350 \times 10^6$ kJ/hr. The Steam Generator of the Irish unit supplies a 100 MWe Regenerative Rankine Cycle. As a trash burner, the Dissertation is based on a combustor which is more than an order of magnitude smaller than a small commercial power plant.

Figure III: As-Tested Calorific Values
(System Testing, October 2006, Boardman Coal Plant)



Scaling of results from a test combustor to a commercial Steam Generator is important; associated fluids are classically studied though Buckingham π theory (dimensionless numbers). Besides obvious differences in Reynolds, Prandtl and Grashof Numbers, the simplest approach is to compare thermal efficiencies as a dimensionless number. Based on Dissertation reported data, simulations were performed indicating that the boiler efficiency of Vienna University of Technology’s combustor, burning refuse, is 78.5% (output is present in this document’s Appendix B3-ADF). This efficiency is hardly comparable to a typical coal-fired net efficiency of over 90%. More specifically, an Input/Loss installation in Greece burning lignite whose calorific value is 25% less than that of the Dissertation’s As-Fired refuse, has a net boiler efficiency of 86.5%, an 8% higher $\Delta\eta_B$ efficiency (both using a net base) !! Even if methodology problems associated with non-linear behavior were resolved, enabling technology is left wanting given the lack of legitimate

demonstration. Further, given findings made concerning system stoichiometrics (discussed below), an enabling technology could only be demonstrated using a variety of solid hydrocarbon fuels; e.g., sub-bituminous, bituminous and high water fuels. When mixing refuse and oil fuels, and for the oil-firing, the Dissertation presents only trivial changes relative to the initially assumed fuel chemistries. Typically fuel chemistry changes are only made in the fourth significant digit (further discussed below, about Table III). These facts clearly indicate that enabling technology has not been demonstrated.

Demonstrable Technology, Input Data

As briefly discussed in the Introduction, Dissertation Chapters 2 & 3 present a methodology which is dependent on data sampling which allows a 95% confidence interval about the true value to be developed. However Appendix A, Section A3 clearly states the opposite, that certain parameters “cannot be measured directly”; these parameters IDs are 1, 2, 3, 4, 5, 6, 7, 8, 9 and 38. The problem here is that these certain parameters are all key if the alleged possibility of determining fuel chemistry from combustion effluents is to be realized. In Appendix B1 and B3, both dealing with refuse fuel, tolerances are assigned as obvious guesses, Table II lists these with comments; note the uniformity of assigned tolerances.

Table I: Summary of Dissertation Test Burns

Case	Unadjusted Fuel Flow (kg/hr)	Net Calorific Value (kJ/kg)	Steam Generator Thermal Load (kJ/hr)
B1: Fuel Oil & Refuse	1,274.2 (Oil) and 9,600.0 (Refuse)	40,595.0 (Oil) 10,720.0 (Refuse)	154.640 x 10 ⁶
B2: Fuel Oil	1867.8	40763	76.137 x 10 ⁶
B3: Refuse	9800	10720	105.056 x 10 ⁶

Air Leakage

Scaling issues aside, as seen in the Dissertation’s Fig. 2 the test combustor employs an air heater but without indicated air leakage; a small Tubular Air Pre-Heater would not be uncommon for such a small test machine ... if an air heater would be used at all. Air leakage is not considered in the Dissertation, it is not mentioned. It is to be noted that the thermodynamic boundary associated with DIN 1942 includes Air Pre-Heaters (which is correct).⁽²⁾

In further examining the issue of air leakage and its non-linear behavior, note that air leakage is present in all commercial Steam Generators. Such leakage is present through either corrosion or by design. The vast majority of leakages are by design, as commercial Steam Generators employ a Ljungstrom type heater which is intended to leak, having a typical design leakage of 10%. What is important here is that many times emission measurements such as O₂ will be obtained before the Air Pre-Heater (the Economizer outlet, termed the “Boiler side”); while CO₂, CO, SO₂ and H₂O (if measured) will be obtained at the Stack, downstream from the Air Pre-Heater. To employ consistent system stoichiometrics one must consider air leakage and its affects on both Boiler and Stack measurements. If consideration of Air Pre-Heater affects re ignored (as done in the Dissertation), measurements taken at the Stack must be reduced and made consistent with upstream Boiler measurements. And of course the same is true if the combustion equation includes the Air Pre-

Heater; mixed measurements must be made consistent.

The following summarizes the proper treatment of air leakage; in this light the review of its source referenced details should be considered.^(7,9) Bear in mind that a measurement of a gaseous component will be relative to the total, i.e., unity, at that location; a dry CO₂ measurement of 12% means 12 moles per every 100 moles of dry gas. Thus, if measurements are made at either the Boiler or Stack locations, and/or stoichiometrics include or exclude the Air Pre-Heater, then an ability to weigh $\sum n_i$ moles exiting the Stack (but originating from the Boiler), mixed with air leakage, will result in 100 moles at the Stack. In like manner this same consistency must be realized at the Boiler location; a dry O₂ measurement is referenced to 100 moles of dry gas at the Boiler, which is a different value when used for Stack boundary condition. Although for this discussion only dry gases are assumed (as in the Dissertation), the discussion applies equaling to wet measurements. To summarize:

$$100 \text{ moles dry gaseous effluent at Stack} = \sum n_i + \beta a (1.0 + \varphi_{\text{Act}}) \quad (\text{P9A})$$

where:

- a = Moles of true combustion O₂ input to the system (w/o leakage); moles/base.
- $\sum n_i$ = Summation of dry gases emitting from the Stack without air leakage, defined such that $R_{\text{Act}} \sum n_i = 100$ moles at the Boiler; e.g., n_{CO_2} = measured CO₂ at the Stack per 100 moles at the Stack, $R_{\text{Act}} n_{\text{CO}_2}$ = measured CO₂ at the Boiler; moles/base.
- R_{Act} = Ratio of moles of dry non-atmospheric gas from the combustion process before entering the Air Pre-Heater to the diluted non-atmospheric gas leaving, typically: (Moles of CO₂ entering the Air Pre-Heater) / (Moles of CO₂ leaving the Air Pre-Heater); defined as the Air Pre-Heater Leakage Factor; molar fraction.
- x = Moles of As-fired fuel required per stoichiometric base; for example, if the fuel chemistry is described by α_j (α_C for the moles of fuel carbon per mole fuel, α_H , α_O , etc.) then $x\alpha_j$ is the As-Fired fuel for constituent j ; moles/base.
- β = Air Pre-Heater Dilution Factor, ratio of air leakage to true combustion air; molar fraction.
- φ_{Act} = Ratio of non-oxygen gases (N₂ and Ar) to oxygen in the combustion air, common thermodynamic texts set: $\varphi_{\text{Act}} = 3.76$; molar ratio
- $\varphi_{\text{Act}} \equiv (1.0 - A_{\text{Act}}) / A_{\text{Act}}$
- $\beta a (1 + \varphi_{\text{Act}})$ = Air leakage present at the Stack; moles/base.
- A_{Act} = Concentration of O₂ in combustion air local to (and entering) the system as combustion air; the reference value for A_{Act} may be taken as 0.20948⁽¹⁰⁾.

The measurement base implies that 100 moles of dry gaseous effluent is assumed upstream of the Air Pre-Heater (Boiler), and is given by the definition: $R_{\text{Act}} \sum n_i$; thus: $\sum n_i = 100/R_{\text{Act}}$. Therefore the important Air Pre-Heater Dilution Factor may be re-defined by the following:

$$\begin{aligned} \beta &= (100 - 100/R_{\text{Act}}) / [a (1.0 + \varphi_{\text{Act}})] \\ &= 100(R_{\text{Act}} - 1.0) / [R_{\text{Act}} a (1.0 + \varphi_{\text{Act}})]. \end{aligned} \quad (\text{P10})$$

The importance of the β term is that it allows resolution of the As-Fired fuel moles, x , with (correct) dependency on air leakage. Without such a factor, any term assumed for fuel moles (based on system stoichiometrics) is simply not correct nor solvable relative to the system. Total fuel moles must have dependency on air leakage, and on what is actually measured. In summary: $[a (1.0 + \beta)]$ moles of total oxygen are delivered to the system, firing x fuel moles using a moles of oxygen; this produces

$\sum n_i$ dry effluents found at the Stack plus $(a \beta)$ moles of leakage oxygen, and $(a \beta \varphi_{Act})$ moles of leakage nitrogen. True combustion air is $[a (1.0 + \varphi_{Act})]$, leakage air found at the Stack is given by $[a \beta (1.0 + \varphi_{Act})]$.

Table II: List of Refuse Parameters Not Measured (except O₂), with Assigned Tolerances

Parameter Number per App. A3	Quantity	Sheet (Blatt) Location in App. B1 & B3	Assigned Tolerance	Comments
1	Effluent CO ₂	3	0.300	Critical for fuel chemistry.
2	Effluent CO	3	0.000	Apparently an assumed value.
10	Effluent O ₂	3	1.044	O ₂ is the only measured effluent.
12	Effluent H ₂ O	2	10.00	Wild guess.
3	Fuel carbon	1	1.000	Unknown source.
4	Fuel Hydrogen	1	0.200	Unknown source.
5	Fuel Sulfur	1	0.200	Unknown source.
6	Fuel Oxygen	1	1.000	Unknown source.
7	Fuel Nitrogen	1	0.200	Unknown source.
8	Fuel Water	1	1.000	Unknown source.
38	Fuel Chlorine	1	0.150	Unknown source.
9	Combustion Air Specific Humidity	3	1.000	An important measurement (and missing) affecting the water balance in a high-water fuel.

What is important in the context of the Dissertation, is that air leakage affects, via Eq.(P10), are clearly non-linear; they involve an $(a \beta)$ oxygen dependency. Further, if $(a \beta)$ could be approximated by a constant, then the multiple dependency of $(x \alpha_j)$ is required in which to understand fuel constituents (α_j) . The fuel moles (x) must be resolved which, again, is dependent on leakage. For specifics refer to Eq.(29) of Ref.(7). To illustrate by example, examination of Dissertation Eqs.(A.3.2) thru (A.3.5) describing effluent O₂ reveals the following constraining function:

$$\partial(O_2)/\partial(CO_2) = -1.0 \quad (P11)$$

To transcribe nomenclature to that used in this document (above), assuming effluent O₂ is measured at the Boiler and effluent CO₂ is measured at the Stack, let:

$$\begin{aligned} R_{Act} n_{CO2} &= \text{Effluent O}_2 \text{ measured at the Boiler} \\ n_{N2} + a \beta \varphi_{Act} &= \text{Effluent N}_2 \text{ found at the Stack} \\ n_{CO2} &= \text{Effluent CO}_2 \text{ measured at the Stack} \\ n_{CO} &= \text{Effluent CO measured at the Stack.} \end{aligned}$$

If effluent nitrogen is determined by difference, given it is not routinely measured, the $(n_{N_2} + a \beta \phi_{Act})$ quantity may be employed when defining 100 moles of dry gas at the Stack:

$$100 = n_{CO_2} + n_{CO} + (n_{N_2} + a \beta \phi_{Act}) + (n_{O_2} + a \beta)$$

or, for Stack oxygen: $n_{O_2} + a \beta = 100 - [n_{CO_2} + n_{CO} + (n_{N_2} + a \beta \phi_{Act})]$

for Boiler oxygen: $R_{Act} n_{O_2} = 100 R_{Act} - [n_{CO_2} + n_{CO} + (n_{N_2} + a \beta \phi_{Act}) + a \beta] R_{Act}$

Note that without leakage: $R_{Act} = 1.0$ and $\beta = 0.0$, and Eq.(P11) is valid. With air leakage Eq.(P11) becomes dependent on R_{Act} and β . Even when assuming effluent CO and ϕ_{Act} are constant, if $R_{Act} > 1.0$ and $\beta > 0.0$, the partial $\partial(O_2)/\partial(CO_2)$ becomes dependent on combustion oxygen times the leakage ($a \beta$):

$$\partial(O_2)/\partial(CO_2) = - R_{Act} - R_{Act}(1.0 + \phi_{Act}) \partial(a \beta)/\partial(n_{CO_2}) \quad (P12)$$

If, on the other hand, effluent oxygen is measured at the Stack, the following must be employed:

$$\partial(O_2)/\partial(CO_2) = - 1.0 - \phi_{Act} \partial(a \beta)/\partial(n_{CO_2}) \quad (P13)$$

Again, for both, observe the non-linear ($a \beta$) dependency. If evaluated using a Taylor expansion, the numerical quantities R_{Act} , ϕ_{Act} , a , β and n_{CO_2} are required; none of these except n_{CO_2} are assumed or measured in the Dissertation, R_{Act} and β are not mentioned.

Again, examination of the base formulation of effluent volume flow, which is critical to the Dissertation's methodology (Section A.4.6, Air Ratio), reveals similar inconsistencies. By determining the minimum volume of combustion air (theoretical combustion) based on a set of reference fuel chemistry [Eq.(A.4.5.1)], the Dissertation proceeds to develop relationships between its "air ratio" (ϵ) and the constituents of the fuel. The Dissertation's Eq.(A.4.6.7) is governing:

$$\epsilon = P_{O_2} + (W/V_{Lmin}) \{ (c/M_C) \{- 1.0 + [1 - 0.5(CO)]/[(CO_2) + (CO)]\} - n/(2M_N) \} \quad (A.4.6.7)$$

where:

- ϵ = Air ratio, moles of combustion oxygen per unit of air; kmole- O_2 / kmole-Air.
- P_{O_2} = Molar concentration of ambient oxygen, defined as 0.20950; molar fraction.
- W = Specific density of ideal gas, 22.414 m^3 /kmole.
- V_{Lmin} = Volume of theoretical combustion air given by Eq.(A.4.5.1); m^3 -Air/kg $_{MAF-Fuel}$.
- c = Mass fraction of mixed MAF fuel carbon; kg-C/kg $_{MAF-Fuel}$.
- h = Mass fraction of mixed MAF fuel hydrogen; kg-H/kg $_{MAF-Fuel}$.
- s = Mass fraction of mixed MAF fuel sulfur; kg-S/kg $_{MAF-Fuel}$.
- o = Mass fraction of mixed MAF fuel oxygen; kg-O/kg $_{MAF-Fuel}$.
- n = Mass fraction of mixed MAF fuel nitrogen; kg-N/kg $_{MAF-Fuel}$.
- cl = Mass fraction of mixed MAF fuel chlorine; kg-Cl/kg $_{MAF-Fuel}$.
- M_j = Molecular weigh of substance j; kg-j/kmole.
- (CO_2) = Effluent concentration of dry CO_2 measured at system boundary; moles- CO_2 / Total-Dry-Gas.
- (CO) = Effluent concentration of dry CO measured at system boundary; moles-CO / Total-Dry-Gas.

As discussed above the air ratio taken at the boundary must include air leakage, if present. If this

were not the case then the computed fuel and air flows (or combustion gas volume flow and air volume flows used in the Dissertation) would be obviously in error. But more to the point: since an “adjustment theory” is used, the Dissertation’s methods would be forced to assign error incorrectly, results would naturally skew. The correct form of Eq.(A.4.6.7) must be as follows:

$$\varepsilon_{\text{Total}} = P_{\text{O}_2} + (\varepsilon - P_{\text{O}_2})(1.0 + \beta) \quad (\text{P14})$$

Thus the partials of Eq.(A.4.6.8) through (A.4.6.15) leading to $\partial\varepsilon_{\text{Total}}/\partial(\text{CO}_2)$, etc. are missing the following additive terms:

$$\begin{aligned} &\partial(\varepsilon\beta) / \partial(\text{CO}_2) \\ &\partial(\varepsilon\beta) / \partial(\text{CO}) \\ &\partial(\varepsilon\beta) / \partial c \\ &\partial(\varepsilon\beta) / \partial h \\ &\partial(\varepsilon\beta) / \partial s \\ &\partial(\varepsilon\beta) / \partial o \\ &\partial(\varepsilon\beta) / \partial \text{cl} \text{ and} \\ &\partial(\varepsilon\beta) / \partial n . \end{aligned}$$

These terms are all non-linear. Although the stoichiometric bases may differ ($\text{kg}_{\text{MAF-Fuel}}$, Mole of As-Fired fuel, 100 moles of dry combustion effluent, etc.), this development is directly analogous to the $(a \beta)$ term previously discussed. One can not successfully describe a Steam Generator associated with a power plant (DIN-1942’s purpose) without considering the As-Fired fuel; As-Fired fuel can not be described without considering total air flows ... total air flow comprising system air leakage. Such concepts are simply not taught by the Dissertation, air leakage is not mentioned, there is no enabling technology.

To summarize the state of fossil fuels, and the above discussions, implies the following:

- The Dissertation assumes the As-Tested fuel chemistry is near its assumed design fuel chemistry.
- Solid fossil fuels, if to be determined based on effluent measurements must rely on an understanding of inter-relationships between the hydrocarbon’s constituents. For example, it is not credible that an incremental change in fuel carbon can be related to an incremental change in fuel hydrogen without either understanding “reference fuel characteristics”, or understanding at a deeper genetic level.
- Enabling technology was not taught by the Dissertation given the lack of demonstrable scaling based on the test machine when applied to a commercial Steam Generator. The thermal efficiency of the test machine was 8% $\Delta\eta_B$ lower than the lowest found in industry.
- The Dissertation’s work was designed to function about a guaranteed load; adjusting measurable quantities within As-Tested tolerances. Such a base approach is hardly suited to the monitoring of a coal-fired power plant whose fuel, loading and steady or un-steady behavior is unknown *a priori*.
- The Dissertation did not consider system air leakage. If so considered, partial derivatives become dependent on combustion oxygen, the solution to which is dependent on solving a combustion equation, from which requisite equations are formed dependent on $(a \beta)$ and $(x\alpha_j)$ terms; from which partial derivatives could only then be extracted.

FIRST CATEGORY QUANTITIES

Our defined “First Category” encompasses those quantities which, given their observed effects on the local environment, exhibit a measurable outcome. This can be described by the following:

Observed Effect => Induced Measurement

As examples, the following provides a visceral understanding of First Category Quantities, sometimes termed canonical measurements :

Fluid Pressure => Bar
Fluid Temperature => deg-C
Fluid Level => meters.
Combustion Gas => molar concentration (e.g., % of CO₂).

Combinations of these become obvious based on established Laws of Thermodynamics and widely available thermodynamic properties, for example:

Fluid Mass Flow => kg/hr based on a measurement: f (pressure, temperature, Δ pressure and mechanical data of the flow meter device)
Fluid Specific Volume => m³/kg based on: f (pressure and temp. or quality)
Fluid Specific Energy (Enthalpy) => kJ/kg based on: f (pressure and temp. or quality).

An important functionality, for the broader discussion herein, is the relationship between fuel chemistry and its calorific value; i.e., the chemical heat released upon combustion. Such relationships have long been studied. One of the oldest is the Dulong Formula which dates from 1822 and was based on study of the energy in foods.⁽¹¹⁾ The Dulong Formula has received much criticism starting at least since the 1890s.⁽¹²⁾ The Dissertation employs the Dulong Formula (see Section A.2, second from the last paragraph). Considerably more accurate relationships between fuel chemistry and calorific value have evolved in recent years.^(13, 14) In the context of First Category Quantities:

Fuel Chemistry => Calorific Value in kJ/kg, based on: f (explicit formula, and fuel chemistry).

Another important functionality (i.e., via descriptive equations) are the inter-relationships involving the thermodynamic properties of water (specific volume, enthalpy, etc.); the so-called “Steam Tables”. This common name is deceptive since the thermodynamic properties of water are, in general, decidedly non-linear and are not simply “table look-ups” but rather multi-dimensional surface fits. There are several very clear explanations of non-linear equations associated with the properties of water/steam.⁽¹⁵⁻¹⁷⁾ This said, there are two regions which can be approximated by linear functions: the enthalpy of sub-cooled (compressed) water at moderate pressures; and saturated vapor enthalpies having constant quality if well below the critical point (<50 Bar). By fortune, these unique regions serve as boundaries associated with the Vienna University of Technology’s research combustor (at 32 Bar and saturated output). But even given these unique properties, other important quantities remain non-linear such as transport properties, the affects on fluid quality given variable pressure, etc. The problem here is not the teachings associated with a carefully chosen research combustor, but whether the Dissertation’s methods may be applied to a modern steam generator

burning a fossil fuel. Do Dissertation methods have any universality in a non-linear world?

Table IIIA illustrates the considerable sensitivity to specific volume of saturated vapor (i.e., the influence on a steam turbine and thus Reheat flow computations), but also the insensitivity of enthalpy if quality is held constant (forcing quality variation). Table IIIB illustrates the sensitivity of specific volume of saturated liquid water to temperature, as applicable for correct metering of feedwater flow, see Eq.(P5). Table IIIC illustrates the sensitivity of enthalpy to slight variations in quality given constant pressure (in the range used by the Dissertation). Table IIID demonstrates the sensitivities of enthalpy associated with steaming conditions commonly used in the power industry. The point of these tables is to illustrate that, if carefully chosen (e.g., an assumption of constant quality, or using constant superheat temperature) reasonable linearity can be achieved. However, physical systems operating in real environments simply do not afford the convenience of such simplifying assumptions. Viable understanding of the useful energy flow produced by a Steam Generator requires the full use of unabridged and consistent thermodynamic properties of water.

It is important to note that “induced measurements” associated with First Category Quantities are dependent on explicit relationships. Such explicit relationships present first derivatives which are, commonly, strongly non-linear. In the case of using a Dulong-like formula, relationships may be correct or have considerable error which is not the case with thermodynamic properties - they are either right or wrong. The vast majority of explicit thermodynamic relationships are quite well understood, and have high accuracy if properly employed. Required First Category descriptive equations have been well established by the engineering community. These things said, nature dictates that a set of descriptive equations describing a system using water as the working fluid are non-linear. The Dissertation simply does not teach enabling technology in this area, it is an academic exercise which is not applicable.

The following summarizes findings for First Category Quantities:

- The Dissertation’s methods do not explain how the thermodynamic properties of water / steam are determined.
- Use of the Dulong Formula introduces un-necessary error.
- The issue for “induced measurements” is the identification and development of explicit relationships and their numerical evaluation. However, for commercial systems explicit relationships are typically non-linear, whose first derivatives are not constant. This situation has not been addressed by the Dissertation.
- The Dissertation methods would function for First Category Quantities provided: 1) the case studied is quite near its design (or reference) point; and 2) the unit is new thus eliminating age affects. This last requirement is critical when considering system flows in an older unit (i.e., leading to feedwater and Reheat flows).

Table IIIA: Sensitivity of Saturated Properties to Pressure

Pressure (Bar)	Sat. Vapor Sp. Volume (m ³ /kg)	Change (PerCent)	Sat. Vapor Enthalpy (kJ/kg)	Change (PerCent)
34	0.05875	0	2803.211	0
32	0.06246	6.326	2803.583	0.013
30	0.06665	11.35	2803.708	0.018
28	0.07142	21.58	2803.553	0.012

Table IIIB: Sensitivity of Specific Volume

Pressure & Temperature (Bar & °C)	Specific Volume (m ³ /kg)	Change (PerCent)
30 & 135	0.00107	0
30 & 130	0.00106	0.451
30 & 125	0.00106	0.888

Table IIIC: Sensitivity of Enthalpy to Pressure and Quality

Pressure and Quality (Bar & fraction)	Enthalpy (kJ/kg)	Change (PerCent)
30 & 1.000	2803.71	0
30 & 0.990	2785.75	0.644
30 & 0.980	2767.8	1.297

Table IIID: Sensitivity of Commonly Used Superheat Values to Pressure

Pressure & Temperature (Bar & °C)	Enthalpy (kJ/kg)	Change (PerCent)
140 & 540	3431.936	0
160 & 540	3409.426	0.66
180 & 540	3386.411	1.344

SECOND CATEGORY QUANTITIES

Our “Second Category” encompasses those quantities which have no observed effect on their environment and, commonly, no direct measurement is therefore possible. Because we burn a carbon-based fuel does not mean we can induce the fuel’s carbon content by merely measuring effluent CO₂, having no regard for the system; that is without first deduction of the system through thermodynamics (i.e., system stoichiometric, equipment usage, air leakage, etc.). Indirect outcomes must be understood through chemical-physical modeling. These are reasoned, indirect measurements which can be described by the following:

No Observed Effect => Deduced Measurement.

Of all the quantities impacting boiler efficiency, it is obvious that the only Second Category Quantity is fuel chemistry. A lab technician can measure fuel chemistry following well established procedures, however such activity does not provide real-time information. Induced, direct, measurements of fuel chemistry, in real-time, have been attempted by the power industry (using neutron activation, gamma ray spectroscopy, etc., as applied to the coal stream), but none has proven acceptable or are in wide use today. As an aside: of course the use of such an instrument would preclude Input/Loss Methods; postulating such real-time acquisition of fuel chemistry data is not germane to this discussion, and was not suggested in the Dissertation. To understand fuel chemistry based on effluents, the following defines fuel chemistry’s causality:

As-Fired Fuel Chemistry => Deduced through common descriptive system stoichiometrics, plant equipment, air leakage and based on the concentrations of measured combustion products.

The question posed is whether common descriptive system stoichiometrics based on measuring the products of combustion can provide a unique, and accurate, As-Fired fuel chemistry. The word “common”, as used herein, specifically means those methods and processes use in the Dissertation’s description (or not) of the combustion process. They are common in the sense that no “reference fuel characteristics” nor generic understanding of the fuel is offered; i.e., they do not employ Input//Loss technologies. ^(7-9, 14)

It is well established that a solid hydrocarbon fuel chemistry can not be derived from combustion effluents without applied assumptions. ⁽⁷⁾ For a common descriptive system there are simply more unknowns than equations. Applied assumptions might include any or all of the following: setting moisture-ash-free (MAF) nitrogen and oxygen constant to average values; setting fuel ash constant; and/or setting fuel water constant.

However, the mathematics associated with such a problem, if not solved properly, results in a solution which trends towards the MAF fuel chemistry initially assumed. As seen in the Dissertation’s results, this is exactly the case. Table IV presents the computed results for the principle constituents of the various test burns; changes are trivial with the exception of the refuse burn (Case B3), but changes for this case are in the wrong direction (discussed below).

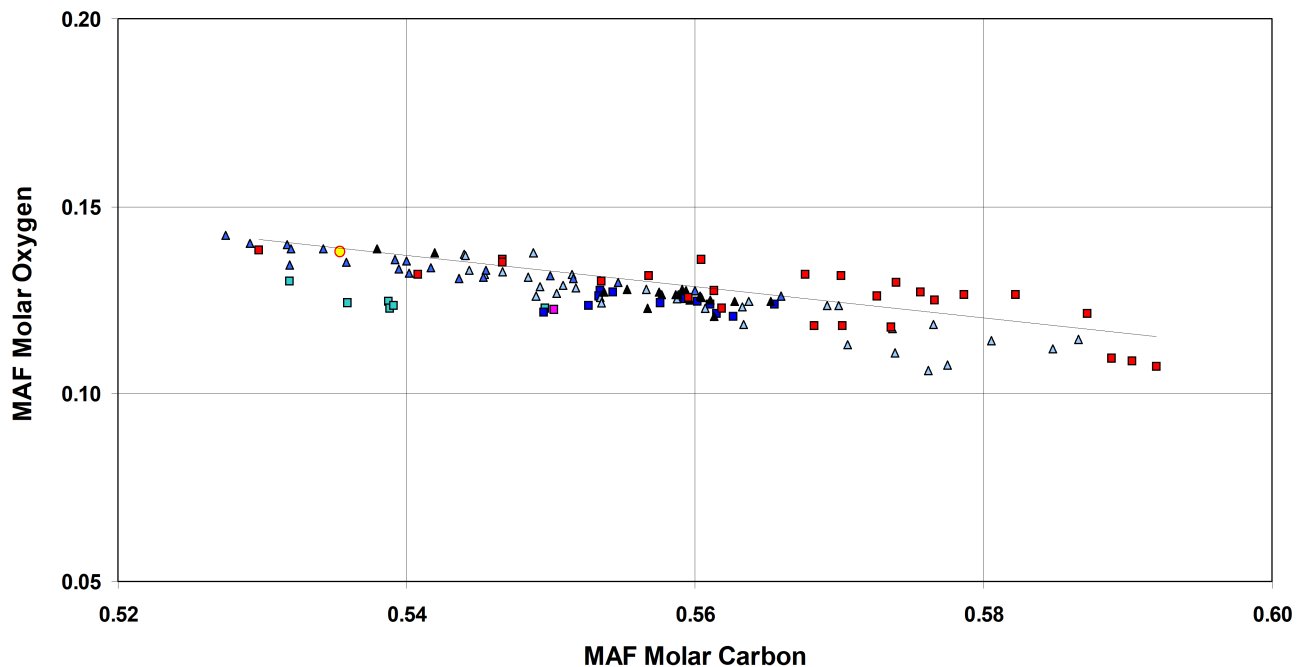
One immediate problem is that, and analogous with thermodynamic methods, Dissertation methods make no effort to comply with physical chemistry. In analyzing over 1200 ultimate analyses obtained from the Coal and Organic Petrology Laboratories of Penn. State, ⁽⁶⁾ encompassing 14 Ranks of coal, no coal, lignite nor peat exhibited a positive slope of $\partial(\text{oxygen})/\partial(\text{carbon})$ as observed

in Table IV. Further, the slopes of hydrogen and oxygen must have the same sign; see Figures IVA and IVB. Although $\partial(\text{oxygen})/\partial(\text{carbon})$ is somewhat scattered, its trend as would be predicted by an analytical model, accurate or not, must follow natural trends.

Table IV: Changes in Principle Fuel Constituents (As-Fired less Ash)

Case	Fuel Carbon & Correction	Fuel Hydrogen & Correction	Fuel Oxygen & Correction	Fuel Water & Correction
B1: Fuel Oil & Refuse	0.418697 -0.000749	0.561789 +0.000021	0.254264 -0.000388	0.241034 -0.000175
B2: Fuel Oil	0.853500 +0.000012	0.117900 -0.000007	0.00010000 +0.00000006	0.00010000 +0.00000003
B3: Refuse	0.361000 -0.006405	0.479999 +0.000842	0.288000 -0.002190	0.272999 +0.004297

Figure IVA: Irish Peat Illustrating Functionality between MAF Oxygen and MAF Carbon



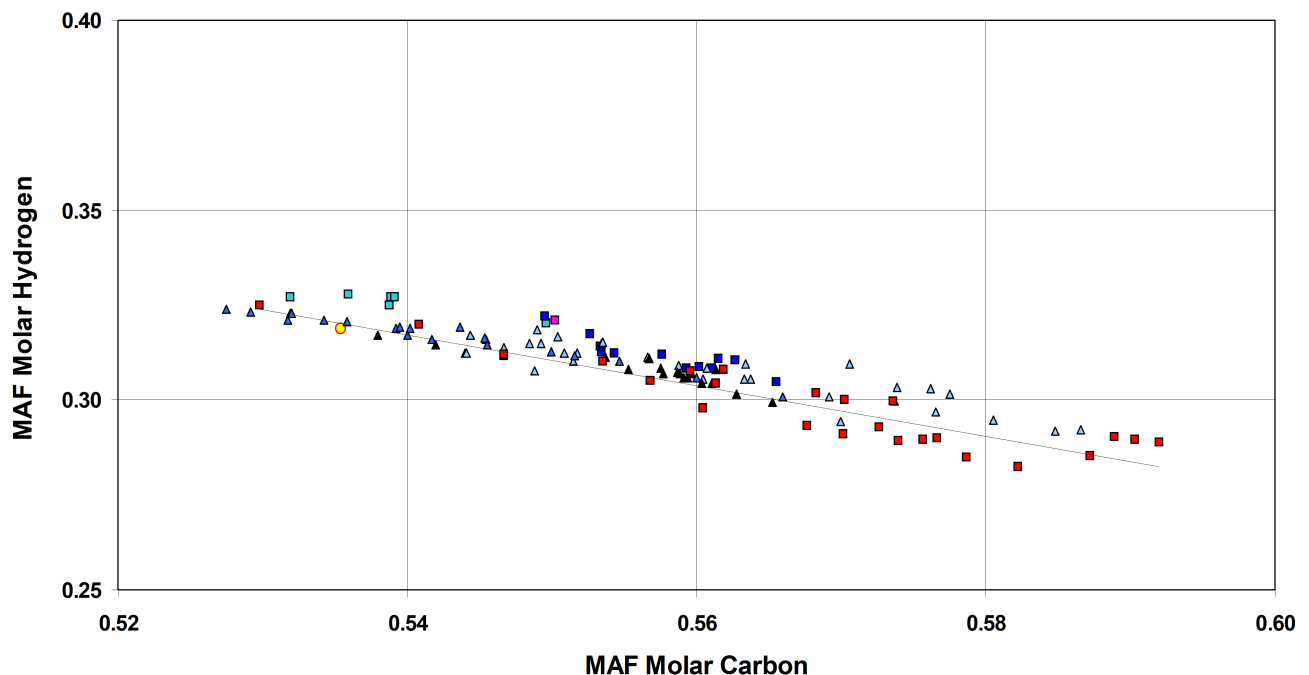
To judge whether the Dissertation’s method computes a viable fuel chemistry based on effluents, as claimed, the most simplest approach is to employ a Steam Generator simulator: input the Dissertation’s fuel chemistry (adjusted or not) and associated effluents (CO_2 , O_2 , SO_2 , etc.); and then examine resultant stoichiometric error. This is accomplished using Exergetic Systems’ EX-FOSS program which has been used to simulate fossil-fired Steam Generators for over 20 years.⁽¹⁸⁾ EX-FOSS has outstanding consistency in stoichiometric formulations. Three Control Modes have

evolved from its use over the years, they include:

- 1) a Monitoring Mode for analyzing real-time or As-Tested conditions (wherein all effluents are input including CO₂);
- 2) an Excess O₂ Mode in which effluent CO₂ is consistently computed (only O₂ and pollutants are input); and
- 3) an Excess Air Mode under which complete combustion is assumed (no effluents are input).

When in a Monitoring Mode, EX-FOSS computes an error in boiler efficiency based on stoichiometric inconsistencies which might be present in the data. In actuality the same error computation is performed as a side calculation after any given Mode has finished. What is meant by “error” is that EX-FOSS recognizes that specifying both an As-Fired fuel chemistry, and an oxygen level in ambient air, and a set of effluents (a complete set for the case of the Monitoring Mode), then the stoichiometric problem becomes over-specified. After routine computations, EX-FOSS then re-computes efficiency based on consistent stoichiometrics; the subsequent error in boiler efficiency is then reported as the difference between the actual and the consistent, a $\Delta\eta_B$. When using EX-FOSS, its long-established criteria for acceptance of test data is that the computed error in boiler efficiency be less than 0.3%. If $\Delta\eta_B > 0.3\%$ the test is repeated. For any error, $\Delta\eta_B > 0.0\%$, there exists fundamental inconsistency between fuel chemistry, effluents and/or the oxygen concentration ambient air. The latter of these can be quickly eliminated by simply decreasing the concentration of oxygen from the standard of 20.950%.

Figure IVB: Irish Peat Illustrating Functionality between MAF Hydrogen and MAF Carbon



If the methods employed by the Dissertation determines (or properly corrects) fuel chemistry, then one must see a reduction in the computed EX-FOSS error; i.e., “unadjusted inputs” versus “adjusted inputs”. Indeed, given an analytical model based on explicit physical descriptions it would

be anticipated that, for example, a change in fuel oxygen would affect effluent O₂, and thus effluent CO₂ and effluent H₂O. All fuel constituents have inter-relationships with the effluents, which is complex given consideration of system stoichiometrics including air leakage, and which is taught in European Patent (GB, GR, IT, DE) 1171834. When computing fuel chemistry based on effluents one can not simply change a measured effluent O₂, without assurance that the affects on fuel oxygen, on fuel carbon, on fuel hydrogen, etc. are stoichiometrically consistent. This then is the manifestation of Second Category Quantities, one must process such quantities with descriptions which address explicit system stoichiometrics. The Dissertation, as will be seen, simply does not.

Another important feature of EX-FOSS, as employed by Input/Loss, is that boiler efficiency is computed independent of fuel flow. Fuel flow (m_{AF}) is back-calculated from the classic definition of boiler efficiency, see Eq.(P2A). This was done since an error in efficiency will not be off-set by an error in calorific value - they compound and thus compound the error in fuel flow. Input/Loss understands the system, or not! Thus any comparison of computed fuel flow to a reasonably measured fuel flow via plant instrumentation can be a significant finding of accurate system understanding; i.e., both boiler efficiency and calorific value are understood.

A number of EX-FOSS simulations were performed for this document. The attached appendices contain four of these as described by the following; note that the lignite simulation employed the Excess O₂ Mode, all others employed the Monitoring Mode.

- Appendix A: A 300 MWe Lignite Power Plant (with a complete EX-FOSS Steam Generator Report)
- Appendix B3-UNA: Dissertation's Refuse Burn, Unadjusted Data
- Appendix B3-ADJ: Dissertation's Refuse Burn, Adjusted Data
- Appendix B3-ADF: Dissertation's Refuse Burn, Adjusted Plant Data with Original Fuel.

Note that Appendix A presents a 300 MWe Greek lignite unit whose calorific value of 6420 kJ/kg is 25% poorer when compared to the Dissertation's refuse of 8021 kJ/kg. However, the lignite plant operates with a 86.5% efficiency. Table V presents fuel flow and efficiency results for the EX-FOSS simulations.

Another deficiency, and obvious to any non-academic, is that the corrections made to the research combustor's effluent oxygen measurement are, at best, inconsistent, at worst indicate a systemic problem with Dissertation methods. A research combustor typically has a small diameter Stack, thus the measurement of effluent oxygen can not suffer greatly from flow stratification. One can assume the test burns were conducted over a reasonable time frame, thus using the same oxygen instrument. Such instruments, of course, are not sensitive to the fuel being burned(!). However, Dissertation results would indicate that its methods may be differentially applied according to the fuel and the need for certain "adjustments" - no matter their impact on the reality of instrumentation, physical equipment or physical chemistry. An instrument's bias is not a function of fuel burned, nor of analytical methods.

As seen in Table VI the Dissertation results would suggest to the casual reviewer that the same O₂ instrument has a non-predictive corrective behavior when reading an increasing 5.4% O₂ level, versus a 7.6% O₂, versus a 8.8% O₂; such correction factors running 0.780, 0.945 and 0.939. It would be inconceivable that a research combustor would not have calibrated its instrumentation, and especially for the all important effluent instruments. In 1975, as today, a common O₂ instrument would be based on ZrO₂ technology. Classically ZrO₂ technology exhibits non-linearity above 10% by volume O₂. However, such behavior was long-ago addressed by using diffusion barriers and

electronic biasing. The only possible affect might be an increase in repeatability errors as volume O₂ is increased. For an expensive instrument as would be used at a research facility, errors would

Table V: Summary of EX-FOSS Simulations

Case (I/O file)	Location (this report)	Computed Fuel Flow (kg/hr)	Computed Boiler Eff. (PerCent)	Comments
300 MWe Lignite Unit (<i>LIG-ref.INP</i>)	Appendix A	503597.7	86.493 ± 0.000	Typical Input/Loss installation, using the Excess O ₂ Mode (stoichiometric error in efficiency is independently computed).
Oil Burn, Unadjusted (<i>OIL-UNA.INP</i>)	---	1812.258	90.336 ± 3.069	Unacceptable error using original test data. The measured (unadjusted) fuel flow was 1868 kg/hr.
Oil Burn, Adjusted (<i>OIL-ADJ.INP</i>)	---	1814.174	90.381 ± 0.070	Acceptable error: major change to effluent O ₂ (5.500 to 4.214%); ≈no change to CO ₂ ; trivial fuel changes.
Oil Burn, Adjusted with Original Fuel (<i>OIL-ADF.INP</i>)	---	1814.174	90.381 ± 0.071	Acceptable error demonstrating no affect from fuel changes (only from changes in effluent O ₂). Dissertation's adjusted fuel flow was computed at 1800 kg/hr.
Refuse Burn, Unadjusted Data (<i>REF-UNA.INP</i>)	Appendix B3-UNA	13889.06	77.862 ± 1.153	Unacceptable error using original test data. The measured (unadjusted) fuel flow, with fly ash, slag & scrap terms, was 13403 kg/hr.
Refuse Burn, Adjusted Data (<i>REF-ADJ.INP</i>)	Appendix B3-ADJ	13502.79	78.782 ± 1.662	Unacceptable error: change to effluent O ₂ (8.800 to 8.264%); major change to CO ₂ (11.400 to 11.631%); changes in fuel chemistry were in the wrong direction, producing a higher error.
Refuse Burn, Adjusted Data with Original Fuel (<i>REF-ADF.INP</i>)	Appendix B3-ADF	13551.33	78.482 ± 0.017	Acceptable error: change to effluent O ₂ (8.800 to 8.264%); change to CO ₂ (11.400 to 11.631%); using original fuel chemistry. Measured fuel flow of 13403 kg/hr appears reasonable).

typically imply repeatability of 0.05% ΔO₂ from 0.20 to 10% by volume O₂, increasing to perhaps 0.5% at 25% by volume O₂. For a cheap instrument, a vendor repeatability statement of 1% ΔO₂/O₂ through the range from 0.1 to 25% volume O₂ would be expected. Dissertation data (Table VI) indicates a 22% ΔO₂/O₂ “correction” at the 5.4% level. A measurement of 5.4% O₂ was well within accurate technology for 1975. The correction factor of 0.780 applied to the signal for Case B2, with inconsistent corrections applied to Cases B1 & B3, speaks to method errors.

Table VI also reveals that consideration of explicit system stoichiometrics is wanting. If effluent O₂ is to be corrected always downward, and given no air leakage, it would be expected that the effluent CO₂ signal would either have no correction, or be corrected in a uniform manner with the

O₂ (all up or all down). As seen, the CO₂ correction for Case B2 is minor, but +1% ΔCO₂/CO₂ for Case B1, but -2% ΔCO₂/CO₂ for Case B3; both Cases B1 and B3 having similar O₂ levels (and fuel and emission flows). This makes no sense other than, again, to point to methodology errors.

Table VI: Effluent Oxygen Instrument

Case	Unadjusted Oxygen (PerCent)	Adjusted Oxygen (PerCent)	Change (PerCent)	Comments
B2: Fuel Oil	5.400	4.213	-28.17	O ₂ tolerance decreased from 1.044 to 0.365; CO ₂ was adjusted by -0.28% with small a Δtolerance.
B1: Fuel Oil & Refuse	7.599	7.179	-5.85	O ₂ tolerance decreased from 1.044 to 0.297; CO ₂ was adjusted by +0.99% with small a Δtolerance.
B3: Refuse	8.800	8.264	-6.49	O ₂ tolerance decreased from 1.044 to 0.310; CO ₂ was adjusted by -1.98% with small a Δtolerance.

The following summarizes findings for Second Category Quantities:

- The Dissertation’s methods produce either ≈no changes in fuel chemistry or changes which increase inconsistencies in system stoichiometrics. Stoichiometric errors are not explained by decreasing the ambient oxygen concentration.
- The Dissertation presents no explicit descriptions of system stoichiometrics.
- Since As-Fired fuel chemistry is a Second Category Quantity, it requires “common descriptive system stoichiometrics” which are clearly lacking in the Dissertation; there is no connectivity between fuel chemistry and combustion effluents, and their inter-relationships.
- The Dissertation might work for First Category Quantities (!!) provided the operational conditions of the Steam Generator are known; this, and provided its recommendations for changes in fuel chemistry are ignored. The Dissertation demonstrates that wholesale (and inconsistent) changes to selected parameters (effluent CO₂ and effluent O₂) produce a reduced error provided fuel chemistry is not altered.

EXECUTIVE SUMMARY

The following is an executive summary of the Dissertation, its methods and practices, and its relationship to European Patent (GB, GR, IT, DE) 1171834. More detailed summaries are presented within the body of this document following each major section..

Dissertation

- The Dissertation relies on a linear system of equations. This is justified in the Dissertation by assuming the test data is clustered about a known load point (e.g., maximum power). The consequences of non-linear affects associated with operating away from the assumed, are not discussed.
- Critically important parameters which affect the determination of fossil fuel chemistry (i.e., carbon and oxygen balances) are not measured at all; these include effluent CO₂, effluent H₂O and moisture in the combustion air. This is the situation, with a fuel whose water content is stated to be 27%. Most fuels in Europe have water contents in the 5% to 15% range (baring brown coals and lignites). In addition, the important tolerances assigned to the “assumed” fuel chemistry, as input quantities, appear to be raw guesses.
- In application of its methodology (Appendices A, B1 & B3), the Dissertation makes no statement on data sampling, nor the development of tolerance statements as assigned to critical data (much of which is not measured, but assumed). The Dissertation provides no enabling technology.
- Required system stoichiometrics including air leakage and a fuel usage term (e.g., “x” moles of fuel/base as discussed) are simply not taught.
- There are no teachings in the Dissertation which are applicable to a commercial Steam Generator whose fuel is to be monitored in real-time and whose system stoichiometrics effect the determination of fuel chemistry through metered effluents.

European Patent 1171834 ('834)

[deliberately left blank, 2023]

[deliberately left blank, 2023]

REFERENCES

- 1) “Acceptance Testing of Steam Generators”, DIN 1942: September 1956, DIN Deutsches Institut für Normung e.V., Berlin, Germany. This standard was last released in 1994, which is now superseded by European standard DIN EN 12952-15:2004; its principle methods have not changed relative to DIN 1942.
- 2) FD Lang, “Errors in Boiler Efficiency Standards”, Am. Society of Mechanical Engineers, 2009 Power Conference, POWER2009-81221. Available by permission from ASME, download from www.ExergeticSystems.com.
- 3) JA Booth and DE Kautzmann, “Estimating the leakage from HP to IP Turbine Sections”, 1984 EPRI Power Plant Performance Monitoring Conference.
- 4) DW van Krevelen, Coal: Typology, Physics, Chemistry, Constitution, Third Edition, Elsevier Science Publishers, Amsterdam: 1993.
- 5) RM Davidson, “Studying the Structural Chemistry of Coal”, Report CCC/82, IEA Clean Coal Centre, London, UK, April 2004.
- 6) Coal and Organic Petrology Laboratories, The Pennsylvania State University, University Park, Pennsylvania; see: www.energy.psu.edu/copl/doesb.html.
- 7) United States Patent 6522994 issued 18 February 2003, with Certificates of Corrections issued 17 February 2004, 13 March 2004 and 25 May 2004. Filed as a PCT application resulting in European Patent (GR, GB, DE, IT) 1171834 granted 19 January 2005. For a discussion of system stoichiometrics see the section entitled “Combustion Equation and Fuel Chemistry”. Available from www.EPO.org.
- 8) FD Lang and T Canning, “An Oxy-Hydrocarbon Model of Fossil Fuels”, Energy & Fuels, Vol. 21, No. 5, Sept/Oct 2007, Pages 2555-2565.
- 9) United States Patent 7039555 issued 2 May 2006, with a Certificate of Correction issued 8 August 2006; for an air leakage discussion, see Col. 17, Line 5 through Col. 19, Line 3. Available from www.USPTO.gov.
- 10) U.S. Standard Atmosphere 1976, National Aeronautics and Space Administration, NOAA-S/T-76-1562-NASA).
- 11) PL Dulong, “Mémoire sur la Chaleur Animale”, Annales des Chimie et des Physique (Ann. Chim. Phys.), 1841, Vol. I, pages 440-455; first read on 2 December, 1822.
- 12) B Donkin, The Heat Efficiency of Steam Boilers: Land, Marine and Locomotive, Charles Griffin & Company, London:1898. Donkin explains on page 134, that “some years ago [Dulong] was much used”; however by the early 1890s, Professor Mahler had made a large number of calorific tests comparing results with the Dulong formula proving “that the Dulong formula gave results too little by about 10 or 11%” (M Mahler, Contribution à l’Étude des Combustibles, Baudry et Cie, Paris:1893).

- 13) RC Neavel, SE Smith, EJ Hippo and RN Miller, “Interrelationships Between Coal Compositional Parameters”, Fuel, Vol. 65, pages 312-320, March 1986; a correlation formed from work conducted by the Exxon Research & Engineering Company.
- 14) FD Lang, “Monitoring and Improving Coal-Fired Power Plants Using the Input/Loss Method (Part I)”, Am. Society of Mechanical Engineers, 1998-IJPGC-Pwr-33, pp.789-797.
- 15) JH Keenan, FG Keyes, PG Hill and JG Moore, Steam Tables: Thermodynamic Properties of Water Including Vapor, Liquid and Solid Phases, John Wiley & Sons, Inc., New York, 1969; see Appendix for discussion of multi-dimensional surface fits of Helmholtz Free Energy functionality.
- 16) RC Hendricks, IC Peller and AK Baron, WASP-A Flexible FORTRAN IV Computer Code for Calculating Water and Steam Properties, NASA TN-D-7391, 1973; NASA standard based on Ref.(15).
- 17) L Haar, JS Gallagher and GS Kell, NBS/NRC Steam Tables: Thermodynamics and Transport Properties and Computer Programs for Vapor and Liquid States of Water in SI Units, Hemisphere Publishing, New York, 1984; see Appendix A: The Helmholtz Function for discussion of multi-dimensional surface fits.
- 18) FD Lang, EX-FOSS: A Program for Monitoring & Analysis of Fossil-Fired Boilers, Exergetic Systems, Inc., San Rafael, CA., August 2009, Ver.2.8, Mod.18, first published 1983.

APPENDIX A:

**Steam Generator Report on a
300 MWe Lignite Power Plant
(EX-FOSS Simulation)**

S T E A M G E N E R A T O R P E R F O R M A N C E R E P O R T

Reference of Lignite Fuel, 300 MWe.

Off-Line using LHV

Contents	Page
Title, Approvals & Input	1A&B
Mass/Energy Balances	2A
Stoichiometrics	2B
Turbine Cycle Data	3A&B
Heat Transfer Data	4A
Miscellaneous Data	4B
Summary of Boiler Losses	5A
Summary of Air Components	5B
Second Law Analyses	6A&B
Input File: LIG-ref.INP	
Output File: LIG-ref.INP	
Report File: LIG-ref.ESI	

Analysis produced by: EX-FOSS, Ver.2.8/Mod.18
(c) 2009 by Exergetic Systems 415-455-0100
12 San Marino Dr., San Rafael Calif. 94901
Responsible Engineer:
Date: _____
Supervising Engineer:
Date: _____
Time and Date of Analysis: 14:18 on 09/09/08

LHV EFFICIENCIES & VAR. --
Combustion: .88292 +/- .00000
Absorption: .97962 +/- .00000
Boiler: .86493 +/- .00000

HEAT TRANSFER RESULTS/RECOMMENDATIONS --
IDFan SHT-I Test #1
STM Soot
AIR RHT-II Test #1
 Test SH-III Test #1
Econ Test #1 SH-II Test #1
RHT-I Test #1 Boiler Test #1

I N P U T D A T A

F2 INPUT --
Fuel: Coal (1)
Ctrl: Input Stack Excess O2 in F3 (3)
Excess Air, Ctrl = 4 (Fract): .163465
Higher Heating Value (kJ/kg): 7837.455
Lower Heating Value *(kJ/kg): 6420.340
Dry Bulb Temperature (deg-C): 14.9455
Wet Bulb / Rel. Humd. (C/Frac): .568978
Ref O2 Fract. in Air (Fract): .209480
Fuel Specific Gravity(Fract): 1.00004
Fuel Pressure (k-Pa): 101.324
Fuel Temperature (deg-C): 14.9455
Atmospheric Pressure (k-Pa): 101.325
Ref Fuel Calorimetric(deg-C): 35.0000

F3 INPUT --
Flue Gas Pressure (k-Pa): 101.325
Flue Gas Temperature (deg-C): 158.584
Actual Adiabatic Temp(deg-C): 1325.86
Targeted O2/-CO Trim (Fract): .030000
Ratio of SO3/SO2 (Fract): .050000
Ratio of NO/NOx (Fract): 1.00000
Ratio ESP SO2 Out/In (Fract): 1.00000
Ratio APH Gas In/Out (Fract): 1.16057

F4 INPUT --
Heat Transfer Mode: Test Input (3)
Cleanliness Cutoff: 0.85
Applicable Eq: 2 Calc.Option/Test No: 1

F7 INPUT --
Calc or Ref Fuel Flow (kg/hr): 503597.7
Loss from Rad. & Conv.(Fract): .0050000
Bottom Ash/Fuel Flow (Fract): -.120000
Carbon/Bottom Ash (Fract): .0261000
Fly Ash/Fuel Flow (Fract): -.050000
Carbon/Fly Ash Ratio (Fract): .0057000
Sp. Heat of Refuse (kJ/kgK): 1.256038
Dry Bottom Ash Temp. (deg-C): 525.0000
Rejects/Fuel Flow (Fract):
Rejects Uncorr. LHV (kJ/kg):
Dust/Fuel Flow Ratio (Fract): .0812721
Sp. Heat of Fly Ash (kJ/kgK): 1.214170
Gross Unit Ele. Power (kWe): 302000.0
Summation Pump Power (kWe): 12000.00
Circ. or Makeup Flow (kg/hr): 48988800
Circ. Water Temp. (deg-C): 30.00000
Tower Moist Air Flow (m^3/h):
Boiler Power Input Bx (kJ/hr):

Appendix A: Typical Lignite Steam Generator

Page 2A of 6B

M A S S / E N E R G Y B A L A N C E S

LHV ENERGY BALANCE (kJ per kg As-Fired) --

Corrected Lower Heating Value LHVP	6334.579
Heat in As-Fired Fuel Flow	+ -50.5872
Heat in Dry Air & Moisture	+ -69.5119
Water/Steam Leakage (F5/6)	+ .0000000
Heat in LS, Stm-Air, FDFans	+ .0000000
Boiler Firing Corrections, HBC	+ -120.099
-> TOTAL FUEL AND SYSTEM INPUT	= 6214.480
Energy in Combustion Products (w/Stack Losses), HPR	8095.324
Energy in As-Fired Reactants (Fuel, Air & LS), HRX	- 2608.409
Total Energy Released During Combustion, ERC/WWFUEL	= 5486.915
Gross Boiler Non-Chemical & Sensible Heat Losses, HNSL	- 111.8039
Total Heat Delivered to Working Fluid, BBTCYC/WWFUEL	= 5375.111
Gross Boiler Stack and Sensible Heat Losses, HSL + HNSL	+ 839.3681
-> TOTAL GROSS STEAM GENERATOR ENERGY OUTPUT	= 6214.480

MASS FLOW BALANCE (kg/hr) --	Boiler Dry Gas Flow	1574651.
Calc. As-Fired Fuel Flow, WWFUEL	Boiler Moisture	+ 322420.5
Pulverizer Rejected Fuel Flow	Wet Air Heater Leakage	+ 237643.7
Inlet Combustion Dry Air Flow	Pulverizer Rejected Fuel	+ .0000000
Inlet Combustion Air Moisture	Limestone Products	+ .0000000
In-Leakage of Water & Steam Flow	Carbon in Bott & Fly Ash	+ 2005.637
Inlet or calc Limestone (CaCO3)	Ash with SO2 Capture (F2)	+ 99782.91
-> TOTAL INLET FLOW TO BOILER	= 2236504.	-> TOTAL OUTLET FLOW = 2236504.

Page 2B of 6B

S T O I C H I O M E T R I C S DRY GASEOUS

		AIR PH INLET	OUTLET
AS-FIRED FUEL (weight fractions, unadjusted input)	PRODUCTS (%)		
Nitrogen	Carbon Dioxide +	16.81623	14.48965
Water	Comb. Oxygen +	2.973467	2.562078
Oxygen	Comb. Nitrogen +	80.05944	68.98298
Carbon	Comb. Moisture	35.09451	30.23908
Hydrogen	Sulfur Dioxide +	.1433183	.1234898
Sulfur	SO2 Ash Capture	.0000000	.0000000
Carbon Dioxide	Carbon in Ash	.3274391	.2821369
Carbon Monoxide	Ash (from F2)	2.795217	2.408491
Chlorine	Sulfur Trioxide +	.0075431	.0064995
Ash (F2 input)	Carbon Monoxide +	.0000000	.0000000
ID =	NOx (combined) +	.0000000	.0000000
ID =	Free Hydrogen +	.0000000	.0000000
ID =	ID = +	.0000000	.0000000
ID =	ID = +	.0000000	.0000000
ID =	Leakage Oxygen +		2.898219
ID =	Leakage Nitrogen +		10.93708
ID =	Leakage Moisture		.1332781
ID =	-> TOTAL MOLES DRY GAS (+)	100.0000	100.0000
ID =	As-Fired Fuel/100 Mole Dry Gas Base, x	= 49.24825	
ID =	Inlet Oxygen at Boundary, a*(1 + beta)	= 21.13392	
ID =	Inlet Air Moisture [F2], bA*(1 + beta)	= .9718688	
ID =	In-Leakage of Water & Steam [F5/6], bZ	= .0000000	
-> TOTAL FUEL WT = 1.0000000	Inlet Pure Limestone, bPLS*(1 + gamma)	= .0000000	

Appendix A: Typical Lignite Steam Generator

T U R B I N E C Y C L E D A T A (F5 SCREEN)

ID of Interface	Monitoring or Test Data	Heat Exchanger	Energy Transferred
Heat EXCHG (Type)	Flags T-G S-G I/O	for Gas, Air & Working Fl	from Gas to Work.Fl.
	Flow Press Temp Enth	Temp LMTD U	kJ/hr kJ/hr
	kg/hr k-Pa deg-C kJ/kg	deg-C del-C kJ/hm2	
IDFan	N Out: 2134716. In: 2134716.	158.6 156.1	158.6 156.1
STM	N In: 1732906. Out: 1732906.	101.32 101.22	30.79 30.79
AIR	N In: 1732906. Out: 1495263.	101.22 100.52	30.79 280.0
Econ	Y In: 841443.5 Out: 841443.5	22307. 21861.	259.5 349.0
RHT-I	Y In: 921639.2 Out: 921639.2	4016.3 3895.8	355.0 425.8

T U R B I N E C Y C L E D A T A (F6 SCREEN)

ID of Interface	Monitoring or Test Data	Heat Exchanger	Energy Transferred
Heat EXCHG (Type)	Flags T-G S-G I/O	for Gas, Air & Working Fl	from Gas to Work.Fl.
	Flow Press Temp Enth	Temp LMTD U	kJ/hr kJ/hr
	kg/hr k-Pa deg-C kJ/kg	deg-C del-C kJ/hm2	
SHT-I	Y In: 839743.5 Out: 839743.5	18618. 18013.	1.000 427.5
Soot	N In: 20685. Out: 20685.	176.7 176.7	759.30 726.9
RHT-II	Y In: 963688.3 Out: 963688.3	3895.8 3834.1	402.6 549.8
SH-III	Y In: 926239.7 Out: 926239.7	17428. 16907.	471.9 547.6
SH-II	Y In: 924388.6 Out: 924388.6	18013. 17428.	378.1 478.6
Boiler	Y In: 841443.5 Out: 841443.5	21861. 18618.	349.0 1.000

Appendix A: Typical Lignite Steam Generator

H E A T T R A N S F E R D A T A (F4 SCREEN)

ID of Heat Exchg	Fg Fact //Flow<0)	Surface Area m^2	Flow X-Area m^2	Gas Recir Fract	Gas Path/ Split	Working Fluid U=F*A*Gw**B F*A	Working Fluid B	Gas Convection U=A*Gg**B A	Gas Convection B	Gas Convection & Rad. C	Gas Convection & Rad. D
IDFan					1/1.000						
STM					1/1.000						
AIR					1/1.000						
Econ	.200000	184313.	9.2903		1/1.000	.01582	.80	5.93551			
RHT-I	.700000	9255.00	9.2903		1/1.000	.01485	.80	3.84741			
SHT-I	2.8	4784.79	9.2903		1/1.000	.01452	.80	3.66648			
Soot					1/1.000						
RHT-II	.350000	38829.8	9.2903		1/1.000	.01466	.80	3.50097			
SH-III	.350000	44060.2	9.2903		1/1.000	.01523	.80	4.82918			
SH-II	.350000	37161.2	9.2903		1/1.000	.01285	.80	2.51214			
Boiler	.350000	37161.2	9.2903		1/1.000	.01162	.80	4.87963			

TEST MODE (in KU units) --

(H = kJ/kg-AF; T = deg-K)

Test No.	Fuel Flow	W.F. Parameters	Heat Transfer	H = J + K*T + L*T*T/1000
1-A	503597.74	All Data Present	All Data Present	-1331.75 4.117087 .6241729
2-A&C	.00000000	No Data Entered	No Data Entered	.00000000 .00000000 .00000000
3-ABC&D	.00000000	No Data Entered	No Data Entered	.00000000 .00000000 .00000000

M I S C E L L A N E O U S D A T A

Dry Air/Fuel theo. combustion:	2.53674	Stoic Error:a*delta-phi(PCent):	.00000
Wet Air/Fuel at the combustor:	2.96916	Stoic Error: delta-a (PCent):	.00000
Wet Air/Fuel at boundary, I/L:	3.44105	Reference Input Air O2 (Fract):	.209480
Excess Air - Actual (Fract):	.163465	Reference Stoic.Air O2 (Fract):	.209480
Excess Air - Tuned (Fract):	.194497	Ref. phi Based on Input(Fract):	3.77373
EA w/o Leakage per Theor. Air:	.348375		
Mol. Weight of Dry Boiler Gas:	30.8775	Error in BAE/Eff. Diff.(Fract):	.000000
Mol. Weight of As-Fired Fuel:	17.2775	Error in BAE/Mass Flows(Fract):	.000000
APH Dilution Factor, beta:	.1589310	Error in BAE/F7 Input (Fract):	.000000
APH Leakage Factor, script-R:	1.160568	Error in BAE/Complement(Fract):	.020376
Most-Ash-Gas-Free Fuel Moles:	24.28282	Error in Ref. Fuel Flow(kg/hr):	-.00542
Wet Air Leakage/Wet Gas, Wt.:	.1252687		
Ash via F2 times Fuel (Moles):	2.40849	Wet Bulb Temperature (deg-C):	10.4039
Ash via F2 inputs (Wt. Fract):	.198140	Rel Humidity Comb. Air (Fract):	.568978
Ash via F7 inputs (Wt. Fract):	.166583	Sp. Humidity Comb. Air(kg/kgDA):	.006016
Ash to combustion (Wt. Fract):	.198140	Sat. Moist Air Enthalpy(kJ/kg):	2528.83
Carbon in Average Compound, YR:	.000000	Sp. Volume of Comb. Air(m^3/kg):	.824033
Hydrogen in Avg. Compound, ZR:	.000000	Boiler Acid Dew Point (deg-C):	163.914
Gaseous Fuel, alpha-0 (Fract):	.000000	Boiler Water Dew Point (deg-C):	35.4709
FD FanPower via F5/6 (kJ/hr):	.000000	Adiabatic Flame Temp. (deg-C):	1162.10
ID FanPower via F5/6 (kJ/hr):	6469380	Effect.Adb.Flame, EAFT (deg-C):	1162.10
Wet Gas Den./EPA ((kg/DSm^3):	1.15011	Predicted Fuel NOx (ppm@3%):	664.818
Wet Stack Flow (std-m^3/min):	30935.1	Pred.Thermal NOx @ EAFT(ppm@3%):	.217851

Appendix A: Typical Lignite Steam Generator

S U M M A R Y O F B O I L E R L O S S E S			Page 5A of 6B
	Eff.Term		System
STACK LOSSES (Effects LHV Combustion Efficiency), %	Effect		Effect
Dry Stack Gas Loss, L-G	7.193939		7.193939
Moisture Created from Combustion, L-mG	.5439207		.5439207
Moisture in As-Fired Fuel, L-mF	1.792812		1.792812
Moisture from Burning Hydrogen Gas, L-H	.0000000		.0000000
Moisture from Combustion Air, L-mA	.0772435		.0772435
Moisture from In-Leakage, Misc, L-z & L-Ca	.0000000		.0000000
Unburned Fuel in Stack, L-CO, L-UH & L-UHC	.0000000		.0000000
Unburned Carbon in Bottom Ash, L-UC1	1.924525		1.924525
Unburned Carbon in Fly Ash, L-UC2	.1751244		.1751244
TOTAL STACK LOSSES (LHV)	11.70756		11.70756
SENSIBLE HEAT LOSSES (Effects LHV Absorption Eff.), %			
Radiation & Conv. Loss (HHVP+HBC), L-beta	.7034935		.6211315
Total Ash Pit Losses, L-p	1.346022		1.188436
Dust/Ash Heat Loss @ Precip/Stack, L-d/ash	.2222571		.1962362
CaSO4.zH2O & CaO Loss @ Precip., L-d/Ca	.0000000		.0000000
Heat Loss in Pulverizer Rejects, L-r	.0000000		.0000000
Adjustment for Induced Draft Fans, W-id	-.2341266		-.2067160
Based on Direct Input of Absorption Eff.	.0000000		.0000000
TOTAL SENSIBLE LOSSES (LHV)	2.037646		1.799087
TOTAL SYSTEM LOSSES (LHV)			13.50665

S U M M A R Y O F A I R C O M P O N E N T S			Page 5B of 6B
AIR PRE-HEATER (Type 5):			
		03	
Air Energy Flow	(kJ/hr)	.38182E9	
Air Temperature Rise	(deltaC)	249.2137	
Gas Efficiency	(Fract)	.5349598	
X-Ratio per PTC 4.3	(Fract)	.6380319	
Wet Air Lkg/Wet Gas	(Fract)	.1252687	
Gas Temp Drop w/o Lkg	(deltaC)	159.0063	
Temperature Head	(deltaC)	297.2303	
Cold-End Avg Temp	(deg-C)	99.89832	
Average Moist Air Cp	(kJ/kgK)	1.024643	
Wet Gas Cp w/o Lkg	(kJ/kgK)	1.265796	
Undiluted Gas Temp	(deg-C)	169.0103	
Diluted Gas Temp	(deg-C)	156.0841	
STEAM/AIR HEATER (Type 6):			
		02	
Air Energy Flow	(kJ/hr)	.0000000	
Air Temperature Rise	(deltaC)	.0000000	
FD/ID FAN (Type 7 or 8):			
		01	
Component Type		Induced	
Air/Gas Energy Flow	(kJ/hr)	6469380.	
Air/Gas Temp. Rise	(deltaC)	2.500000	
Mechanical Efficiency	(Fract)	.7500000	

Appendix A: Typical Lignite Steam Generator

S E C O N D L A W A N A L Y S I S						Page 6A of 6B	
ID of Heat Exchanger (Type)	Working Fluid Exergy (kJ/hr)	Flue Gas Exergy (kJ/hr)	IRR (kJ/hr)	EFFECT (PCent)	Rel. IRR (PCent)	LHV Heat Rate (kJ/kWh)	Fuel Consumption Index
IDFan	In: 6469380.4* Out: N/A	285780500 -287617682	4632199.	28.40	.1354	10.65	1.0275
STM	In: 7227450.2@ Out: -7227450.2@	.000000000# .000000000#	.00000000	.0000	.0000	.0000	.00000
AIR	In: 7227450.2@ Out: -145563376@	412399909 -273256452	807530.9	99.42	.0236	1.856	.17913
Econ	In: 234020115 Out: -433299071	635165164 -412399909	23486299	89.46	.6865	53.99	5.2097
RHT-I	In: .10234E10 Out: -.11053E10	729496964 -635165164	12496605	86.75	.3653	28.73	2.7720
Combustion:			.2324E10	47.86	67.95	5343.	515.61
Exergy In Fuel:		.44512E10					Fuel Chemistry:
Exergy In Air:		7227450.2					Internal Calcs
Total Exergy Out:		-.2134E10					Ref. State:
Legend:							Pres = 101.3250
IRR = Irreversibility; EFFECT = Effectiveness; @ = Air;							Temp = 29.96816
* = Shaft Power; # = Working Fluid; + = Boiler Effect.							Enth = 125.7457

S E C O N D L A W A N A L Y S I S						Page 6B of 6B	
ID of Heat Exchanger (Type)	Working Fluid Exergy (kJ/hr)	Flue Gas Exergy (kJ/hr)	IRR (kJ/hr)	EFFECT (PCent)	Rel. IRR (PCent)	LHV Heat Rate (kJ/kWh)	Fuel Consumption Index
SHT-I	In: 802449600 Out: -.10405E10	.10184E10 -729496964	50776954	82.42	1.484	116.7	11.263
Soot	In: .000000000 Out: .000000000	.10184E10 -.10184E10	.00000000	.0000	.0000	.0000	.00000
RHT-II	In: .11265E10 Out: -.13187E10	.12453E10 -.10184E10	34711965	84.70	1.015	79.79	7.6998
SH-III	In: .12373E10 Out: -.13674E10	.14019E10 -.12453E10	26523692	83.07	.7753	60.97	5.8835
SH-II	In: .10123E10 Out: -.12469E10	.17141E10 -.14019E10	77601289	75.14	2.268	178.4	17.213
Boiler	In: 433299071 Out: -804074119	.26079E10 -.17141E10	.17492E9	67.94	5.113	402.1	38.802
Mixing Loss:	N/A	N/A	.00000000	N/A	.0000	.0000	.00000
Stack Loss:	N/A	287617682	.28761E9	32.10+	8.407	661.1	63.799
Environment:	N/A	N/A	.00000000	N/A	.0000	-1100	.00000
Elec Power:	-.1087E10	43200000.*	N/A	75.14	N/A	3600.	241.16
Misc TG Cycle:	N/A	.14469E10#	.40291E9	N/A	11.78	926.2	89.375

Sys Totals:	-.2672E10	.64415E10	.3421E10	24.12	100.0	10362	1000.0

APPENDIX B3-UNA:

**Steam Generator Report on the
Dissertation's Un-Adjusted Refuse Data
(abridged report)**

S T E A M G E N E R A T O R P E R F O R M A N C E R E P O R T

Check of Dissertation UN-Adjusted Refuse

Off-Line using LHV

Contents	Page
Title, Approvals & Input	1A&B
Mass/Energy Balances	2A
Stoichiometrics	2B
Turbine Cycle Data	3A&B
Heat Transfer Data	4A
Miscellaneous Data	4B
Summary of Boiler Losses	5A
Summary of Air Components	5B
Second Law Analyses	6A&B
Input File: REF-UNA.INP	
Output File: REF-UNA.INP	
Report File: REF-UNA.ESI	

Analysis produced by: EX-FOSS, Ver.2.8/Mod.18
 (c) 2009 by Exergetic Systems 415-455-0100
 12 San Marino Dr., San Rafael Calif. 94901
 Responsible Engineer:
 Date: _____
 Supervising Engineer:
 Date: _____
 Time and Date of Analysis: 14:22 on 09/09/08

HEAT TRANSFER RESULTS/RECOMMENDATIONS --
 FDFan
 AIR

LHV EFFICIENCIES & VAR. --
 Combustion: .79506 +/-0.00814
 Absorption: .97932 +/-0.00340
 Boiler: .77862 +/-0.01153

BOILER

I N P U T D A T A

Page 1B of 6B

F2 INPUT --
 Fuel: Coal (1)
 Ctrl: Stack CO Trim for EA Recomm. (1)
 Excess Air, Ctrl = 4 (Fract): .664206
 Higher Heating Value (kJ/kg):9084.675
 Lower Heating Value *(kJ/kg):7891.178
 Dry Bulb Temperature (deg-C): 25.8300
 Wet Bulb / Rel. Humd.(C/Frac): .200000
 Ref O2 Fract. in Air (Fract): .209500
 Fuel Specific Gravity(Fract): 1.00000
 Fuel Pressure (k-Pa): 100.311
 Fuel Temperature (deg-C): 25.8000
 Atmospheric Pressure (k-Pa): 101.350
 Ref Fuel Calorimetric(deg-C): 25.0000

 F3 INPUT --
 Flue Gas Pressure (k-Pa): 101.324
 Flue Gas Temperature (deg-C): 228.370
 Actual Adiabatic Temp(deg-C): 2159.05
 Targeted O2/-CO Trim (Fract): .000000
 Ratio of SO3/SO2 (Fract):
 Ratio of NO/NOx (Fract): 1.00000
 Ratio ESP SO2 Out/In (Fract): 1.00000
 Ratio APH Gas In/Out (Fract): 1.00000

F4 INPUT --
 Heat Transfer Mode: Monitoring (1)
 Cleanliness Cutoff: 1
 Applicable Eq: 2 Calc.Option/Test No: 1

 F7 INPUT --
 Calc or Ref Fuel Flow (kg/hr): 13889.05
 Loss from Rad. & Conv.(Fract): .0118412
 Bottom Ash/Fuel Flow (Fract): -.248703
 Carbon/Bottom Ash (Fract): .0240000
 Fly Ash/Fuel Flow (Fract): -.021933
 Carbon/Fly Ash Ratio (Fract): .0440000
 Sp. Heat of Refuse (kJ/kgK): .8700000
 Dry Bottom Ash Temp. (deg-C): 110.0000
 Rejects/Fuel Flow (Fract):
 Rejects Uncorr. LHV (kJ/kg):
 Dust/Fuel Flow Ratio (Fract): .0211484
 Sp. Heat of Fly Ash (kJ/kgK): .9200000
 Gross Unit Ele. Power (kWe): 10.00000
 Summation Pump Power (kWe): .2000000
 Circ. or Makeup Flow (kg/hr): 1360777.
 Circ. Water Temp. (deg-C): 25.00000
 Tower Moist Air Flow (m^3/h):
 Boiler Power Input Bx (kJ/hr):

Appendix B3-UNA: Un-Adjusted Refuse Data

Page 2A of 6B

M A S S / E N E R G Y B A L A N C E S

LHV ENERGY BALANCE (kJ per kg As-Fired) --

Corrected Lower Heating Value LHVP	7824.211
Heat in As-Fired Fuel Flow	+ 1.386201
Heat in Dry Air & Moisture	+ 4.593949
Water/Steam Leakage (F5/6)	+ .0000000
Heat in LS, Stm-Air, FDFans	+ 40.75550
Boiler Firing Corrections, HBC	+ 46.73384
-> TOTAL FUEL AND SYSTEM INPUT	= 7870.945
Energy in Combustion Products (w/Stack Losses), HPR	11469.13
Energy in As-Fired Reactants (Fuel, Air & LS), HRX	- 5211.263
Total Energy Released During Combustion, ERC/WWFUEL	= 6257.864
Gross Boiler Non-Chemical & Sensible Heat Losses, HNSL	- 129.4123
Total Heat Delivered to Working Fluid, BBTCYC/WWFUEL	= 6128.451
Gross Boiler Stack and Sensible Heat Losses, HSL + HNSL	+ 1742.493
-> TOTAL GROSS STEAM GENERATOR ENERGY OUTPUT	= 7870.945

MASS FLOW BALANCE (kg/hr) --	Boiler Dry Gas Flow	79394.07
Calc. As-Fired Fuel Flow, WWFUEL	Boiler Moisture	+ 7475.444
Pulverizer Rejected Fuel Flow	Wet Air Heater Leakage	+ .0000000
Inlet Combustion Dry Air Flow	Pulverizer Rejected Fuel	+ .0000000
Inlet Combustion Air Moisture	Limestone Products	+ .0000000
In-Leakage of Water & Steam Flow	Carbon in Bott & Fly Ash	+ 93.90244
Inlet or calc Limestone (CaCO3)	Ash with SO2 Capture (F2)	+ 3665.079
-> TOTAL INLET FLOW TO BOILER	= 90320.65	-> TOTAL OUTLET FLOW = 90628.50

Page 2B of 6B

S T O I C H I O M E T R I C S

	DRY GASEOUS PRODUCTS (%)	AIR PH INLET	OUTLET
AS-FIRED FUEL (weight fractions, unadjusted input)	Carbon Dioxide +	11.40000	11.40000
Nitrogen	Comb. Oxygen +	8.800000	8.800000
Water	Comb. Nitrogen +	79.63499	79.63499
Oxygen	Comb. Moisture	15.79870	15.79870
Carbon	Sulfur Dioxide +	.0971335	.0971335
Hydrogen	SO2 Ash Capture	.0000000	.0000000
Sulfur	Carbon in Ash	.2976618	.2976618
Carbon Dioxide	Ash (from F2)	1.993475	1.993475
Carbon Monoxide	Sulfur Trioxide +	.0000000	.0000000
Chlorine	Carbon Monoxide +	.0020000	.0020000
Ash (F2 input)	NOx (combined) +	.0000000	.0000000
ID =	Free Hydrogen +	.0000000	.0000000
ID =	ID = 45 +	.0658775	.0658775
ID =	ID = +	.0000000	.0000000
ID =	Leakage Oxygen +		.0000000
ID =	Leakage Nitrogen +		.0000000
ID =	Leakage Moisture		.0000000
ID =	-> TOTAL MOLES DRY GAS (+)	100.0000	100.0000
ID =	As-Fired Fuel/100 Mole Dry Gas Base, x	= 32.71656	
ID =	Inlet Oxygen at Boundary, a*(1 + beta)	= 21.04611	
ID =	Inlet Air Moisture [F2], bA*(1 + beta)	= .6642570	
ID =	In-Leakage of Water & Steam [F5/6], bZ	= .0000000	
-> TOTAL FUEL WT = 1.0000000	Inlet Pure Limestone, bPLS*(1 + gamma)	= .0000000	

Note: ID = 45 is HCl.

Appendix B3-UNA: Un-Adjusted Refuse Data

T U R B I N E C Y C L E D A T A (F5 SCREEN)

Page 3A of 6B

ID of Interface Heat Exchg (Type)	Flags		Monitoring or Test Data for Gas, Air & Working Fl				Heat Exchanger		Energy Transferred		
	T-G	S-G	Flow	Press	Temp	Enth	Temp	LMTD	U	from Gas	to Work.Fl.
(Y/N)	I/O		kg/hr	k-Pa	deg-C	kJ/kg	deg-C	del-C	kJ/hm2	kJ/hr	kJ/hr
FDfan	N	In:	76431.59	100.31	25.83	36.386					
		Out:	76431.59	101.31	33.16	43.792					
AIR	N	In:	76431.59	101.31	33.16	43.791	228.4			7370562.	
		Out:	76431.59	100.31	128.2	140.22	302.9				
	N	In:									
		Out:									
BOILER	Y	In:	38046.00	3581.0	130.0	548.55	302.9			86138393	85118405
		Out:	38046.00	3074.0	.9900	2785.8	1095.				
	N	In:									
		Out:									
	N	In:									
		Out:									

T U R B I N E C Y C L E D A T A (F6 SCREEN)

Page 3B of 6B

ID of Interface Heat Exchg (Type)	Flags		Monitoring or Test Data for Gas, Air & Working Fl				Heat Exchanger		Energy Transferred		
	T-G	S-G	Flow	Press	Temp	Enth	Temp	LMTD	U	from Gas	to Work.Fl.
(Y/N)	I/O		kg/hr	k-Pa	deg-C	kJ/kg	deg-C	del-C	kJ/hm2	kJ/hr	kJ/hr
	N	In:									
		Out:									
	N	In:									
		Out:									
	N	In:									
		Out:									
	N	In:									
		Out:									
	N	In:									
		Out:									

Appendix B3-UNA: Un-Adjusted Refuse Data

H E A T T R A N S F E R D A T A (F4 SCREEN)

ID of Heat Exchg	Fg Fact (X-Flow>0 //Flow<0)	Surface Area m^2	Flow X-Area m^2	Gas Recir Fract	Path/ Split	Working Fluid U=F*A*Gw**B F*A B	Gas Convection U=A*Gg**B A B	& Rad. + C*LMTD + D C D
FDfan						1/1.000		
AIR						1/1.000		
BOILER						1/1.000		

MONITORING MODE (in KU units) -- (H = kJ/kg-AF; T = deg-K)

Test No.	Fuel Flow	W.F. Parameters	Heat Transfer	H = J + K*T + L*T*T/1000
1-A	13889.057	No Data Needed	No Data Needed	-1945.26 6.240352 .8194501
2-A&C	.00000000	No Data Needed	No Data Needed	.00000000 .00000000 .00000000
3-ABC&D	.00000000	No Data Needed	No Data Needed	.00000000 .00000000 .00000000

M I S C E L L A N E O U S D A T A

Dry Air/Fuel theo. combustion:	3.29309	Stoic Error:a*delta-phi(PCent):	-.35886
Wet Air/Fuel at the combustor:	5.50301	Stoic Error: delta-a (PCent):	-.36629
Wet Air/Fuel at boundary, I/L:	5.50301	Reference Input Air O2 (Fract):	.209500
Excess Air - Actual (Fract):	.664206	Reference Stoic.Air O2 (Fract):	.212362
Excess Air - Tuned (Fract):	.002275	Ref. phi Based on Input(Fract):	3.77327
EA w/o Leakage per Theor. Air:	.664206		
Mol. Weight of Dry Boiler Gas:	30.2283	Error in BAE/Eff. Diff.(Fract):	.000000
Mol. Weight of As-Fired Fuel:	16.1633	Error in BAE/Mass Flows(Fract):	.003397
APH Dilution Factor, beta:	.0000000	Error in BAE/F7 Input (Fract):	.000000
APH Leakage Factor, script-R:	1.000000	Error in BAE/Complement(Fract):	.020680
Most-Ash-Gas-Free Fuel Moles:	24.79152	Error in Ref. Fuel Flow(kg/hr):	.000000
Wet Air Leakage/Wet Gas, Wt.:	.0000000		
Ash via F2 times Fuel (Moles):	1.99347	Wet Bulb Temperature (deg-C):	13.0060
Ash via F2 inputs (Wt. Fract):	.263883	Rel Humidity Comb. Air (Fract):	.200000
Ash via F7 inputs (Wt. Fract):	.263702	Sp. Humidity Comb. Air(kg/kgDA):	.004129
Ash to combustion (Wt. Fract):	.263883	Sat. Moist Air Enthalpy(kJ/kg):	2548.70
Carbon in Average Compound, YR:	.000000	Sp. Volume of Comb. Air(m^3/kg):	.852396
Hydrogen in Avg. Compound, ZR:	.000000	Boiler Acid Dew Point (deg-C):	
Gaseous Fuel, alpha-0 (Fract):	.000000	Boiler Water Dew Point (deg-C):	32.2273
FD FanPower via F5/6 (kJ/hr):	566055.	Adiabatic Flame Temp. (deg-C):	1032.77
ID FanPower via F5/6 (kJ/hr):	.000000	Effect.Adb.Flame, EAFT (deg-C):	1032.77
Wet Gas Den./EPA ((kg/DSm^3):	1.18737	Predicted Fuel NOx (ppm@3%):	1313.93
Wet Stack Flow (std-m^3/min):	1219.36	Pred.Thermal NOx @ EAFT(ppm@3%):	.083706

APPENDIX B3-ADJ:

**Steam Generator Report on the
Dissertation's Adjusted Refuse Data,
(abridged report)**

S T E A M G E N E R A T O R P E R F O R M A N C E R E P O R T

Check of Dissertation Adjusted Refuse B3

Off-Line using LHV

Contents	Page
Title, Approvals & Input	1A&B
Mass/Energy Balances	2A
Stoichiometrics	2B
Turbine Cycle Data	3A&B
Heat Transfer Data	4A
Miscellaneous Data	4B
Summary of Boiler Losses	5A
Summary of Air Components	5B
Second Law Analyses	6A&B
Input File: REF-ADJ.INP	
Output File: REF-ADJ.INP	
Report File: REF-ADJ.ESI	

Analysis produced by: EX-FOSS, Ver.2.8/Mod.18
(c) 2009 by Exergetic Systems 415-455-0100
12 San Marino Dr., San Rafael Calif. 94901
Responsible Engineer:
Date: _____
Supervising Engineer:
Date: _____
Time and Date of Analysis: 16:27 on 09/09/08
HEAT TRANSFER RESULTS/RECOMMENDATIONS --
FDfan
AIR

LHV EFFICIENCIES & VAR. --
Combustion: .80432 +/- .01154
Absorption: .97948 +/- .00508
Boiler: .78782 +/- .01662

BOILER

I N P U T D A T A

F2 INPUT --
Fuel: Coal (1)
Ctrl: Stack CO Trim for EA Recomm. (1)
Excess Air, Ctrl = 4 (Fract): .620802
Higher Heating Value (kJ/kg):9223.781
Lower Heating Value *(kJ/kg):8020.991
Dry Bulb Temperature (deg-C): 25.8387
Wet Bulb / Rel. Humd.(C/Frac): .200000
Ref O2 Fract. in Air (Fract): .209500
Fuel Specific Gravity(Fract): 1.00000
Fuel Pressure (k-Pa): 100.311
Fuel Temperature (deg-C): 25.8000
Atmospheric Pressure (k-Pa): 101.350
Ref Fuel Calorimetric(deg-C): 25.0000

F3 INPUT --
Flue Gas Pressure (k-Pa): 101.324
Flue Gas Temperature (deg-C): 228.370
Actual Adiabatic Temp(deg-C): 2159.05
Targeted O2/-CO Trim (Fract): .000000
Ratio of SO3/SO2 (Fract):
Ratio of NO/NOx (Fract): 1.00000
Ratio ESP SO2 Out/In (Fract): 1.00000
Ratio APH Gas In/Out (Fract): 1.00000

F4 INPUT --
Heat Transfer Mode: Monitoring (1)
Cleanliness Cutoff: 1
Applicable Eq: 2 Calc.Option/Test No: 1

F7 INPUT --
Calc or Ref Fuel Flow (kg/hr): 13502.79
Loss from Rad. & Conv.(Fract): .0118504
Bottom Ash/Fuel Flow (Fract): -.248703
Carbon/Bottom Ash (Fract): .0240000
Fly Ash/Fuel Flow (Fract): -.021933
Carbon/Fly Ash Ratio (Fract): .0440000
Sp. Heat of Refuse (kJ/kgK): .8700000
Dry Bottom Ash Temp. (deg-C): 110.0000
Rejects/Fuel Flow (Fract):
Rejects Uncorr. LHV (kJ/kg):
Dust/Fuel Flow Ratio (Fract): .0275874
Sp. Heat of Fly Ash (kJ/kgK): .9200000
Gross Unit Ele. Power (kWe): 10.00000
Summation Pump Power (kWe): .2000000
Circ. or Makeup Flow (kg/hr): 1360777.
Circ. Water Temp. (deg-C): 25.00000
Tower Moist Air Flow (m^3/h):
Boiler Power Input Bx (kJ/hr):

Appendix B3-ADJ: Adjusted Refuse Data

Page 2A of 6B

M A S S / E N E R G Y B A L A N C E S

LHV ENERGY BALANCE (kJ per kg As-Fired) --

Corrected Lower Heating Value LHV	7953.680		
Heat in As-Fired Fuel Flow	+ 1.390059		
Heat in Dry Air & Moisture	+ 4.420280		
Water/Steam Leakage (F5/6)	+ .0000000		
Heat in LS, Stm-Air, FDFans	+ 38.74924		
Boiler Firing Corrections, HBC	+ 44.55816		
-> TOTAL FUEL AND SYSTEM INPUT	= 7998.238		
Energy in Combustion Products (w/Stack Losses), HPR	11314.20		
Energy in As-Fired Reactants (Fuel, Air & LS), HRX	- 4881.074		
Total Energy Released During Combustion, ERC/WWFUEL	= 6433.126		
Gross Boiler Non-Chemical & Sensible Heat Losses, HNSL	- 131.9865		
Total Heat Delivered to Working Fluid, BBTCYC/WWFUEL	= 6301.140		
Gross Boiler Stack and Sensible Heat Losses, HSL + HNSL	+ 1697.098		
-> TOTAL GROSS STEAM GENERATOR ENERGY OUTPUT	= 7998.238		

MASS FLOW BALANCE (kg/hr) --		Boiler Dry Gas Flow	73635.55
Calc. As-Fired Fuel Flow, WWFUEL	13502.79	Boiler Moisture	+ 7309.256
Pulverizer Rejected Fuel Flow	+ .0000000	Wet Air Heater Leakage	+ .0000000
Inlet Combustion Dry Air Flow	+ 70464.01	Pulverizer Rejected Fuel	+ .0000000
Inlet Combustion Air Moisture	+ 291.1127	Limestone Products	+ .0000000
In-Leakage of Water & Steam Flow	+ .0000000	Carbon in Bott & Fly Ash	+ 93.51852
Inlet or calc Limestone (CaCO3)	+ .0000000	Ash with SO2 Capture (F2)	+ 3650.095
-> TOTAL INLET FLOW TO BOILER	= 84257.91	-> TOTAL OUTLET FLOW	= 84688.42

Page 2B of 6B

S T O I C H I O M E T R I C S DRY GASEOUS AIR PH INLET OUTLET

AS-FIRED FUEL (weight fractions, unadjusted input)	PRODUCTS (%)		
Nitrogen .0117259	Carbon Dioxide +	11.63000	11.63000
Water .2023326	Comb. Oxygen +	8.640000	8.640000
Oxygen .2117600	Comb. Nitrogen +	79.57074	79.57074
Carbon .2587367	Comb. Moisture	16.67124	16.67124
Hydrogen .0356375	Sulfur Dioxide +	.0920573	.0920573
Sulfur .0053194	SO2 Ash Capture	.0000000	.0000000
Carbon Dioxide .0000000	Carbon in Ash	.3199293	.3199293
Carbon Monoxide .0000000	Ash (from F2)	2.142603	2.142603
Chlorine .0041665	Sulfur Trioxide +	.0000000	.0000000
Ash (F2 input) .2703215	Carbon Monoxide +	.0020000	.0020000
ID = .0000000	NOx (combined) +	.0000000	.0000000
ID = .0000000	Free Hydrogen +	.0000000	.0000000
ID = .0000000	ID = 45 +	.0652036	.0652036
ID = .0000000	ID = +	.0000000	.0000000
ID = .0000000	Leakage Oxygen +		.0000000
ID = .0000000	Leakage Nitrogen +		.0000000
ID = .0000000	Leakage Moisture		.0000000
ID = .0000000	-> TOTAL MOLES DRY GAS (+)	100.0000	100.0000
ID = .0000000	As-Fired Fuel/100 Mole Dry Gas Base, x	= 34.16301	
ID = .0000000	Inlet Oxygen at Boundary, a*(1 + beta)	= 21.02646	
ID = .0000000	Inlet Air Moisture [F2], bA*(1 + beta)	= .6639811	
ID = .0000000	In-Leakage of Water & Steam [F5/6], bZ	= .0000000	
-> TOTAL FUEL WT = 1.0000001	Inlet Pure Limestone, bPLS*(1 + gamma)	= .0000000	

Note: ID = 45 is HCl.

Appendix B3-ADJ: Adjusted Refuse Data

T U R B I N E C Y C L E D A T A (F5 SCREEN)

Page 3A of 6B

ID of Interface	Monitoring or Test Data						Heat Exchanger		Energy Transferred		
	Heat	Flags	for Gas, Air & Working Fl			Gas	Exchanger	from	to		
EXCHG (Type)	T-G Y/N	S-G I/O	Flow kg/hr	Press k-Pa	Temp deg-C	Enth kJ/kg	Temp deg-C	LMTD del-C	U kJ/hm2	Gas kJ/hr	Work.Fl. kJ/hr
FDfan	N	In:	70755.12	100.31	25.83	36.391					
		Out:	70755.12	101.31	33.15	43.786					
AIR	N	In:	70755.12	101.31	33.15	43.786	228.4			6823899.	
		Out:	70755.12	100.31	128.2	140.23	302.1				
	N	In:									
		Out:									
BOILER	Y	In:	38033.40	3743.0	129.6	546.96	302.1			86103335	85082975
		Out:	38033.40	3089.0	.9890	2784.0	1144.				
	N	In:									
		Out:									
	N	In:									
		Out:									

T U R B I N E C Y C L E D A T A (F6 SCREEN)

Page 3B of 6B

ID of Interface	Monitoring or Test Data						Heat Exchanger		Energy Transferred		
	Heat	Flags	for Gas, Air & Working Fl			Gas	Exchanger	from	to		
EXCHG (Type)	T-G Y/N	S-G I/O	Flow kg/hr	Press k-Pa	Temp deg-C	Enth kJ/kg	Temp deg-C	LMTD del-C	U kJ/hm2	Gas kJ/hr	Work.Fl. kJ/hr
	N	In:									
		Out:									
	N	In:									
		Out:									
	N	In:									
		Out:									
	N	In:									
		Out:									
	N	In:									
		Out:									

Appendix B3-ADJ: Adjusted Refuse Data

H E A T T R A N S F E R D A T A (F4 SCREEN)

ID of Heat Exchg	Fg Fact (X-Flow>0 //Flow<0)	Surface Area m^2	Flow X-Area m^2	Gas Recir Fract	Path/ Split	Working Fluid U=F*A*Gw**B F*A B	Gas Convection U=A*Gg**B A B	& Rad. + C*LMTD + D C D
FDfan						1/1.000		
AIR						1/1.000		
BOILER						1/1.000		

MONITORING MODE (in KU units) -- (H = kJ/kg-AF; T = deg-K)

Test No.	Fuel Flow	W.F. Parameters	Heat Transfer	H = J + K*T + L*T*T/1000
1-A	13502.792	No Data Needed	No Data Needed	-1869.99 5.997387 .7926107
2-A&C	.00000000	No Data Needed	No Data Needed	.0000000 .0000000 .0000000
3-ABC&D	.00000000	No Data Needed	No Data Needed	.0000000 .0000000 .0000000

M I S C E L L A N E O U S D A T A

Dry Air/Fuel theo. combustion:	3.21969	Stoic Error:a*delta-phi(PCent):	-.53693
Wet Air/Fuel at the combustor:	5.24004	Stoic Error: delta-a (PCent):	-.55282
Wet Air/Fuel at boundary, I/L:	5.24004	Reference Input Air O2 (Fract):	.209500
Excess Air - Actual (Fract):	.620802	Reference Stoic.Air O2 (Fract):	.213816
Excess Air - Tuned (Fract):	-.00895	Ref. phi Based on Input(Fract):	3.77327
EA w/o Leakage per Theor. Air:	.620801		
Mol. Weight of Dry Boiler Gas:	30.2568	Error in BAE/Eff. Diff.(Fract):	.000000
Mol. Weight of As-Fired Fuel:	16.2406	Error in BAE/Mass Flows(Fract):	.005083
APH Dilution Factor, beta:	.0000000	Error in BAE/F7 Input (Fract):	.000000
APH Leakage Factor, script-R:	1.000000	Error in BAE/Complement(Fract):	.020517
Most-Ash-Gas-Free Fuel Moles:	25.75643	Error in Ref. Fuel Flow(kg/hr):	.000000
Wet Air Leakage/Wet Gas, Wt.:	.0000000		
Ash via F2 times Fuel (Moles):	2.14260	Wet Bulb Temperature (deg-C):	13.0115
Ash via F2 inputs (Wt. Fract):	.270322	Rel Humidity Comb. Air (Fract):	.200000
Ash via F7 inputs (Wt. Fract):	.263702	Sp. Humidity Comb. Air(kg/kgDA):	.004131
Ash to combustion (Wt. Fract):	.270322	Sat. Moist Air Enthalpy(kJ/kg):	2548.71
Carbon in Average Compound, YR:	.000000	Sp. Volume of Comb. Air(m^3/kg):	.852424
Hydrogen in Avg. Compound, ZR:	.000000	Boiler Acid Dew Point (deg-C):	
Gaseous Fuel, alpha-0 (Fract):	.000000	Boiler Water Dew Point (deg-C):	32.5089
FD FanPower via F5/6 (kJ/hr):	523223.	Adiabatic Flame Temp. (deg-C):	1083.57
ID FanPower via F5/6 (kJ/hr):	.000000	Effect.Adb.Flame, EAFT (deg-C):	1083.57
Wet Gas Den./EPA ((kg/DSm^3):	1.18511	Predicted Fuel NOx (ppm@3%):	1354.65
Wet Stack Flow (std-m^3/min):	1138.36	Pred.Thermal NOx @ EAFT(ppm@3%):	.121880

APPENDIX B3-ADF:

**Steam Generator Report on the
Dissertation's Adjusted Refuse Data
with Original Fuel
(abridged report)**

S T E A M G E N E R A T O R P E R F O R M A N C E R E P O R T

Check of Disser: Adjusted Case, Org.Fuel

Off-Line using LHV

Contents	Page
Title, Approvals & Input	1A&B
Mass/Energy Balances	2A
Stoichiometrics	2B
Turbine Cycle Data	3A&B
Heat Transfer Data	4A
Miscellaneous Data	4B
Summary of Boiler Losses	5A
Summary of Air Components	5B
Second Law Analyses	6A&B
Input File: REF-ADF.INP	
Output File: REF-ADF.INP	
Report File: REF-ADF.ESI	

Analysis produced by: EX-FOSS, Ver.2.8/Mod.18
 (c) 2009 by Exergetic Systems 415-455-0100
 12 San Marino Dr., San Rafael Calif. 94901
 Responsible Engineer:
 Date: _____
 Supervising Engineer:
 Date: _____
 Time and Date of Analysis: 16:26 on 09/09/08

HEAT TRANSFER RESULTS/RECOMMENDATIONS --
 FDFan
 AIR

LHV EFFICIENCIES & VAR. --
 Combustion: .80120 +/- .00011
 Absorption: .97956 +/- .00005
 Boiler: .78482 +/- .00017

BOILER

I N P U T D A T A

F2 INPUT --
 Fuel: Coal (1)
 Ctrl: Stack CO Trim for EA Recomm. (1)
 Excess Air, Ctrl = 4 (Fract): .637426
 Higher Heating Value (kJ/kg): 9214.488
 Lower Heating Value *(kJ/kg): 8020.991
 Dry Bulb Temperature (deg-C): 25.8387
 Wet Bulb / Rel. Humd.(C/Frac): .200000
 Ref O2 Fract. in Air (Fract): .209500
 Fuel Specific Gravity(Fract): 1.00000
 Fuel Pressure (k-Pa): 100.311
 Fuel Temperature (deg-C): 25.8000
 Atmospheric Pressure (k-Pa): 101.350
 Ref Fuel Calorimetric(deg-C): 25.0000

F3 INPUT --
 Flue Gas Pressure (k-Pa): 101.324
 Flue Gas Temperature (deg-C): 228.370
 Actual Adiabatic Temp(deg-C): 2159.05
 Targeted O2/-CO Trim (Fract): .000000
 Ratio of SO3/SO2 (Fract):
 Ratio of NO/NOx (Fract): 1.00000
 Ratio ESP SO2 Out/In (Fract): 1.00000
 Ratio APH Gas In/Out (Fract): 1.00000

F4 INPUT --
 Heat Transfer Mode: Monitoring (1)
 Cleanliness Cutoff: 1
 Applicable Eq: 2 Calc.Option/Test No: 1

F7 INPUT --
 Calc or Ref Fuel Flow (kg/hr): 13551.33
 Loss from Rad. & Conv.(Fract): .0118504
 Bottom Ash/Fuel Flow (Fract): -.248703
 Carbon/Bottom Ash (Fract): .0240000
 Fly Ash/Fuel Flow (Fract): -.021933
 Carbon/Fly Ash Ratio (Fract): .0440000
 Sp. Heat of Refuse (kJ/kgK): .8700000
 Dry Bottom Ash Temp. (deg-C): 110.0000
 Rejects/Fuel Flow (Fract):
 Rejects Uncorr. LHV (kJ/kg):
 Dust/Fuel Flow Ratio (Fract): .0211484
 Sp. Heat of Fly Ash (kJ/kgK): .9200000
 Gross Unit Ele. Power (kWe): 10.00000
 Summation Pump Power (kWe): .2000000
 Circ. or Makeup Flow (kg/hr): 1360777.
 Circ. Water Temp. (deg-C): 25.00000
 Tower Moist Air Flow (m^3/h):
 Boiler Power Input Bx (kJ/hr):

Appendix B3-ADF: Adjusted Refuse Data with Original Fuel

Page 2A of 6B

M A S S / E N E R G Y B A L A N C E S

LHV ENERGY BALANCE (kJ per kg As-Fired) --

Corrected Lower Heating Value LHVP		7954.024
Heat in As-Fired Fuel Flow	+ 1.386201	
Heat in Dry Air & Moisture	+ 4.567421	
Water/Steam Leakage (F5/6)	+ .0000000	
Heat in LS, Stm-Air, FDFans	+ 40.03912	
Boiler Firing Corrections, HBC	+ 45.99117	
-> TOTAL FUEL AND SYSTEM INPUT		= 8000.015
Energy in Combustion Products (w/Stack Losses), HPR		11491.79
Energy in As-Fired Reactants (Fuel, Air & LS), HRX		- 5082.193
Total Energy Released During Combustion, ERC/WWFUEL		= 6409.596
Gross Boiler Non-Chemical & Sensible Heat Losses, HNSL		- 131.0253
Total Heat Delivered to Working Fluid, BBTCYC/WWFUEL		= 6278.571
Gross Boiler Stack and Sensible Heat Losses, HSL + HNSL		+ 1721.444
-> TOTAL GROSS STEAM GENERATOR ENERGY OUTPUT		= 8000.015

MASS FLOW BALANCE (kg/hr) --		Boiler Dry Gas Flow	75972.65
Calc. As-Fired Fuel Flow, WWFUEL	13551.33	Boiler Moisture	+ 7288.892
Pulverizer Rejected Fuel Flow	+ .0000000	Wet Air Heater Leakage	+ .0000000
Inlet Combustion Dry Air Flow	+ 73071.33	Pulverizer Rejected Fuel	+ .0000000
Inlet Combustion Air Moisture	+ 301.8845	Limestone Products	+ .0000000
In-Leakage of Water & Steam Flow	+ .0000000	Carbon in Bott & Fly Ash	+ 91.61910
Inlet or calc Limestone (CaCO3)	+ .0000000	Ash with SO2 Capture (F2)	+ 3575.959
-> TOTAL INLET FLOW TO BOILER	= 86924.54	-> TOTAL OUTLET FLOW	= 86929.12

Page 2B of 6B

S T O I C H I O M E T R I C S DRY GASEOUS

		AIR PH INLET	OUTLET
AS-FIRED FUEL (weight fractions, unadjusted input)	PRODUCTS (%)		
Nitrogen .0117779	Carbon Dioxide +	11.63000	11.63000
Water .2009527	Comb. Oxygen +	8.264000	8.264000
Oxygen .2120093	Comb. Nitrogen +	79.93770	79.93770
Carbon .2657384	Comb. Moisture	16.10683	16.10683
Hydrogen .0353336	Sulfur Dioxide +	.0990928	.0990928
Sulfur .0058889	SO2 Ash Capture	.0000000	.0000000
Carbon Dioxide .0000000	Carbon in Ash	.3036662	.3036662
Carbon Monoxide .0000000	Ash (from F2)	2.033687	2.033687
Chlorine .0044167	Sulfur Trioxide +	.0000000	.0000000
Ash (F2 input) .2638825	Carbon Monoxide +	.0020000	.0020000
ID = .0000000	NOx (combined) +	.0000000	.0000000
ID = .0000000	Free Hydrogen +	.0000000	.0000000
ID = .0000000	ID = 45 +	.0672063	.0672063
ID = .0000000	ID = +	.0000000	.0000000
ID = .0000000	Leakage Oxygen +		.0000000
ID = .0000000	Leakage Nitrogen +		.0000000
ID = .0000000	Leakage Moisture		.0000000
ID = .0000000	-> TOTAL MOLES DRY GAS (+)	100.0000	100.0000
ID = .0000000	As-Fired Fuel/100 Mole Dry Gas Base, x	= 33.37652	
ID = .0000000	Inlet Oxygen at Boundary, a*(1 + beta)	= 21.12515	
ID = .0000000	Inlet Air Moisture [F2], bA*(1 + beta)	= .6670975	
ID = .0000000	In-Leakage of Water & Steam [F5/6], bZ	= .0000000	
-> TOTAL FUEL WT = 1.0000000	Inlet Pure Limestone, bPLS*(1 + gamma)	= .0000000	

Note: ID = 45 is HCl.

Appendix B3-ADF: Adjusted Refuse Data with Original Fuel

T U R B I N E C Y C L E D A T A (F5 SCREEN)

ID of Interface Heat ExchG (Type)	Interface		Monitoring or Test Data for Gas, Air & Working Fl				Heat Exchanger		Energy Transferred		
	T-G	S-G	Flow	Press	Temp	Enth	Temp	LMTD	U	from Gas	to Work.Fl.
	Y/N	I/O	kg/hr	k-Pa	deg-C	kJ/kg	deg-C	del-C	kJ/hm2	kJ/hr	kJ/hr
FDfan	N	In:	73373.21	100.31	25.83	36.391					
		Out:	73373.21	101.31	33.15	43.786					
AIR	N	In:	73373.21	101.31	33.15	43.786	228.4			7076398.	
		Out:	73373.21	100.31	128.2	140.23	302.9				
	N	In:									
		Out:									
BOILER	Y	In:	38033.40	3743.0	129.6	546.96	302.9			86103335	85082975
		Out:	38033.40	3089.0	.9890	2784.0	1125.				
	N	In:									
		Out:									
	N	In:									
		Out:									

T U R B I N E C Y C L E D A T A (F6 SCREEN)

ID of Interface Heat ExchG (Type)	Interface		Monitoring or Test Data for Gas, Air & Working Fl				Heat Exchanger		Energy Transferred		
	T-G	S-G	Flow	Press	Temp	Enth	Temp	LMTD	U	from Gas	to Work.Fl.
	Y/N	I/O	kg/hr	k-Pa	deg-C	kJ/kg	deg-C	del-C	kJ/hm2	kJ/hr	kJ/hr
	N	In:									
		Out:									
	N	In:									
		Out:									
	N	In:									
		Out:									
	N	In:									
		Out:									
	N	In:									
		Out:									
	N	In:									
		Out:									

Appendix B3-ADF: Adjusted Refuse Data with Original Fuel

H E A T T R A N S F E R D A T A (F4 SCREEN)

ID of Heat Exchg	Fg Fact (X-Flow>0 //Flow<0)	Surface Area m^2	Flow X-Area m^2	Gas Recir Fract	Working Fluid Path/ Split	U=F*A*Gw**B F*A B	Gas Convection U=A*Gg**B A B	& Rad. C*LMTD + D C D
FDfan					1/1.000			
AIR					1/1.000			
BOILER					1/1.000			

MONITORING MODE (in KU units) --

(H = kJ/kg-AF; T = deg-K)

Test No.	Fuel Flow	W.F. Parameters	Heat Transfer	H = J + K*T + L*T*T/1000
1-A	13551.330	No Data Needed	No Data Needed	-1913.11 6.136417 .8088320
2-A&C	.00000000	No Data Needed	No Data Needed	.0000000 .0000000 .0000000
3-ABC&D	.00000000	No Data Needed	No Data Needed	.0000000 .0000000 .0000000

M I S C E L L A N E O U S D A T A

Dry Air/Fuel theo. combustion:	3.29309	Stoic Error:a*delta-phi(PCent):	-.00567
Wet Air/Fuel at the combustor:	5.41447	Stoic Error: delta-a (PCent):	-.00569
Wet Air/Fuel at boundary, I/L:	5.41447	Reference Input Air O2 (Fract):	.209500
Excess Air - Actual (Fract):	.637426	Reference Stoic.Air O2 (Fract):	.209544
Excess Air - Tuned (Fract):	.018191	Ref. phi Based on Input(Fract):	3.77327
EA w/o Leakage per Theor. Air:	.637425		
Mol. Weight of Dry Boiler Gas:	30.2445	Error in BAE/Eff. Diff.(Fract):	.000000
Mol. Weight of As-Fired Fuel:	16.1633	Error in BAE/Mass Flows(Fract):	.000053
APH Dilution Factor, beta:	.0000000	Error in BAE/F7 Input (Fract):	.000000
APH Leakage Factor, script-R:	1.000000	Error in BAE/Complement(Fract):	.020442
Most-Ash-Gas-Free Fuel Moles:	25.29161	Error in Ref. Fuel Flow(kg/hr):	.000000
Wet Air Leakage/Wet Gas, Wt.:	.0000000		
Ash via F2 times Fuel (Moles):	2.03369	Wet Bulb Temperature (deg-C):	13.0115
Ash via F2 inputs (Wt. Fract):	.263883	Rel Humidity Comb. Air (Fract):	.200000
Ash via F7 inputs (Wt. Fract):	.263702	Sp. Humidity Comb. Air(kg/kgDA):	.004131
Ash to combustion (Wt. Fract):	.263883	Sat. Moist Air Enthalpy(kJ/kg):	2548.71
Carbon in Average Compound,YR:	.000000	Sp. Volume of Comb. Air(m^3/kg):	.852424
Hydrogen in Avg. Compound, ZR:	.000000	Boiler Acid Dew Point (deg-C):	
Gaseous Fuel, alpha-0 (Fract):	.000000	Boiler Water Dew Point (deg-C):	32.3296
FD FanPower via F5/6 (kJ/hr):	542583.	Adiabatic Flame Temp. (deg-C):	1063.17
ID FanPower via F5/6 (kJ/hr):	.000000	Effect.Adb.Flame, EAFT (deg-C):	1063.17
Wet Gas Den./EPA ((kg/DSm^3):	1.18679	Predicted Fuel NOx (ppm@3%):	1283.79