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A Real-Time Output–Loss Method for Monitoring Heat Rate for Coal-Fired Power Plants

This paper describes a real-time performance monitoring method based on PTC 4-2013 for determining instantaneous heat rates for coal-fired power plants. The calculation protocol uses a modified output–loss approach applied to a control volume that closely conforms to the boiler. The largest energy balance term is the heat transfer rate to the steam, which is known accurately in real-time when the plant employs properly calibrated instrumentation. The first-law energy balance also requires a balanced combustion equation which depends on coal composition, which is not known in real-time. A periodic or alert-driven calibration utilizes an ultimate analysis of a carefully collected coal sample and historic plant data obtained during the collection time of the coal sample. This is used to calculate correction factors for the coal mass flowrate, air preheater leakage, and CO_2 and SO_2 concentrations at the economizer exit derived from continuous emissions monitoring systems (CEMS) measurements performed at that location. The iterative calculations required to determine the coal composition in real-time are presented. The real-time performance algorithm exhibited significant sensitivity associated with measurements of the steam heat transfer rate, which was the dominant term in the overall boiler energy balance. Other input parameters generally yielded a much lower influence on calculated heat rate. It was concluded that for optimal accuracy of the output–loss method the steam and coal mass flowrates must be measured as accurately as possible. [DOI: 10.1115/1.4055627]

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Introduction

Heat rate is the parameter by which the performance of a coal-fueled electric generating unit (EGU) is evaluated. It is defined as the ratio of the rate at which energy is supplied to a unit to the power generated at that instant. The engineering units of heat rate are Btu/kW-h; such "mixed" units are prevalent throughout the power generation industry. Unit heat rate is a single-valued parameter; i.e., its assessment must yield a unique amount. The procedure for calculating the steam cycle heat rate appears to be uniform throughout the industry. However, the boiler efficiency that is calculated by the "loss method" does not follow a universal procedure, as acknowledged in ASME PTC 4. Many different values for the boiler efficiency are obtained for the same set of data, based on the choice of items to be included as output, items to be included as input, and the higher or lower heating value of the coal. Therefore, it is imperative to develop a standardized test method and calculation protocol for calculating the instantaneous heat rate in real-time. Once the instantaneous heat rate is available, hourly, daily, monthly, or annual values can be calculated.

This paper describes the equations used to characterize a real-time method to monitor the efficiency of coal-fired power plants. The method is based on PTC 4-2013 [1] and uses a modified output–loss approach applied to a control volume that closely conforms to the boiler. ASME PTC 4 requires the use of fuel analysis. However, most plants do not have the equipment to determine coal analysis on a real-time basis. This investigation demonstrates that it is possible to use CEMS data in lieu of coal analysis for calculating unit heat rate. A calibration procedure utilizes an ultimate analysis to describe the coal being burned during the calibration while holding the plant load and other factors steady. This permits the calculation of correction factors used during real-time performance monitoring, thereby yielding real-time estimates of coal composition and mass flowrate. Correction factors obtained from a calibration algorithm are used to adjust the CEMS measurements taken in the air preheater exit back to their values at the economizer exit, thereby accounting for dilution caused by air preheater leakage. Since the fuel composition is unknown, a series of iterative calculations are performed to back-calculate the coal composition, commencing from an initial estimate that the MAF coal is comprised entirely of carbon. The technique enables EGUs to utilize station CEMS data to monitor emissions and boiler control. It can easily be adopted in performance monitoring software, and thus provide real-time heat rate and CO_2/MW analysis by standalone computers, CEMS systems, or distributed control systems (DCS). The ultimate goal of this paper is to describe an output–loss method used to evaluate heat rate in real-time that can be incorporated into ASME code standards. With this output–loss method being based on ASME PTC 4, it can be readily compared with the results of an ASME PTC 4 test. Other available performance testing methods do not work in real-time. The sole way to validate the results from one method is to compare with another method. The unique contribution of the output–loss method is that it represents the only power plant performance measurement approach that works in real-time that can be validated in a consistent and accurate manner.

The output–loss method was developed in Refs. [2,3], and further refined as discussed in Refs. [4–16]. There are several important features associated with the output/loss method; it is the only method that considers the coupling between the cycle heat rate and the boiler efficiency. Thus, the unit heat rate is calculated uniquely and accurately. A real-time algorithm based on the output–loss method that requires only permanent station CEMS sensors was reported in Ref. [17]. Per that investigation, the calculation protocol employs an initial calibration procedure. The calibration process therein utilizes historical data obtained during a designated test period where coal samples are collected at regular intervals. The calibration algorithm uses a coal ultimate analysis to describe the coal being burned during the calibration while holding the plant load and other factors steady. This provides exact information related to coal composition, fuel moisture, loss on ignition (LOI), etc. Thereafter, CO and O_2 concentrations measured at the economizer exit are used to derive the balanced combustion equation. This permits the calculation of correction factors for the coal mass flowrate, air preheater leakage, and CO_2 and SO_2 concentrations at the economizer exit. These quantities are then supplied to a real-time performance monitoring algorithm [17]. The real-time algorithm (which is a CEMS-based method) employs measured CO_2, CO, SO_2, and O_2 concentrations in the flue gas to infer the coal composition instantaneously, even in the absence of a recent ultimate analysis. The losses are calculated in a manner that is analogous to PTC 4-2013 on a per-pound of as-fired coal basis, as opposed to a percentage of higher heating value (HHV) of the coal, since that information is presumably not known in real-time. Measurements of feedwater flowrate, and steam temperatures and pressures entering and leaving the boiler are utilized to evaluate the steam heat transfer, i.e., the output. Implementation of this method assumes sufficient plant instrumentation and knowledge of a specific plant, including steam extractions, etc., are known and quantifiable to permit the calculation of heat transferred to the steam in real-time. It is demonstrated in the present paper that such information is sufficient to evaluate the unit heat rate on a real-time basis. This paper also provides details concerning real-time loss calculations. It likewise describes the iterative calculations required to infer the coal composition in real-time.

A case study to validate the real-time algorithm was reported in Ref. [17]. Power plant performance predictions of heat rate from the real-time algorithm were found to compare very closely to test data obtained using PTC 4-2013 test methods. It was shown that real-time performance assessments of instantaneous plant heat rate could be improved if the most current coal ultimate analysis was utilized. Likewise, the modified F-factor method was used in conjunction with the real-time algorithm [18] to calculate the mass flowrate of CO_2 as a function of gross plant generation for a particular power plant. The resulting values were compared to similar data reported to EPA, but they did not demonstrate close agreement. The differences were attributed to the fact that the modified F-factor approach is based on actual conditions prevailing throughout the electric generation process, and does not rely on inaccurate stack gas volume flow measurements. However, the resulting heat rate values were identical to those obtained by a real-time performance monitoring algorithm, for the same input data.

Balanced Coal Combustion Reaction Equation

The output–loss method requires knowledge of the balanced chemical reaction equation for coal combustion with moist air. The composition of the coal being burned in an EGU can be determined by an ultimate analysis, but that procedure must be performed on a regular basis for the output–loss method to provide accurate predictions of boiler efficiency and heat rate. Even if the coal composition is presumably known from a recent ultimate analysis, the sample that was utilized for the measurement may not be entirely representative of the fuel being burned at any particular moment. Furthermore, the plant historian must be repeatedly updated to reflect the most current fuel composition. Hence there may be a limit on the accuracy of coal analyses in assessing combustion. The real-time algorithm of the output–loss method described in this paper provides means of estimating the coal composition by inference, based on prescribed CEMS measurements of flue gas species concentrations.

It is important to clearly establish the basis of coal composition measurements. Such analyses are often specified as follows: as-mined, as-fired, and as-received. Coal contains varying amounts of loosely held moisture and noncombustible materials (mineral ash). Two types of coal analyses are prevalent, i.e., proximate analysis and ultimate analysis. The experimental procedure employed in a proximate analysis is as follows: (i) a representative sample of coal is weighed, and then heated to a temperature sufficiently high to drive off the water, and then re-weighed: the fractional weight loss yields the coal moisture content "M," (ii) the remaining material is then heated to a much higher temperature in the absence of oxygen to drive off gases; the fractional weight loss yields the volatile matter content "VM," (iii) the remainder of the sample is then burned in the air until only noncombustibles remain; the fractional weight loss yields the fixed carbon content "FC," and (iv) the remaining material is identified as noncombustible mineral matter or ash "A." A proximate analysis is typically reported as percentages (or fractions) of the four quantities, i.e., moisture, volatile matter, fixed carbon, and ash. An ultimate coal analysis provides the elemental weight fractions of carbon, hydrogen, nitrogen, oxygen, and sulfur. Typically the ash content and heating value of the coal may also be provided. Data from a moisture and ash-free analysis can be converted to another basis by using the basis adjustment factor $\mathrm{MAF}=1-A-M$.

Coal Combustion. As a solid fuel, coal is typically burned by one of two methods. For stoker-fired boilers the coal is burned in chunk form on a stationary or moving grate; the air is usually supplied from below with combustion gasses passing upward and ash falling through the stationary grate (or dropping off the end of a moving grate). For pulverized coal boilers (PCB), coal is crushed to a fine particle size prior to firing; wall-mounted burners mix the coal particles with air and promote high turbulence to ensure thorough mixing and high combustion efficiency.

To obtain the balanced reaction equation for coal with moist air, the following assumptions are employed: (i) an excess of air is supplied, (ii) the formation of NO_x is disregarded, (iii) the unburned carbon is assumed to be known, and (iv) the composition of coal is known by means of an ultimate analysis. Therein as shown in Ref. [17], the balanced reaction equation per unit mole of carbon is given by

$$\begin{aligned}&\mathrm{CH}_a\mathrm{S}_b\mathrm{O}_c\mathrm{N}_d+f\,\mathrm{H_2O}+\beta(1+E)(\mathrm{O_2}+3.76\mathrm{N_2}+w\mathrm{H_2O})\\&\rightarrow(1-x-\alpha)\mathrm{CO_2}+x\mathrm{C}+\alpha\mathrm{CO}+\left[\frac{a}{2}+f+\beta(1+E)w\right]\mathrm{H_2O}+b\mathrm{SO_2}\\&+\left[\beta E+x+\frac{\alpha}{2}\right]\mathrm{O_2}+\left[3.76\beta(1+E)+\frac{d}{2}\right]\mathrm{N_2}\end{aligned}\tag{1}$$

The stoichiometric combustion air molar coefficient is given by

$$\beta=1+\frac{a}{4}+b-\frac{c}{2}\tag{2}$$

Since the combustion equation is derived on the basis of one mole of fuel carbon, it is understood that all molar coefficients are expressed per mole of fuel carbon.

The amount of excess air present in the combustion process is significant in characterizing combustion efficiency. Note that the presence of excess air implies there is more than the minimum amount of oxygen required for complete combustion. Its presence results in efficiency loss since the combustion energy released per unit mass of coal is constant, and that energy must then be used to heat the unused oxygen and accompanying nitrogen. Increasing the excess air reduces the flame temperature, which ultimately reduces the driving potential for heat transfer in the boiler. Every burner in the furnace requires some excess air to ensure the delivery and complete mixing of air and fuel and to maximize combustion of the fuel. If the coal composition is known by means of an ultimate analysis, and presuming CEMS data for $\%O_2$ and ppm CO is available at the economizer exit, and furthermore given knowledge of such auxiliary quantities as ambient air moisture and LOI, the molar coefficients for Eq. (1) can be determined. That yields sufficient information to evaluate the thermal losses associated with the boiler; which is discussed in more detail subsequently.

Output–Loss Method

This paper describes a calculation procedure (based on ASME PTC 4-2013) and a real-time performance monitoring method for determining and reporting EGU heat rate. The method can also be utilized in conjunction with a modified F-factor approach, as outlined in Ref. [18], to determine CO_2 emissions per MW of generation for fossil fuel power plants. A calibration algorithm utilizes coal composition data obtained from limited plant CEMS data and a current ultimate analysis to balance the coal combustion equation. Therein empirical correction factors for the coal mass flowrate and air preheater leakage are determined. Likewise, the calibration algorithm calculates additional correction factors that are used to convert CEMS concentration data for SO_2 and CO_2, performed downstream of the air preheater and before any scrubbers, back to their presumed values at the economizer outlet. It is noted that molar concentrations of the combustion products downstream of a scrubber are not representative of their values at the boiler exit. In every instance, the correction factors are provided to the real-time algorithm for further processing. A real-time algorithm utilizes the correction factors and CEMS data to analyze the composition of the combustion products at the control volume boundary of the boiler. Based on that knowledge, several terms in the combustion equation are approximated based on the most recent ultimate analysis, to deduce the as-fired coal composition and the coal mass flowrate in real-time.

A first-law energy balance on a control volume that conforms closely to the boiler of an SGU can be expressed as input = output + losses. Alternately this can be expressed as

$$\dot{m}_{\mathrm{coal}}\cdot\mathrm{HHV}=\dot{Q}_{\mathrm{steam}}+\mathrm{Lo}\tag{3}$$

In this instance, Lo implies thermal losses for the system, i.e., the coal fuel energy that is not transferred to the steam. The net measured heat transfer rate to the steam is denoted by $\dot{Q}_{\mathrm{steam}}$. Likewise, $\dot{m}_{\mathrm{coal}}$ refers to the coal mass flowrate, and HHV indicates the coal higher heating value. Equation (3) gives rise to the designation of the energy balance model described in this investigation as the output–loss method. Let ℓ denote the losses per unit mass of coal, such that

$$\ell=\frac{\mathrm{Lo}}{\dot{m}_{\mathrm{coal}}}\tag{4}$$

Hence, the energy balance on the boiler can also be expressed as follows:

$$\dot{m}_{\mathrm{coal}}\cdot\mathrm{HHV}=\dot{Q}_{\mathrm{steam}}+\dot{m}_{\mathrm{coal}}\cdot\ell\tag{5}$$

This paper describes a methodology to evaluate ℓ based on Ref. [1]. The following losses will be considered: (i) dry flue gas loss, (ii) moisture in air loss, (iii) fuel moisture loss, (iv) hydrogen burning loss, (v) unburned carbon loss, (vi) formation of CO loss, (vii) fly ash and bottom ash loss, and (viii) surface radiation and convection loss. Equation (5) implies that if the EGU output, i.e., $\dot{Q}_{\mathrm{steam}}$, is accurately measured, and if the losses per unit mass of coal ℓ can be correctly modeled, and supposing the fuel higher heating value is also known, then the coal mass flowrate $\dot{m}_{\mathrm{coal}}$ can be determined. The boiler efficiency of a coal-fired EGU is defined as

$$\eta_{\mathrm{B}}=\frac{\dot{Q}_{\mathrm{steam}}}{\dot{m}_{\mathrm{coal}}\cdot\mathrm{HHV}}\tag{6}$$

This quantity can also be expressed as

$$\eta_{\mathrm{B}}=1-\frac{\ell}{\mathrm{HHV}}\tag{7}$$

The steam cycle heat rate is defined as

$$\mathrm{HR_{Cycle}} = \frac{\dot{Q}_{\mathrm{steam}}}{\mathrm{KW_{Gross}}} \tag{8}$$

In this instance, $\mathrm{KW_G}$ connotes the plant gross generation. The gross unit heat rate is calculated as follows:

$$\mathrm{HR_{Gross}} = \frac{\dot{m}_{\mathrm{coal}} \cdot \mathrm{HHV}}{\mathrm{KW_{Gross}}} \tag{9}$$

Taking the station service power SS into account, the net unit heat rate is determined by

$$\mathrm{HR_{Net}} = \frac{\dot{m}_{\mathrm{coal}} \cdot \mathrm{HHV}}{\mathrm{KW_{Gross}} - \mathrm{SS}} = \frac{\mathrm{HR_{Cycle}}}{\eta_{\mathrm{B}}} \cdot \frac{\mathrm{KW_{Gross}}}{\mathrm{KW_{Gross}} - \mathrm{SS}} \tag{10}$$

Consider the schematic diagram of the system modeled by the output–loss method, as shown in Fig. 1. Flow rate, pressure, and temperature data for the feed water, main steam, cold reheat steam, and hot reheat steam are needed to calculate the steam heat transfer $\dot{Q}_{\mathrm{steam}}$. In many instances, the cold reheat steam flowrate is not measured directly. In such cases, it can be calculated by taking into account the extraction for the feed water heater. Likewise, it may be necessary to consider the utilization of attemperators in a power plant, which is used to control the temperature of superheated steam at various points throughout the cycle. Often this is accomplished by spraying water into a pipe located between superheater stages or upstream of a reheater inlet. Other coal-fired EGUs may have a different system diagram, and it is assumed that the thermodynamic analysis and sensor data are available to calculate an accurate value for $\dot{Q}_{\mathrm{steam}}$.

Output–Loss Method Energy Calculations. The thermal energy transfer terms associated with the boiler are evaluated with reference to Fig. 2, which depicts a control volume boundary surrounding the boiler. Under steady-state conditions, the first law of thermodynamics reduces to

$$\dot{E}_{\mathrm{in}} = \dot{E}_{\mathrm{out}} \tag{11}$$

Chemical energy is carried into the control volume by coal flow and then is released by combustion in the presence of moist air. Implicit in this investigation, the sensible energy of the coal entering the control volume is assumed to be negligible. However, sensible energy is conveyed into the control volume by the flow of dry combustion air, as well as due to the moisture present in both the fuel and air. A significant fraction of the fuel energy is used to provide heat to superheat the water flowing through the convection passes of the boiler. Additional energy is transported away from the control volume due to the flow of heated dry flue products, as well as with the fuel and combustion air moisture. Furthermore, sensible energy resulting from the chemical reaction of hydrogen in the fuel is advected from the control volume, along with the other flue gases. Other flows of energy from the control volume are attributed to ash flow, unburned carbon and carbon monoxide associated with incomplete combustion, and radiation and convection losses to the environment from the exposed surface of the boiler. Substituting the various energy transfer quantities into Eq. (11) and rearranging yields the following:

$$\begin{aligned}\dot{m}_{\mathrm{coal}} \cdot \mathrm{HHV} = {} & \dot{Q}_{\mathrm{steam}} + [(\dot{E}_{\mathrm{dry\ gases,out}} - \dot{E}_{\mathrm{dry\ air,in}}) \\ & + (\dot{E}_{\mathrm{H_2O,out}} - \dot{E}_{\mathrm{H_2O,in}}) + \dot{E}_{\mathrm{ash}} + \dot{E}_{\mathrm{unburned\ carbon}} \\ & + \dot{E}_{\mathrm{CO\ formation}} + \dot{Q}_{\mathrm{rad}}]\end{aligned} \tag{12}$$

The left-hand side of Eq. (12) denotes the "input," whereas $\dot{Q}_{\mathrm{steam}}$ represents the "output." The terms in square brackets indicate the "losses." As described subsequently, in this investigation the losses are calculated on a per unit mass of as-fired coal basis. Hence, the evaluation of energy loss rates is predicated on the assumption that either the coal mass flowrate is known or can be solved for algebraically. To calculate the losses per unit mass of coal, the balanced chemical reaction equation must first be obtained as outlined previously.

The quantity $\dot{Q}_{\mathrm{steam}}$ is the net heat transferred to the steam from the combustion products. This parameter is typically monitored closely by all power plants. The enthalpy difference associated with the main steam and feed water flows, as well as the hot and cold reheat streams, can be determined by measuring the pressure and temperature at the inlet and outlet of the superheater and reheater convection passes, respectively. Likewise, the mass flowrates through these passes can either be measured directly or inferred by appropriate mass and energy balances. The latter scenario may be necessary when tempering sprays or feedwater extractions occur during plant operations. Therein, $\dot{Q}_{\mathrm{steam}}$ is calculated as

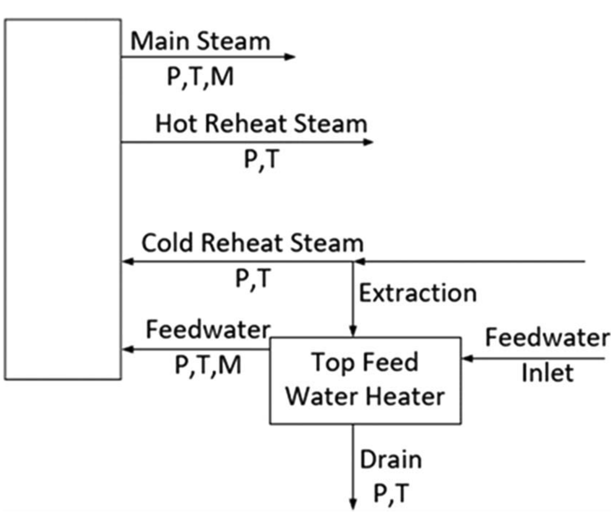

Fig. 1 System modeled by the output–loss method

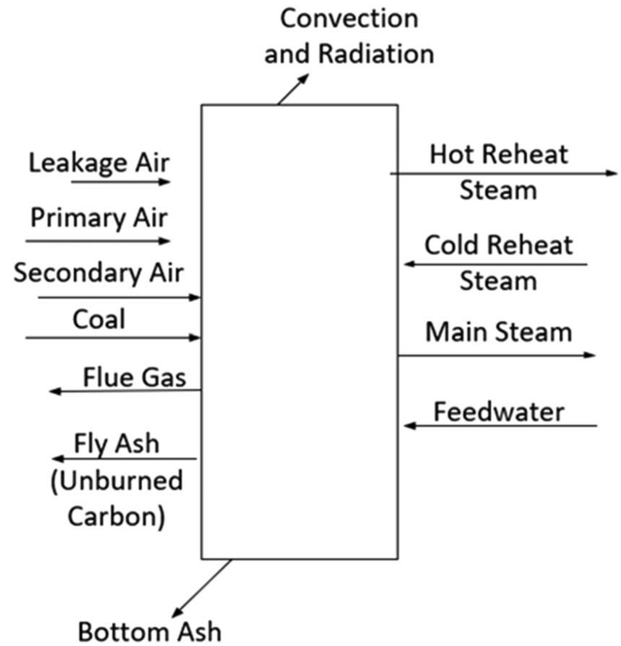

Fig. 2 Control volume boundary with associated inputs and losses

follows:

$$\dot{Q}_{\text{steam}} = [\dot{m}_{\text{MS}} \cdot h_{\text{MS}} - \dot{m}_{\text{FW}} \cdot h_{\text{FW}}] - [\dot{m}_{\text{HRH}} \cdot h_{\text{HRH}} - \dot{m}_{\text{CRH}} \cdot h_{\text{CRH}}] \tag{13}$$

Dry Flue Gas Loss. Consider the energy losses associated with the dry flue gases, i.e., the term $(\dot{E}_{\text{dry gases,out}} - \dot{E}_{\text{dry air,in}})$ in Eq. (12). The mass of dry air entering the boiler (per unit mass of as-fired coal) is given by

$$m_{\text{dry air,in}} = \frac{n_{O_2} \cdot \text{MW}_{O_2} + n_{N_2} \cdot \text{MW}_{N_2}}{\text{MW}_{\text{AF}}} \tag{14}$$

However, referring to Eq. (1), this can also be expressed as

$$m_{\text{dry air,in}} = \frac{\beta(1+E)[\text{MW}_{O_2} + 3.76 \cdot \text{MW}_{O_2}]}{\text{MW}_{\text{AF}}} \tag{15}$$

In general, the mass fraction x_i of any species in a mixture of gases is expressed in terms of the mole fraction y_i and its molecular weight MW_i, such that

$$x_i = \frac{y_i \cdot \text{MW}_i}{\sum y_i \cdot \text{MW}_i} \tag{16}$$

The denominator of Eq. (16) corresponds to the molecular weight of dry air, and may be expressed as follows:

$$\text{MW}_{\text{dry air}} = \left(\frac{1}{4.76}\right) \cdot \text{MW}_{O_2} + \left(\frac{3.76}{4.76}\right) \cdot \text{MW}_{N_2} \tag{17}$$

Hence, the mass fraction of O_2 in dry combustion air is given by

$$x_{O_2} = \frac{\left(\frac{1}{4.76}\right)\text{MW}_{O_2}}{\text{MW}_{\text{dry air}}} \tag{18}$$

Likewise, the mass fraction of N_2 in dry combustion air is

$$x_{N_2} = \frac{\left(\frac{3.76}{4.76}\right)\text{MW}_{N_2}}{\text{MW}_{\text{dry air}}} \tag{19}$$

Dry air is assumed to enter the boiler in three separate flow streams, i.e., boiler leakage, primary air, and secondary air. Each stream exhibits a different temperature, which is known from plant data. In that instance, the mass-specific enthalpy for both O_2 or N_2 is determined for each particular stream temperature using correlations presented in Ref. [1], and therein substituted into Eq. (20). This yields distinct values for the enthalpies of each air stream, i.e., h_{LA}, h_{PA}, and h_{SA}. The energy flowing into the control volume surrounding the boiler due to the three dry air streams is apportioned according to the percentage entering as leakage, and primary or secondary air. In that case, the dry air enthalpy entering is

$$h_{\text{dry air,in}} = x_{\text{LA}} \cdot h(T_{\text{LA}})_{\text{LA}} + x_{\text{PA}} \cdot h(T_{\text{PA}})_{\text{PA}} + x_{\text{SA}} \cdot h(T_{\text{SA}})_{\text{SA}} \tag{20}$$

The respective mass fractions in Eq. (20) denote the portion of dry air entering the control volumes with each stream. For example, it can readily be shown that the fraction of dry air attributable to leakage air can be expressed in terms of the oxygen molar ratio. Referring to Eq. (16)

$$x_{\text{LA}} = \frac{n_{O_2,\text{LA}}}{n_{O_2,\text{total}}} \tag{21}$$

Similar expressions can likewise be applied to evaluate the mass fractions of the primary and secondary air streams.

In this investigation, the dry flue gases are assumed to consist primarily of carbon dioxide, oxygen, and nitrogen, i.e., the mass and energy flow out of the boiler due to CO and SO_2 is deemed to be negligible. The mass of dry gas exiting from the control volume surrounding the boiler (expressed per unit mass of as-fired coal) is given by

$$m_{\text{dry gas,out}} = \frac{n_{CO_2} \cdot \text{MW}_{CO_2} + n_{O_2} \cdot \text{MW}_{O_2} + n_{N_2} \cdot \text{MW}_{N_2}}{\text{MW}_{\text{AF}}} \tag{22}$$

The mole fraction of CO_2 at the economizer exit is calculated based on the balanced reaction equation expressed by Eq. (1), such that

$$y_{CO_2} = \frac{n_{CO_2}}{n_{CO_2} \cdot \text{MW}_{CO_2} + n_{O_2} \cdot \text{MW}_{O_2} + n_{N_2} \cdot \text{MW}_{N_2}} \tag{23}$$

Likewise

$$y_{O_2} = \frac{n_{O_2}}{n_{CO_2} \cdot \text{MW}_{CO_2} + n_{O_2} \cdot \text{MW}_{O_2} + n_{N_2} \cdot \text{MW}_{N_2}} \tag{24}$$

And

$$y_{N_2} = \frac{n_{N_2}}{n_{CO_2} \cdot \text{MW}_{CO_2} + n_{O_2} \cdot \text{MW}_{O_2} + n_{N_2} \cdot \text{MW}_{N_2}} \tag{25}$$

Hence by reference to Eq. (16), the mass fraction of CO_2 in the dry gases exiting the economizer is given by

$$x_{CO_2} = \frac{y_{CO_2} \cdot \text{MW}_{CO_2}}{y_{CO_2} \cdot \text{MW}_{CO_2} + y_{O_2} \cdot \text{MW}_{O_2} + y_{N_2} \cdot \text{MW}_{N_2}} \tag{26}$$

Similarly,

$$x_{O_2} = \frac{y_{O_2} \cdot \text{MW}_{O_2}}{y_{CO_2} \cdot \text{MW}_{CO_2} + y_{O_2} \cdot \text{MW}_{O_2} + y_{N_2} \cdot \text{MW}_{N_2}} \tag{27}$$

Moreover,

$$x_{N_2} = \frac{y_{N_2} \cdot \text{MW}_{N_2}}{y_{CO_2} \cdot \text{MW}_{CO_2} + y_{O_2} \cdot \text{MW}_{O_2} + y_{N_2} \cdot \text{MW}_{N_2}} \tag{28}$$

By analogy to Eq. (20), enthalpy of the dry gases at the economizer exit is expressed as

$$h_{\text{dry gas,out}} = x_{CO_2} h(T_{\text{econ}})_{CO_2} + x_{O_2} h(T_{\text{econ}})_{O_2} + x_{N_2} h(T_{\text{econ}})_{N_2} \tag{29}$$

In every instance, the dry gases leave the control volume at the economizer exit temperature, which is known from plant data. Therein, the enthalpy of each dry gas is evaluated using correlations from in Ref. [1], and then substituted into Eq. (29). In that case the dry flue gas energy loss per unit mass flowrate of as-fired coal is calculated as follows:

$$\ell_{\text{dry flue gas}} = m_{\text{dry gas,out}} \cdot h_{\text{dry gas,out}} - m_{\text{dry air,in}} \cdot h_{\text{dry air,in}} \tag{30}$$

Moisture in Air Loss. Moisture in the combustion air is carried into the boiler control volume in three separate streams, i.e., leakage, primary air, and secondary air. The moisture in each stream assumes the same temperature as the respective airflow; that information is known from plant data. Hence, by analogy to Eq. (20), the enthalpy of the air moisture entering the control volume is given by

$$h_{\text{moisture,in}} = x_{\text{LA}} h(T_{\text{LA}})_{\text{vapor}} + x_{\text{PA}} h(T_{\text{PA}})_{\text{vapor}} + x_{\text{SA}} h(T_{\text{SA}})_{\text{vapor}} \tag{31}$$

The moisture leaves the boiler control volume as a vapor at the economizer exit temperature, which is likewise known from plant data. That implies

$$h_{\text{moisture,out}} = h(T_{\text{econ}})_{\text{vapor}} \tag{32}$$

The mass of dry air per unit mass of as-fired coal entering the boiler control volume is calculated by means of Eq. (15). The mass of water vapor in the combustion air can be expressed as

$$m_{\text{moisture,in}} = \frac{w \cdot \text{MW}_{\text{H}_2\text{O}}}{\text{MW}_{\text{O}_2} + 3.76\text{MW}_{\text{N}_2}} \tag{33}$$

In that case, the loss due to moisture in the combustion air per unit mass flowrate of as-fired coal is given by

$$\ell_{\text{air moisture}} = [m_{\text{dry air,in}} \cdot m_{\text{moisture,in}}] \cdot (h_{\text{moisture,out}} - h_{\text{moisture,in}}) \tag{34}$$

Fuel Moisture Loss. In this study, it is assumed that the moisture present in the fuel enters the boiler control volume as a saturated liquid at the primary air temperature. To account for the energy required to vaporize the fuel moisture, the heat of vaporization h_{fg} for water is determined from readily available correlations at the primary air temperature. The sensible enthalpy of the fuel moisture entering the control volume is likewise assessed at the primary air temperature, using correlations from Ref. [1]. Hence to characterize both sensible and latent energy effects, the fuel moisture at the boiler inlet is expressed as

$$h_{\text{moisture,in}} = h(T_{\text{PA}})_{\text{vapor}} + h_{\text{fg}}(T_{\text{PA}})_{\text{sat liq}} \tag{35}$$

Moreover, the fuel moisture leaves the control volume as a vapor at the economizer exit temperature, such that its enthalpy difference is expressed as follows, using correlations available in Ref. [1]:

$$h_{\text{moisture,out}} = h(T_{\text{econ}})_{\text{vapor}} \tag{36}$$

In this study, "FM" represents the percentage of moisture present in the coal; that quantity is known from an ultimate analysis. Hence, the loss per unit mass of coal due to the occurrence of moisture in the fuel is calculated as

$$\ell_{\text{fuel moisture}} = \left[\frac{\text{FM}}{100}\right](h_{\text{moisture,out}} - h_{\text{moisture,in}}) \tag{37}$$

Hydrogen Burning Loss. The hydrogen present in the coal chemically reacts with oxygen to form water vapor and thereby releases heat. However, that energy contribution is accounted for in the present analysis as comprising one aspect of the fuel's higher heating value. In this investigation, it is assumed that the moisture generated from fuel hydrogen combustion enters the boiler control volume as a saturated liquid at the primary air temperature. Therein as noted previously

$$h_{\text{moisture,in}} = h(T_{\text{PA}})_{\text{vapor}} + h_{\text{fg}}(T_{\text{PA}})_{\text{sat liq}} \tag{38}$$

That moisture leaves the control volume as a vapor at the economizer exit temperature, such that

$$h_{\text{moisture,out}} = h(T_{\text{econ}})_{\text{vapor}} \tag{39}$$

For the chemical reaction of hydrogen with oxygen, the mass of water produced per unit mass of hydrogen is expressed in terms of their molecular weight ratio (based on the balanced reaction equation). Thus per [1]

$$\frac{\text{MW}_{\text{H}_2\text{O}}}{\text{MW}_{\text{H}_2}} = \frac{18.02}{2.106} = 8.938 \tag{40}$$

Let "H" denote the percentage of hydrogen present in the coal as determined by means of an ultimate analysis. In that case, the loss per unit mass of coal due to hydrogen burning is given by

$$\ell_{\text{hydrogen burning}} = 8.938 \cdot \left[\frac{\text{H}}{100}\right](h_{\text{moisture,out}} - h_{\text{moisture,in}}) \tag{41}$$

Unburned Carbon Loss. When partial combustion occurs less energy than would be indicated by the fuel higher heating value would be released. That reduction of energy available to superheat the steam in the boiler is interpreted as a loss in this analysis. Incomplete combustion is accompanied by the presence of unburned carbon in the bottom ash. In that instance, per [1] the heating value of carbon in the ash equals 14,500 Btu/lbm. Based on an ultimate analysis, let "C" indicate the percentage of carbon occurring in the coal. Furthermore, let "x" represent the moles of unburned carbon (per mole of fuel carbon); refer to Eq. (1). Therefore, the loss per unit mass of coal due to unburned carbon is expressed as

$$\ell_{\text{unburned carbon}} = x \cdot 14{,}500 \cdot \left[\frac{\text{C}}{100}\right] \tag{42}$$

CO Formation Loss. Incomplete combustion is also revealed by the presence of carbon monoxide in the flue gases; this can occur even when an excess of air is supplied to the coal. As described in Ref. [1], the higher heating value of CO equals 4380 Btu/lbm. This corresponds to the energy released when carbon reacts with oxygen to form carbon monoxide. By contrast, the energy liberated by the chemical reaction of carbon with oxygen to form carbon dioxide (i.e., the higher heating value) equals 14,540 Btu/lbm. Hence, there is an attendant decrease in the energy that can be utilized to heat the steam when incomplete combustion occurs, and this is treated as a loss. Define the following quantity:

$$\Delta\text{HHV} = \text{HHV}_{\text{CO}_2} - \text{HHV}_{\text{CO}} = 10{,}160\ \text{Btu/lbm} \tag{43}$$

In that case, the equation for energy loss due to CO formation is given by

$$\ell_{\text{CO formation}} = \alpha \cdot \Delta\text{HHV} \cdot \left[\frac{\text{FM}}{100}\right] \tag{44}$$

Fly Ash and Bottom Ash Loss. The portion of the fuel comprised of ash is determined by an ultimate analysis of the coal. In this investigation that quantity is denoted as Ash_{pct}. The ash is assumed to enter the boiler control volume at the primary air temperature. However, the ash exits from the control volume in two different streams, i.e., as either fly ash or bottom ash. Generally, plant operators can estimate the percentage of the total ash that is in the fly ash stream, which is designated as $\text{FlyAsh}_{\text{pct}}$ in this study. In that case, the bottom ash percentage is inferred as follows:

$$\text{BottomAsh}_{\text{pct}} = 100 - \text{FlyAsh}_{\text{pct}} \tag{45}$$

The fly ash stream leaves the boiler at the flue gas temperature measured at the economizer exit. Hence, referring to a residue enthalpy correlation from Ref. [1], the fly ash energy loss can be expressed as

$$\ell_{\text{fly ash}} = \left(\frac{\text{Ash}_{\text{pcnt}}}{100}\right) \cdot \left(\frac{\text{FlyAsh}_{\text{pcnt}}}{100}\right) \cdot [h(T_{\text{econ}}) - h(T_{\text{PA}})] \tag{46}$$

The bottom ash leaves the boiler control volume at an elevated temperature which is monitored by plant operators and is herein designated as T_{BotAsh}. Hence based on a residue enthalpy correlation from Ref. [1], the bottom as energy loss is given by

$$\ell_{\text{bottom ash}} = \left(\frac{\text{Ash}_{\text{Pcnt}}}{100}\right) \cdot \left(\frac{\text{BotAsh}_{\text{Pcnt}}}{100}\right) \cdot [h(T_{\text{BotAsh}}) - h(T_{\text{PA}})] \tag{47}$$

The total energy loss attributed to ash is the sum of Eqs. (46) and (47).

Surface Radiation and Convection Loss. The surface radiation and convection loss calculated for use by the output–loss method utilizes the ABMA standard radiation loss chart, as shown in ASME PTC 4.1 [19]. In this study, a curve fit for this chart was developed to estimate the radiation loss at the maximum continuous output (denoted as RLMO). Define the heat input to the steam (i.e.,

$\dot{Q}_{steam}$), in units of MBtu/h as follows:

$$\text{WMCR} = \frac{\dot{Q}_{steam}}{10^6} \tag{48}$$

Similarly, designate XMCR as the maximum continuous rating of the boiler, in units of MBtu/h

$$\text{XMCR} = \frac{\text{MCR}}{10^6} \tag{49}$$

A least-squares curve fit to the radiation chart was performed to determine RLMO as a percentage of gross heat input (i.e., HHV), over several ranges of maximum continuous rating values. For example,

$$\text{RLMO} = \frac{2.600}{\text{XMCR}^{0.350}}; \quad \text{XMCR} \leq 1000\,\text{MBtu} \tag{50}$$

Likewise,

$$\text{RLMO} = \frac{1.161}{\text{XMCR}^{0.231}}, \quad 1000 < \text{XMCR} < 2000\,\text{MBtu} \tag{51}$$

And

$$\text{RLMO} = \frac{0.386}{\text{XMCR}^{0.086}}, \quad \text{XMCR} \geq 2000\,\text{MBtu} \tag{52}$$

Hence, once RLMO is calculated using the preceding correlations, an adjustment factor is applied to account for a plant operating at less than its maximum rating. In that case, the radiation loss expressed as a percentage of gross heat input is given by

$$Y = \text{RLMO} \cdot \left(\frac{\text{XMCR}}{\text{WMCR}}\right)^{.948} \tag{53}$$

Therein, the surface radiation and convection loss are approximated as

$$\ell_{radiation} = \left[\frac{Y}{100}\right] \cdot \text{HHV} \tag{54}$$

An alternate approach to evaluating the surface radiation and convection loss can likewise be found in Ref. [1]. However, that method requires knowledge of the projected surface area of the boiler. Such information may not be readily available to plant operators. In contrast, the boiler output ($\dot{Q}_{steam}$) is readily obtained, thereby motivating the utilization of the curve-fit approach herein described.

Calibration Algorithm. The calibration algorithm calculates calibration factors for the real-time method, including those for coal flowrate, and air preheater leakage, as well as for economizer exit concentrations of CO_2 and SO_2. Furthermore, it evaluates thermal losses and determines performance assessments such as boiler efficiency, heat rate, and modified F-factor at a given plant operating condition. As described in Ref. [17], a first-law energy balance performed on a control volume that conforms closely to the boiler can be expressed by means of Eq. (5). The quantities $\dot{Q}_{steam}$ and ℓ are determined from available plant data, using the methods described previously. In the present investigation, it is assumed that accurate coal heating value data are available. In that case, Eq. (5) can be solved explicitly the coal mass flowrate. This enables the calculation of a coal flow correction factor

$$\text{CoalFlCorFac} = \frac{\dot{m}_{coal}}{\dot{m}_{coal,plant}} \tag{55}$$

The correction factor is supplied by the calibration algorithm to be used in the real-time algorithm to calculate the actual coal flowrate; it is assumed to be a static variable. To a close approximation, such static data are not expected to change over time. The calibration algorithm likewise calculates two additional correction factors that are utilized to convert CEMS concentration data for SO_2 and CO_2 performed at the air preheater exit to their corresponding economizer outlet values. That information is subsequently supplied to the real-time algorithm, as required by the output–loss method. They are defined as follows:

$$\text{CO2CorFac} = \frac{y_{CO_2,stack}}{y_{CO_2,econ}} \tag{56}$$

And

$$\text{SO2CorFac} = \frac{y_{SO_2,stack}}{y_{SO_2,econ}} \tag{57}$$

The mole fractions for CO_2 and SO_2 in Eqs. (56) and (57) are evaluated based on the balanced reaction equation expressed by Eq. (1). These correction factors are likewise assumed to be static variables.

Real-Time Algorithm. The real-time algorithm is utilized to approximate the coal composition when a current ultimate analysis is unavailable. Therein the balanced chemical reaction equation is derived, thereby yielding the flue gas molar coefficients in Eq. (1) assessed at the economizer exit. Per [17], the real-time algorithm of the output–loss method presumes that the coal composition is unknown. This is a likely scenario if a coal ultimate analysis is outdated. In that case, there are eight unknowns in Eq. (1). These include the molar coefficients a, b, c, d, and f, as well as the parameters x, α, and E. However, if flue gas concentration data at the economizer exit are measured or can be inferred, there is sufficient information to perform four species mass balances. In addition, the molar ratios of oxygen and nitrogen to carbon for the coal, values of fuel moisture and ash percentages, and the percentage of total ash attributed to fly ash are assumed to be static variables. A preliminary calculation of unburned carbon x is performed by utilizing a static LOI value taken from the calibration algorithm. As shown in Ref. [17], the fraction of unburned carbon appearing in the total ash is given by

$$\text{UCTASH} = \left(\frac{\text{LOI}}{100}\right) \cdot \left(\frac{\text{FLYASH}}{100}\right) \tag{58}$$

The MAF composition of 100 pounds of coal is expressed as

$$\text{MAF} = 100(1 - A - M) \tag{59}$$

The number of carbon moles per unit weight of MAF coal is defined as follows:

$$\text{X2} = \left(\frac{\text{UCTASH}}{1 - \text{UCTASH}}\right) \cdot \left(\frac{\text{ASH}}{\text{MW}_c \cdot \text{MAF}}\right) \tag{60}$$

In addition, define the following fuel moisture parameter, which characterizes the number of moles of water in the fuel per mole of carbon:

$$\text{FM2} = \frac{\text{FM}}{\text{MAF} \cdot \text{MW}_{H_2O}} \tag{61}$$

Likewise, plant data for ambient pressure and relative humidity are used to evaluate the moisture in air. Measurements of CO_2 and SO_2 mole fractions performed at the air preheater exit are corrected back to their presumed values at the economizer exit based on Eqs. (56) and (57), thereby accounting for dilution caused by air preheater leakage. The real-time algorithm accesses plant data for such quantities as the primary, secondary, and leakage air temperatures, as well as the temperatures associated with the bottom ash and the flue gases at the economizer exit. This information is sufficient to determine the thermal losses per unit mass of coal ℓ, as described previously. Steam-side pressure, temperature, and mass flowrate data acquired from plant data are used to calculate the output $\dot{Q}_{\text{steam}}$. This enables the calculation of plant performance parameters as described by Eqs. (7)–(10).

The methodology employed in this study requires that real-time CEMS molar concentration data for CO and O_2 are attainable at the economizer exit. It is likewise necessary that similar CO_2 and SO_2 concentration data are available at the air preheater exit (i.e., entering the stack), or before any scrubber units preceding the stack. These measurements may be performed on either a dry or wet basis; this is described subsequently. Since the fuel composition is initially unknown, it is necessary to initiate the following iterative calculations. For the first iteration, it is assumed that the molecular weight of MAF coal corresponds to that of pure carbon

$$\text{MW}_{\text{MAF}} = 12 \tag{62}$$

Based on that guessed value, an initial estimate for the unburned carbon molar coefficient is given by

$$x = \text{X2} \cdot \text{MW}_{\text{MAF}} \tag{63}$$

Consider the sequence of required calculations, assuming that all CEMS data are measured on a wet basis. Referring to the balanced chemical reaction equation provided in Eq. (1), the number of moles of gaseous species present in products at the economizer exit (and therefore the denominator of any gas species mole fraction) is given by

$$D_{\text{wet}} = 1 + \frac{a}{2} + b + \frac{d}{2} + f + \beta(w + 3.76) + \beta E(w + 4.76) + \frac{\alpha}{2} \tag{64}$$

Therein, referring to Eqs. (1) and (64), based on the measured mole fraction of CO_2

$$\frac{1 - x - \alpha}{D_{\text{wet}}} = y_{\text{CO}_2,\text{econ}} \tag{65}$$

Similarly, since the CO concentration is measured at the economizer exit

$$\frac{\alpha}{D_{\text{wet}}} = y_{\text{CO},\text{econ}} \tag{66}$$

Adding Eqs. (65) and (66) yields

$$\frac{1 - x}{D_{\text{wet}}} = y_{\text{CO}_2,\text{econ}} + y_{\text{CO},\text{econ}} \tag{67}$$

Since x is known from Eq. (63), there is sufficient information to calculate D_{wet} by means of Eq. (67). Likewise, the molar coefficient α can be evaluated using Eq. (66). Furthermore, referring to Eqs. (1) and (64), the measured mole fraction of SO_2 at the economizer exit can be expressed as

$$\frac{b}{D_{\text{wet}}} = y_{\text{SO}_2,\text{econ}} \tag{68}$$

Thus consideration of Eq. (68) enables the calculation of the molar coefficient b. It is assumed that concentration data for O_2 are available at the economizer exit. Therein based on Eq. (1) the oxygen mole fraction is

$$\frac{\beta E + x + \frac{\alpha}{2}}{D_{\text{wet}}} = y_{\text{O}_2,\text{econ}} \tag{69}$$

Evaluation of Eq. (69) permits calculation of the quantity βE, as all other parameters in that equation are known. The fuel moisture molar coefficient f can be calculated as follows:

$$f = \text{FM2} \cdot \text{MW}_{\text{MAF}} \tag{70}$$

In this instance, the apparent molecular weight of moisture and ash-free coal (per unit mole of fuel carbon) is given by

$$\text{MW}_{\text{MAF}} = \text{MW}_{\text{C}} + a \cdot \text{MW}_{\text{H}} + b \cdot \text{MW}_{\text{S}} + c \cdot \text{MW}_{\text{O}} + d \cdot \text{MW}_{\text{N}} \tag{71}$$

Given that the ambient moisture molar coefficient w is known from plant data, this implies that Eq. (64) can be algebraically manipulated to solve for the remaining unknown molar coefficient a. Hence, at this point, values for the molar coefficients a, b, c, d, and f are known, based on the initial guess for the molecular weight of MAF coal. Using Eq. (2), it is noted that this likewise enables calculation of the molar coefficient β. Likewise, the excess air term E can be evaluated since the product βE is known. Therein, for the next iteration, it is necessary to reevaluate the molecular weight of MAF coal by means of Eq. (71), using the calculated values for a, b, c, and d, as determined previously. To complete the sequence of iterative calculations, the parameter $P1$ (which expresses the number of carbon moles per unit weight of MAF coal) is then evaluated as

$$P1 = \frac{\text{MAF}}{\text{MW}_{\text{MAF}}} \tag{72}$$

In that instance, the as-fired coal composition (expressed in terms of the weight percentage of each component per 100 pounds of coal) is updated, utilizing the following series of calculations:

$$\text{C (\%)} = P1 \cdot \text{MW}_{\text{C}} \tag{73}$$

$$\text{H (\%)} = P1 \cdot a \cdot \text{MW}_{\text{H}} \tag{74}$$

$$\text{S (\%)} = P1 \cdot b \cdot \text{MW}_{\text{S}} \tag{75}$$

$$\text{O (\%)} = P1 \cdot c \cdot \text{MW}_{\text{O}} \tag{76}$$

$$\text{N (\%)} = P1 \cdot d \cdot \text{MW}_{\text{N}} \tag{77}$$

Subsequently, an additional assessment of the number of moles of each species in the fuel is performed. The iterative calculations described by Eqs. (63)–(77) are continued until no further changes in fuel composition are observed, thereby yielding a close approximation to actual coal ultimate analysis.

The solution procedure to estimate the coal composition in real-time when gas concentrations are measured on a dry basis is very similar to that described previously for wet-based CEMS data. As before, the fuel molar coefficients c and d, as well as the quantities FM, ASH, LOI, and FLYASH, are supplied to the real-time algorithm as static variables. Likewise, the CO_2 and SO_2 correction factors are provided to the real-time algorithm by the calibration algorithm. The iterative calculations commence from a guessed value for the molecular weight of MAF coal. However, in this case, the number of moles of dry gaseous species at the economizer exit is expressed as

$$D_{\text{dry}} = 1 + b + \frac{d}{2} + 3.76\beta + 4.76E + \frac{\alpha}{2} \tag{78}$$

Therein, the iterative calculations as characterized by Eqs. (63)–(77) proceed as outlined previously, but with D_{wet} being replaced by D_{dry} in every instance. Convergence is attained when the calculated coal composition no longer changes, within a specified tolerance; this is typically achieved within five iterations.

Sensitivity Analysis

The calibration and real-time algorithms of the output–loss method rely on having accurate input data to provide reliable predictions of such quantities as boiler efficiency, heat rate, modified F-factor, etc. In general, the input variables may be subject to a range of both bias and precision errors, which eventually result in uncertainties associated with the calculated performance parameters. Hence, for this investigation sensitivity analyses were

Table 1 Static data [17]

BLRLK (%)	AIRCOAL kg/kg (lbm/lbm)	LOI (%)	FLYASH (%)	T_{ash} °C (°F)
1.5	2	0.5	88	1093 (2000)

Table 2 Ultimate analysis [17]

	Boiler load (MW)				
Components	VWO	400	350	280	200
C (%)	63.12	62.78	65.1	64.31	64.99
H (%)	4.24	4.14	4.21	4.24	4.41
S (%)	2.00	2.30	2.54	2.48	2.75
O (%)	7.06	7.66	6.86	7.01	7.33
N (%)	1.27	1.27	1.30	1.29	1.31
Fuel moisture (%)	13.07	13.7	11.99	12.15	10.99
ASH (%)	8.5	8.15	8.00	8.52	8.22
HHV kJ/kg (Btu/lbm)	26,195 (11,262)	26,186 (11,258)	26,809 (11,526)	26,677 (11,469)	27,184 (11,687)

conducted to determine the effects of varying key input data over a prescribed range to estimate how their respective uncertainties affect model calculations. This likewise served the purpose of predicting trends in coal-fired EGU performance as influenced by those particular variables. Due to the large number of input variables required by the output–loss model, simultaneous variations of all model inputs were deemed to be impractical. Two separate sensitivity analyses were performed. One consisted of varying the ultimate analysis of the coal, while the second consisted of varying dynamic parameters over a range of measurement uncertainties.

In Ref. [17], results from an output–loss model validation study were reported. For that investigation, representative data from a coal-fired EGU were utilized to calculate boiler efficiency and heat rate over a range of plant loads. The performance predictions were likewise compared to values that were obtained by testing that conformed with PTC 4 test procedures. Table 1 (taken from Ref. [17]) summarizes static data that were employed in that investigation. Table 2 contains ultimate analysis results and calorific data for each load case previously reported in Ref. [17]. The corresponding dynamic data shown in Table 3 were likewise provided in Ref. [17]; they represent measured values that were obtained during the period in which the coal samples used for the ultimate analysis were evaluated. It is anticipated that dynamic data will likely exhibit temporal variability. Referring to Ref. [17], it was noted that the oxygen and carbon monoxide measurements were performed at the economizer exit, whereas the carbon dioxide and sulfur dioxide measurements were performed at the air preheater exit. For the present sensitivity analysis, the 400 MW load data were selected as the baseline case. Therein, selected parameters that were expected to significantly impact output–loss model calculations were systematically adjusted from their baseline values to assess the resulting effects on predictions obtained using the calibration and real-time algorithms.

It was shown in Ref. [17] that the ability of the calibration and real-time performance algorithms to accurately assess instantaneous boiler efficiency and plant heat rate was enhanced if the most current coal ultimate and calorific analysis was utilized. In many applications, Dulong's formula is used to approximate coal's higher heating value as a function of coal composition. Hence, referring to Ref. [20], Dulong's equation is given by

$$\mathrm{HHV} = 14{,}544 \cdot \mathrm{C} + 62{,}028\left[\mathrm{H} - \frac{\mathrm{O}}{8}\right] + 4{,}050 \cdot \mathrm{S}; \quad \sim \ \mathrm{Btu/lbm} \tag{79}$$

In Eq. (79), for a given coal sample, "C" denotes the weight fraction of carbon in coal, "H" is the weight fraction of molecular hydrogen, "O" refers to the weight fraction of molecular oxygen, and "S" is the sulfur weight fraction. In Table 4, coal higher heating values acquired from a laboratory ultimate analysis are compared to those obtained using the Dulong equation, for the cases originally considered in Ref. [17]. In every instance the results obtained by both approaches differ by no more than 1.4%, implying that Dulong's formula provided adequate predictions.

Table 3 Dynamic measured data [17]

	Boiler load (MW)				
Variable	VWO	400	350	280	200
T_{amb} °C (°F)	31.8 (89.2)	28.6 (83.5)	28.2 (82.8)	28.5 (83.3)	26.8 (80.2)
Relative humidity (%)	79.7	71.9	74.2	76.4	75.8
T_{PA} (°F)	76.7 (170)	76.7 (170)	76.7 (170)	76.7 (170)	76.7 (170)
T_{SA} (°F)	326.6 (619.8)	311.2 (592.2)	301.5 (574.7)	298.1 (568.6)	288.8 (551.8)
T_{LA} (°F)	384.9 (724.9)	360.7 (681.3)	344.8 (652.6)	340.4 (644.7)	325.1 (617.2)
$\dot{Q}_{steam}$ kW (Btu/h)	1.08×10^6 (3.70×10^9)	0.92×10^6 (3.15×10^9)	0.81×10^6 (2.78×10^9)	0.66×10^6 (2.25×10^9)	0.49×10^6 (1.66×10^9)
$\dot{m}_{coal}$ kg/h (ton/h)	1.66×10^5 (182.8)	1.41×10^5 (155.0)	1.21×10^5 (133.6)	0.98×10^5 (108.4)	0.71×10^5 (78.6)
y_{O_2} (%)	3.33	2.98	3.97	3.52	4.15
y_{CO} (ppm)	13.7	154.7	151.3	137.5	9.1
y_{CO_2} (%)	13.8	14.1	14.0	13.8	12.8
y_{SO_2} (ppm)	2395.9	2417.1	2396.8	2400.0	2400.0

Table 4 Dulong equation HHV analysis

	Load (MW)				
HHV (kJ/kg) (Btu/Lbm)	VWO	400	350	280	200
Ultimate	26,195 (11,262)	26,186 (11,258)	26,809 (11,526)	26,677 (11,469)	27,184 (11,687)
Dulong	26,465 (11,378)	26,126 (11,232)	27,182 (11,686)	26,923 (11,575)	27,368 (11,766)
% Difference	+1.03	−0.23	+1.39	+0.92	+0.68

Table 5 Ultimate analysis effects on boiler performance calculated using the calibration algorithm

Parameter	Variation	HHV Dulong kJ/kg (Btu/lbm)	CO2 Cor. Fac	SO2 Cor. Fac	Coal Fl Cor. Fac	AP Leak %	$\dot{m}_{coal}$ kg/h (ton/h)	η_b (%)	HR_{Gross} (Btu/kW-h)	HR_{Net} (Btu/kW-h)
C	−10%	24,804 (10,664)	0.920	0.883	1.079	7.7	1.52×10^5 (167.3)	88.23	8928	9724
	Nominal	26,186 (11,258)	0.888	1.107	1.008	11.3	1.42×10^5 (156.2)	89.50	8801	9586
	10%	27,447 (11,800)	0.862	1.423	0.950	14.4	1.34×10^5 (147.2)	90.60	8694	9469
H	−10%	25,616 (11,013)	0.875	1.091	1.029	12.8	1.45×10^5 (159.5)	89.63	8789	9572
	Nominal	26,186 (11,258)	0.888	1.107	1.008	11.3	1.42×10^5 (156.2)	89.50	8801	9586
	10%	26,635 (11,451)	0.901	1.123	0.993	9.8	1.40×10^5 (153.9)	89.33	8817	9604
S	−10%	26,165 (11,249)	0.887	1.232	1.009	11.4	1.42×10^5 (156.4)	89.48	8803	9588
	Nominal	26,186 (11,258)	0.888	1.107	1.008	11.3	1.42×10^5 (156.2)	89.50	8801	9586
	10%	26,086 (11,215)	0.889	1.006	1.012	11.2	1.42×10^5 (156.9)	89.47	8804	9589
O	−10%	26,493 (11,390)	0.891	1.111	0.996	10.9	1.40×10^5 (154.3)	89.56	8795	9579
	Nominal	26,186 (11,258)	0.888	1.107	1.008	11.3	1.42×10^5 (156.2)	89.50	8801	9586
	10%	25,760 (11,075)	0.885	1.103	1.026	11.6	1.44×10^5 (159.0)	89.39	8812	9598
N	−10%	26,160 (11,247)	0.888	1.107	1.009	11.3	1.42×10^5 (156.4)	89.48	8803	9588
	Nominal	26,186 (11,258)	0.888	1.107	1.008	11.3	1.42×10^5 (156.2)	89.50	8801	9586
	10%	26,093 (11,218)	0.888	1.108	1.012	11.3	1.42×10^5 (156.8)	89.47	8804	9589
FM	−10%	26,540 (11,410)	0.888	1.107	0.992	11.3	1.40×10^5 (153.8)	89.68	8783	9567
	Nominal	26,186 (11,258)	0.888	1.107	1.008	11.3	1.42×10^5 (156.2)	89.50	8801	9586
	10%	25,712 (11,054)	0.888	1.107	1.029	11.3	1.45×10^5 (159.5)	89.27	8824	9611
ASH	−10%	26,358 (11,332)	0.888	1.107	1.001	11.3	1.41×10^5 (155.2)	89.51	8800	9585
	Nominal	26,186 (11,258)	0.888	1.107	1.008	11.3	1.42×10^5 (156.2)	89.50	8801	9586
	10%	25,895 (11,133)	0.888	1.107	1.020	11.3	1.43×10^5 (158.1)	89.44	8807	9592

This comparison was performed to facilitate subsequent parametric studies, where the coal composition was varied over a range, in order to investigate the influence of coal composition uncertainty.

For the sensitivity study considered in this investigation, it was assumed that if the weight fraction of a particular species was measured inaccurately (due to presumed bias or precision errors) the weight fractions of the remaining species would likewise be affected in a proportional manner. The sum of the weight fractions for a coal sample must equal 100%. This implies that if the weight fraction on a percent basis of a particular coal component x_i is measured incorrectly by an amount $\pm\delta x_i$, the weight fractions of the other species must change by the following correction factor:

$$\mathrm{cf} = 1 - \frac{\pm x_i}{100 - x_i} \tag{80}$$

For example, if the measured weight fraction of a particular species is too high, then x_i is positive. In that case, by Eq. (80) it is assumed that the other component weight fractions will decrease by their nominal value, multiplied by the correction factor. Conversely, if the weight fraction of a certain component has too low of a measured value, then x_i is negative. Therein, Eq. (80) implies that the weight fractions of the other species will increase in a similar manner.

Table 5 summarizes the effects of uncertainties associated with the ultimate analysis of the coal sample for the 400 MW baseline case, considering prescribed variations associated with carbon, hydrogen, sulfur, oxygen, nitrogen, moisture, and ash composition of the fuel. In each instance, for ±10% uncertainties associated with the weight fraction of a particular coal constituent, the remaining weight fractions were corrected accordingly using Eq. (80). In every instance the static data were acquired from Table 1, and the dynamic data were taken from Table 3 (for the 400 MW baseline case). The higher heating value for the baseline case was taken from Table 2; it was measured by methods that conformed to PTC 4; refer to Ref. [21]. However, when the fuel composition

Table 6 Ultimate analysis effects on boiler performance calculated using the real-time algorithm

Parameter	Variation	HHV Dulong (Btu/lbm)	CO2 Cor. Fac	SO2 Cor. Fac	Coal Flow Cor. Fac	AP Leak %	$\dot{m}_{coal}$ kg/h (ton/h)	η_b (%)	HR_{Gross} (Btu/kW-h)	HR_{Net} (Btu/kW-h)
C	−10%	24,804 (10,664)	0.888	1.107	1.008	11.3	1.42×10^5 (156.2)	89.51	8799	9584
	Nominal	26,186 (11,258)						89.50	8801	9586
	10%	27,447 (11,800)						89.48	8802	9587
H	−10%	25,616 (11,013)						89.50	8800	9585
	Nominal	26,186 (11,258)						89.50	8801	9586
	10%	26,635 (11,451)						89.50	8801	9586
S	−10%	26,165 (11,249)						89.50	8801	9586
	Nominal	26,186 (11,258)						89.50	8801	9586
	10%	26,086 (11,215)						89.50	8801	9586
O	−10%	26,493 (11,390)						89.52	8799	9584
	Nominal	26,186 (11,258)						89.50	8801	9586
	10%	25,760 (11,075)						89.48	8803	9588
N	−10%	26,160 (11,247)						89.49	8802	9587
	Nominal	26,186 (11,258)						89.50	8801	9586
	10%	26,093 (11,218)						89.51	8800	9585
FM	−10%	26,540 (11,410)						89.54	8797	9582
	Nominal	26,186 (11,258)						89.50	8801	9586
	10%	25,712 (11,054)						89.46	8804	9589
ASH	−10%	26,358 (11,332)						89.45	8806	9591
	Nominal	26,186 (11,258)						89.50	8801	9586
	10%	25,895 (11,133)						89.55	8796	9580

Table 7 Dynamic variables effects on boiler performance calculated using the calibration algorithm

Parameter	Variation	CO2 Cor. Fac	SO2 Cor. Fac	Coal Flow Cor. Fac	AP Leakage (%)	η_b (%)	HR_{Gross} (Btu/kW-h)	HR_{Net} (Btu/kW-h)
T_{amb}	−10%	0.888	1.107	1.008	11.3	89.52	8799	9583
	Nominal	0.888	1.107	1.008	11.3	89.50	8801	9586
	10%	0.888	1.107	1.008	11.3	89.47	8804	9589
RH	−10%	0.888	1.107	1.008	11.3	89.51	8800	9585
	Nominal	0.888	1.107	1.008	11.3	89.50	8801	9586
	10%	0.888	1.107	1.008	11.3	89.49	8802	9587
T_{PA}	−10%	0.888	1.107	1.010	11.3	89.34	8817	9603
	Nominal	0.888	1.107	1.008	11.3	89.50	8801	9586
	10%	0.888	1.107	1.006	11.3	89.66	8785	9568
T_{SA}	−10%	0.888	1.107	1.019	11.3	88.49	8901	9695
	Nominal	0.888	1.107	1.008	11.3	89.50	8801	9586
	10%	0.888	1.107	0.997	11.3	90.52	8702	9478
y_{O_2}	−10%	0.874	1.089	1.007	12.9	89.53	8797	9582
	Nominal	0.888	1.107	1.008	11.3	89.50	8801	9586
	10%	0.903	1.126	1.008	9.6	89.46	8805	9590
y_{CO}	−10%	0.888	1.107	1.008	11.3	89.51	8800	9585
	Nominal	0.888	1.107	1.008	11.3	89.50	8801	9586
	10%	0.888	1.107	1.008	11.3	89.49	8801	9586
y_{CO_2}	−10%	0.799	1.107	1.008	22.5	89.50	8801	9586
	Nominal	0.888	1.107	1.008	11.3	89.50	8801	9586
	10%	0.977	1.107	1.008	2.1	89.50	8,801	9586
y_{SO_2}	−10%	0.888	0.997	1.008	11.3	89.50	8801	9586
	Nominal	0.888	1.107	1.008	11.3	89.50	8801	9586
	10%	0.888	1.218	1.008	11.3	89.50	8801	9586
$\dot{Q}_{Steam}$	−10%	0.888	1.107	0.907	11.3	89.48	7923	8629
	Nominal	0.888	1.107	1.008	11.3	89.50	8801	9586
	10%	0.888	1.107	1.108	11.3	89.52	9679	10,542
$\dot{m}_{coal}$	−10%	0.888	1.107	1.120	11.3	89.50	8801	9586
	Nominal	0.888	1.107	1.008	11.3	89.50	8801	9586
	10%	0.888	1.107	0.916	11.3	89.50	8801	9586

Table 8 Dynamic variables effects on boiler performance calculated using the real-time algorithm

Parameter	Variation	CO2 Cor. Fac	SO2 Cor. Fac	Coal Flow Cor. Fac	AP Leakage (%)	η_b (%)	HR_{Gross} (Btu/kW-h)	HR_{Net} (Btu/kW-h)
T_{amb}	−10%	0.888	1.107	0.996	11.3	89.52	8799	9584
	Nominal					89.50	8801	9586
	10%					89.47	8804	9589
RH	−10%					89.51	8800	9585
	Nominal					89.50	8801	9586
	10%					89.49	8802	9587
T_{PA}	−10%					89.35	8815	9601
	Nominal					89.50	8801	9586
	10%					89.65	8787	9570
T_{SA}	−10%					88.60	8890	9682
	Nominal					89.50	8801	9586
	10%					90.42	8711	9488
y_{O_2}	−10%					89.18	8833	9620
	Nominal					89.50	8801	9586
	10%					89.83	8769	9551
y_{CO}	−10%					89.50	8801	9585
	Nominal					89.50	8801	9586
	10%					89.50	8801	9586
y_{CO_2}	−10%					87.30	9022	9827
	Nominal					89.50	8801	9586
	10%					91.55	8604	9372
y_{SO_2}	−10%					89.46	8804	9590
	Nominal					89.50	8801	9586
	10%					89.54	8797	9582
$\dot{Q}_{Steam}$	−10%					88.44	8015	8730
	Nominal					89.50	8801	9586
	10%					90.38	9587	10,442
$\dot{m}_{coal}$	−10%					90.45	8709	9485
	Nominal					89.50	8801	9586
	10%					88.57	8893	9686

was adjusted for the sensitivity analysis, the higher heating values were re-calculated using Dulong's equation, i.e., Eq. (79). Therein, the *calibration algorithm* was utilized to assess the influence of uncertainties associated with fuel composition on several key calculated performance parameters. For each case, the CO_2 and SO_2 correction factors were calculated by means of Eqs. (56) and (57), respectively. Likewise, the coal mass flow correction factor was determined using Eq. (55). The effects of coal composition uncertainty on the predicted air preheater leakage are also included in Table 5. Based on these calculated correction factors, for each presumed coal composition the calibration algorithm evaluated the corrected coal mass flowrate per Eq. (55). Likewise, the boiler efficiency was calculated using Eq. (7), and the gross heat rate and net heat rate were evaluated by means of Eqs. (9) and (10), respectively.

Table 6 likewise characterizes the influence of uncertainties associated with the coal sample ultimate analysis for the 400 MW baseline case. However, in these instances, the *real-time algorithm* was utilized to predict such quantities as boiler efficiency and heat rate. As before, the static data were taken from Table 1, and the dynamic data were based on values from Table 3. However, for each coal composition, the real-time algorithm employed the CO_2 and SO_2 correction factors, the coal mass flowrate correction factor, and the air preheater leakage value, as calculated previously by the calibration algorithm specifically for the baseline case.

Table 7 summarizes the influence of uncertainties associated with the dynamic data employed in the 400 MW baseline case, considering a $\pm 10\%$ range of measurement errors for each parameter. These results for such performance parameters as boiler efficiency and heat rate were calculated using the *calibration algorithm*. In every instance, the dynamic data nominal values were taken from Table 2 for the 400 MW baseline case. Likewise, the static data were based on values provided in Table 1, whereas the coal composition and fuel higher heating value conformed to those listed in Table 3 for the 400 MW case. By contrast, Table 8 recapitulates boiler efficiency and heat rates calculated by the *real-time algorithm,* where CO_2 and SO_2 correction factors, the coal mass flowrate correction factor, and the air preheater leakage value previously determined by the calibration algorithm were utilized, as calculated for the 400 MW baseline case.

Conclusions

For an EGR unit with a boiler efficiency of approximately 90%, the output–loss method described in this investigation exhibited significant sensitivity associated with measured values of $\dot{Q}_{\mathrm{Steam}}$. This was expected since the steam heat transfer rate was the dominant term in the overall boiler energy balance. Other input parameters generally yielded a much lower influence on calculated heat rate. Referring to Table 4, the Dulong equation, i.e., Eq. (79), predicted the coal higher heating values for the fuels studies in Ref. [17] with an accuracy of $\pm 1.4\%$, thus bolstering confidence in the parametric study as it related to fuel composition uncertainty. Per Table 5, uncertainties in fuel moisture and ash content on the order of $\pm 10\%$ apparently had minor impacts on the CO_2, SO_2, coal flow, and air preheater correction factors calculated by calibration algorithm. These observations likewise applied to ultimate analysis uncertainties of $\pm 10\%$ associated with sulfur, oxygen, and nitrogen weight percentages obtained from an ultimate analysis, i.e., the correction factors were insensitive to those species weight fractions. Hence such measurement uncertainties had negligible impacts on calculated EGU performance parameters such as coal flowrate, boiler efficiency, and gross and net heat rates. Ultimate analysis measurement uncertainties of $\pm 10\%$ for the carbon content or hydrogen content of fuel were more significant than for the other ultimate analysis measurement uncertainties. For example a $\pm 10\%$ uncertainty associated with coal carbon content was reflected in corresponding coal flowrate miscalculations of $\pm 7.1\%$ and heat rate calculation errors on the order of $\pm 1.5\%$ from the calibration algorithm. Similarly, hydrogen content ultimate analysis uncertainties of $\pm 10\%$ yielded calibration algorithm coal flowrate inaccuracies of $\pm 2.1\%$, but heat rate prediction errors were limited to $\pm 0.1\%$. In contrast, referring to Table 6, when correction factors taken from the calibration algorithm were used as input to the real-time algorithm, uncertainties of $\pm 10\%$ for each fuel component weight fraction yielded insignificant real-time prediction variations for the principal EGU performance parameters. It is concluded once the coal composition has been inferred by means of the iterative procedure, the boiler efficiency and heat rate calculations in the real-time algorithm are insensitive to fuel composition uncertainties of $\pm 10\%$, provided that accurate correction factors are available as input. It should not be inferred that a $\pm 10\%$ measurement uncertainty for the input parameters alluded to in Tables 5–8 would represent typical values. For example, the Clean Air Act and its amendments [22] mandate much tighter restrictions on the accuracy of flue gas concentration measurements needed to monitor emissions, to verify that air quality standards have been met.

As indicated in Table 7, measurement errors on the order of $\pm 10\%$ for the various dynamic variables had inconsequential effects of the calibration factors determined by the calibration algorithm. The notable exceptions to that observation pertained to measurement errors associated with the steam heat transfer rate and the coal mass flowrate. For example, measurement errors of $\pm 10\%$ for $\dot{Q}_{\mathrm{Steam}}$ yielded coal flow correction factors that varied over a $\pm 10\%$ range. Similarly, coal flowrate measurement uncertainties of $\pm 10\%$ yielded coal flow correction factors that exhibited approximately $\pm 10\%$ magnitudes. There was no discernable impact of coal mass flowrates error on heat rate predictions from the calibration algorithm, due to the fact that the losses were calculated on a per unit mass of coal basis. Per Table 8, when correction factors acquired from the calibration algorithm were used as input to the real-time algorithm, uncertainties of $\pm 10\%$ for each dynamic variable typically exhibited minimal impacts on the main EGU performance parameter predictions such as boiler efficiency, and gross and net heat rates. However, this was emphatically not the case for measurement uncertainties attributable to the steam and coal mass flowrates. For example, a $\pm 10\%$ measurement error for $\dot{Q}_{\mathrm{Steam}}$ resulted in heat rate calculation errors of $\pm 8.6\%$. Boiler efficiencies of approximately 90% implied that the majority of the heat released by coal combustion was conveyed to the steam, and was not therein attributable to losses. Similarly, a $\pm 10\%$ uncertainty associated with $\dot{m}_{\mathrm{coal}}$ yielded heat rate calculation errors of $\pm 1.1\%$. Hence it is concluded that for optimal accuracy of the output–loss method it is imperative that steam and coal mass flowrates must be measured as accurately as possible. As noted in Ref. [17], the most recently available ultimate analysis data should be provided to the real-time algorithm, to ensure its best accuracy.

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Conflict of Interest

There are no conflicts of interest. This article does not include research in which human participants were involved. Informed consent not applicable. This article does not include any research in which animal participants were involved.

Data Availability Statement

The authors attest that all data for this study are included in the paper.

Nomenclature

a = moles of hydrogen per mole of fuel carbon mole/mole
c = moles of oxygen per mole of fuel carbon mole/mole
d = moles of nitrogen per mole of fuel carbon mole/mole
f = moles of H_2O per mole of fuel carbon mole/mole
h = enthalpy kW/kg (Btu/lbm)
ℓ = thermal losses per unit mass of coal kW/kg (Btu/lbm)
m = mass kg (lbm)
$\dot{m}$ = mass flowrate kg/h (lbm/h)
n = moles mole
w = moles of H_2O per mole of O_2 mole/mole
x = mass fraction kg/kg (lbm/lbm)
y = mole fraction mole/mole
A = ash mass fraction kg/kg (lbm/lbm)
B = moles of sulfur per mole of fuel carbon mole/mole
D = denominator of any gas species mole fraction mole
E = moles of excess O_2 per mole of fuel carbon mole/mole
$\dot{E}$ = energy transfer rate kW (Btu/h)
M = moisture mass fraction kg/kg (lbm/lbm)
$\dot{Q}$ = heat transfer rate kW (Btu/h)
T = temperature °C (°F)
X = moles of unburned carbon per mole of fuel carbon kg/kg (lbm/lbm)
Y = radiation loss as a percentage of gross heat input
cf = correction factor for coal sensitivity analysis dim.
ASH = ultimate analysis ash mass %
Bottom Ash = bottom ash
CO2CorFac = CO_2 correction factor mole/mole
CoalFlCorFac = coal flow correction factor kg/kg (lbm/lbm)
FLYASH = fraction of total ash appearing as fly ash kg/kg (lbm/lbm)
FM = ultimate analysis moisture mass %
FM2 = moles of H_2O per mole of fuel carbon mole/mole
HHV = higher heating value kW/kg (Btu/lbm)
HR = heat rate Btu/kW-h
KW = power generated kW
Lo = thermal losses kW (Btu/h)
LOI = loss on ignition %
MAF = moisture ash free kg/kg (lbm/lbm)
MW = molecular weight kg/mole (lbm/mole)
P1 = carbon moles per unit weight of MAF coal mole/kg (mole/lbm)
RLMO = radiation loss at max output %HHV
SO2CorFac = SO_2 correction factor mole/mole
SS = station service kW
UCTASH = fraction of unburned carbon in total ash kg/kg (lbm/lbm)
WMCR = heat input MW (MBtu/h)
X2 = moles of carbon per unit weight of MAF coal kg/mole (lbm/mole)
XMCR = maximum continuous rating of the boiler MW (MBtu/h)

Greek Symbols

α = moles of CO per mole of fuel carbon mole/mole
β = stoichiometric combustion air molar coefficient mole/mole
β = change
η_B = boiler efficiency %

Subscripts

air = air
ash = ash
coal = coal
dry = dry basis
econ = economizer exit
flue gas = flue gas
formation = formation
in = inlet
moisture = moisture
total = total
out = outlet
unburned carbon = unburned carbon
AF = as-fired
Botash = bottom ash stream
Cycle = cycle
CRH = cold reheat stream
Flyash = fly ash
Fuel Moisture = fuel moisture
FW = feedwater
Gases = gas
Gross = gross
Hydrogen Burning = hydrogen burning
HRH = hot reheat
LA = leakage air
MAF = moisture ash free
MS = main steam
Net = net
PA = primary air
Pct = percent
Plant = plant instrumentation
SA = secondary air
Sat liq = saturated liquid
Stack = air preheater exit
Steam = steam
Vapor = vapor
Wet = wet basis

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