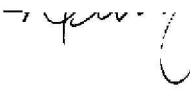# AN ABSTRACT OF THE THESIS OF

Charles Craig Haluzak for the degree of Master of Science in Mechanical Engineering, presented May 4, 1989.

Title : Experimental Combustion Analysis and Development of Representative Fuel Specifications for Selected Wood and Refuse Derived Fuel Pellets from the Pacific Northwest.

Abstract Approved : _____
D.J. Bushnell

An experimental biomass combustion facility has been built and established at Oregon State University. The furnace, or Biomass Combustion Unit (BCU), uses an auger-type fuel feed system, grate-type fuel support with under and over fire air supply.

Fourteen pellet species from five States - Alaska, Washington, Oregon, Idaho, and Montana were analyzed for a large number of physical and chemical variables. These variables included higher heating value, moisture content, ultimate analysis, etc. Three separate combustion experiments were conducted using nine of the available fourteen wood pellets.

The overall objective was to simply burn wood biomass pellets under "reasonable" operating conditions and report the relative combustion performance of each fuel.

More specifically, the three combustion experiments coupled with the pellet analysis data supported the following conclusions :

1.   It was possible to construct a simple mathematical model describing the simultaneous effects of under fire air and over fire air on pellet efficiency performance. The model was used to predict the optimal firing conditions based on thermal efficiency. It is hypothesized that the model is broadly (but approximately) applicable to all fourteen pellet species examined in this report.

2.   Tests indicate that all nine of the relatively diverse wood pellet fuels behave similarly under similar operating conditions.

3.   Carbon monoxide and oxides of nitrogen never reached mean values of over 215 parts per million for all experiments.

4.   Fuel-bound salt was found to cause relatively large particulate fly ash and opacity readings and resulted in the only slag formation.

5.   Increasing under fire air temperature by 230 deg.F on average yielded a statistically significant (but small) increase in mean combustion gas temperature. There was not a statistically significant effect on combustion efficiency as measured by carbon dioxide concentration in the exhaust gases.

Experimental Combustion Analysis and
Development of Representative Fuel Specifications
for Selected Wood and Refuse Derived Fuel Pellets
from the Pacific Northwest

by

Charles Craig Haluzak

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Redacted for Privacy

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Dean of Graduate School

Date thesis is presented_____May 4, 1989_____

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INTRODUCTION

It is general knowledge that man has been using wood and other forms of organic flammable material to produce heat energy since before recorded history. Despite the length of time man has had to study the physical and chemical nature of this organic (biomass)* fuel, there are considerable gaps in the pure and applied science of solid biomass fuel combustion. There are several reasons for this void of information, a few of which will be given below. This report attempts to bridge some gaps in the areas of applied or technological understanding and in the pure science of biomass fuel combustion.

* : Biomass — For this report "biomass" is defined as any organic (carbon based) fuel , including wood, agricultural residue, Municipal Solid Waste (MSW), and Refuse Derived Fuel ("derived" from MSW by mechanical means such as screens and air classifiers). It does not include fossil fuels such as, coal, oil, and natural gas. The properties of coal are used many times in comparisons with biomass in this report because coal is the most thoroughly understood solid fuel at present.

One reason for the lack of knowledge about biomass combustion is the complexity of solid combustion reactions in general. The "complete" analytical model of a sustained biomass combustion reaction requires the solution of many simultaneous equations from the diverse fields of conduction, radiation, convection, thermodynamics, and chemical reaction kinetics. Another problem is that, even if we could solve this immense set of equations, the solution would only be valid for the specified boundary and initial conditions. Unfortunately, there are an infinite number of sets of these conditions, so, researchers up to now have made their own decisions about which cases are most important or yield the most clarifying information. This is very much like the field of convection heat transfer where empirical correlations must be determined when pure theory is not adequate. Fortunately, the introduction of the digital computer is helping this endeavor.

Another reason for the lack of knowledge is that by the time engineers and scientists became adept enough to study the complex phenomena of solid combustion in general, the primary fuels of interest were coal, gas, and oil (fossil fuels), not wood or municipal solid waste. This has begun to change since the advent of the idea that non-renewable energy sources such as coal, oil, and nuclear fission, are not necessarily the best ways to deal with global energy needs in the future ; for economic, security, political, and

environmental reasons. It has become apparent that large, centralized, power producing facilities may not be as efficient at meeting consumer demands as smaller more regionally designed power systems. This is particularly true in certain cases where inexpensive biomass fuel is available in large quantities. It is also true that these same communities or regions are having difficulty disposing of their combustible waste streams, i.e. the communities must PAY to dispose of this "fuel source". This situation produces a consummate match of raw material to energy demand in the above scenario. This match is not perfect, it contains pitfalls such as the possibility of producing acid-rain , poor air quality in general, and aiding the chemical degradation of our atmosphere due to heat, carbon dioxide, and carbon monoxide emissions. These pitfalls however, just increase the motivation for more advanced solid biomass fuels study. It is anticipated that the following report will be both a useful assemblage of "old" information and also a step forward in biomass fuels research.

The final reason for the current status of biomass fuel combustion research is rooted in politics and business. A fair amount of the current research in biomass fuels is centered on the development of fuel standards or criteria. The concept behind these criteria is the same as the reason that safety codes or ingredient labeling arose in our current law. It is for the protection of the consumer and

for the consumer's general knowledge so that he can best
utilize the available resource. These standards are not
always welcomed by the manufacturer or retailer of any such
"labeled" product. There are a number of good reasons for
this. One reason is that it _costs_ the manufacturer both for
research and packaging. Second, it has the potential to
elucidate shortcomings in the product that would otherwise
go unnoticed-(at least initially !). Third, it is
difficult enough to get scientists who support industry-wide
criteria development to _agree_ on the variables and methods
of testing, regardless of those who _oppose_ standardization.
This division in the biomass fuels industry has the
consequence of limiting the amount of research dollars that
public institutions such as Oregon State University receive.
This is true because government policy is greatly influenced
by industry lobby. If government does not sense a unified
interest in biomass fuels combustion research it will not
respond by allocation of funds. These funds are needed to
continue basic research that industry either cannot afford
or does not desire to carry out, but may be important to the
security of our energy future.

It is for the above reasons that this endeavor into
biomass fuels combustion has occurred. The thoroughness of
testing and the quantity and quality of information
presented herein should help make this document a good
reference for furnace and boiler design engineers and

applied combustion scientists. It is also a good general
reference on the physical and chemical characteristics of
wood-based pellet fuels in the Five State Pacific Northwest
Region[b]. It is anticipated that some questions of interest
will be answered by this research and more importantly we
may learn to ask the right questions.

[b] : The Five State Northwest Region includes : Alaska,
Montana, Idaho, Oregon, and Washington. Wood pellet fuels
from all five states were analyzed in this report.

CHAPTER I

BIOMASS FUELS CONCEPTS AND LITERATURE REVIEW

SOLID BIOMASS FUELS

This section describes the five major and three minor components of solid fuel analysis as relates to combustion performance. The "major" components are noted as such because they are used most often in literature and are the most widely tested [10,15,22,32,36]. The "minor" components are not as widely mentioned, but, they may also be important and more work could be done in this area. The five major components are : ultimate analysis, proximate analysis, higher heating value, moisture content, and, bulk density. The three minor components are : particle size, durability, and, specific density. First, the major components are discussed.

MAJOR COMPONENTS :

Ultimate Analysis -

The ultimate analysis of a fuel is a record of the percent by weight of hydrogen(H_2), carbon(C), nitrogen(N_2), oxygen(O_2), sulfur(S), ash(mineral), and sometimes, chlorine(Cl). Currently, ASTM Standard No. D 3176-84, "Ultimate Analysis of Coal and Coke", is the procedure used for laboratory samples of wood and refuse derived fuel (RDF) biomass fuels. It is usually given on a moisture free

basis. The primary importance of ultimate analysis is in the calculation of air-to-fuel (A/F) ratio. By knowing the percentage of O_2, S, H_2, and, C, and the primary chemical reaction equations, it is possible to calculate the stoichiometric A/F ratio [34]. The stoichiometric A/F ratio is the theoretical quantity of air required to burn all the combustible elements in the fuel if, all the oxygen supplied by the fuel and air were completely consumed.

Another important aspect is that sulfur and chlorine can be a major cause of emission problems, i.e. (oxides and acids containing S and Cl in the flue gasses). Sulfur and chlorine are also a major culprit in boiler flue corrosion due to the acidic nature of their compounds (primarily hydrochloric and sulfuric acids). This will be discussed more thoroughly in the proceeding sections : "Problem Fuels : Emissions / Environmental Standards" and "Cofiring". By comparing any fuels sulfur content with that of coal, one can make both qualitative and quantitative assessments as to its problem nature. This is possible because of the vast data accumulated for coal fired plants burning "high" sulfur fuels. Sulfur content of most wood based fuels is so low that sulfur dioxide and other pollutants are not a problem [15]. Chlorine, like sulfur, is also a very small component of wood biomass (except for saltwater soaked logs), however; chlorine can play a considerable role in the corrosive behavior of refuse derived fuel [41].

Finally, ultimate analysis can be used to approximate the higher heating value of fuels because the individual heating values of the combustible elements, S, H_2, and, C are known. However, this is not the standard method. Errors occur due to the fact that these elements are bound in macro-molecular structures, i.e. cellulose, tars, plastics, etc., that have their own thermo-chemical behavior. These compounds do not necessarily produce heat energy by exothermic reaction with oxygen identically as the individual components do. The primary cause of this is dissociation and "other phenomena" [32].

Table 1, lists the ultimate analysis of a number of different fuels for comparative purposes.

Table 1. Ultimate Analysis Data for Selected Dry Fuels. Sources [2,13,32,43].

Fuel Type	C	H_2	O_2	S	N_2	Cl	Ash
			----	% by wt.	----		
KY,No.9 coal	65.2	4.6	8.4	4.9	1.4	--	15.4
WV,Rank D,coal	84.7	4.3	2.2	.6	1.5	--	4.
Douglas Fir	52.3	6.3	40.5	≈0	.1	--	.8
White Pine	52.5	6.1	41.3	≈0	≈0	--	.1
Black oak	48.8	6.1	45.0	≈0	≈0	--	.1
RDF, Type A	46.0	6.0	34.5	.4	.7	.4	12.0
RDF, Type D	44.0	6.0	32.6	.3	.7	.4	16.0

From Table 1, it is possible to denote some general trends in the three fuel categories represented above. Those categories being, coal, wood, and, RDF biomass. First, coal has a low oxygen and high carbon content compared with wood and RDF. Second, coal and RDF have high ash and sulfur content compared to wood. Finally, it is apparent that only RDF has an appreciable amount of chlorine.

Proximate Analysis -

Proximate analysis of solid fuel is used to determine the percentages of volatile material, fixed carbon, and, ash. Volatile matter is the portion of fuel gasified by pyrolytic action and responsible for flaming combustion. Fixed carbon is that portion of fuel, not pyrolyzed, that burns in solid form (glowing or char combustion). Actually, "fixed carbon" is any combustible residue left after complete elimination of volatiles, it is primarily but not all carbon [32].

Proximate analyses are done under rigid test conditions as prescribed by ASTM Standard No.D 3172-73, "Proximate Analysis of Coal and Coke". The ASTM standard calls for heating the sample at 1740°F for seven minutes. This heating period is what burns or drives off the volatiles.

The fundamental importance of proximate analysis is in the design of combustion systems, especially grates and air handling equipment. This is true for two primary reasons. One reason, is that fixed carbon burns at a much slower rate than volatiles and at a higher temperature [3,4]. This is very useful information for grate or fuel bed designers who must choose materials properly for their expected temperature loading. Secondly, proximate analysis is important for air handling engineers who must determine the correct amount of under-fire and over-fire air for efficient combustion. The under-fire air is used to burn the fixed carbon and the over-fire air is used to burn the volatiles. Engineers must also design fire-boxes, ducts, fans, and pollution abatement devices for the total volume of exhaust gasses. It is well known that matter in the solid state takes up much less volume than matter in the gaseous state. It is known that the volume of gasses from combustion of a low volatile fuel will be considerably less than for highly volatile fuels. This is one contributing factor in the problems encountered in cofiring coal with wood or RDF in a boiler designed originally for coal. Wood and RDF have a much higher yield of gasses for the same heat output required by the boiler. This usually leads to a loss of efficiency and erosion problems due to high gas velocities. The high velocities are coupled with increased particulate, i.e. a "feedback" effect occurs [12]. This topic will be

covered more fully in the following "Cofiring" section.

For many years proximate analyses have been used successfully to determine the ratio of over vs. under fire air for proper combustion. This is done simply on the basis of knowing the percentage of fixed carbon to volatile in the fuel, i.e. once a total quantity of deliverable air(excess air) is chosen, it is split into two air streams, under-fire and over-fire, in the same ratio respectively as volatile to fixed carbon. This works very well in coal combustion where the percent volatiles is usually low, however, there is some doubt now as to the applicability of this method for higher volatile fuels such as wood and RDF.

Current literature shows that there really is no "true" ratio of fixed carbon to volatile in any particular solid fuel [29,40]. During pyrolysis; temperature, rate, and, inert gas percent, all affect the final quantity of fixed carbon left after "complete" pyrolysis [40]. That is, these three factors all tend to decrease char yield when they are increased. Char yield may be as little as one half the yield from proximate analysis (ASTM method) [40]. Fuel bed temperatures in many hogged fuel spreader-stoker boilers are on the order of 1740-2550xF, which are obviously much greater than the temperatures called for in the ASTM standard.

Fig. 1, follows and is an adaptation of the data in [29].
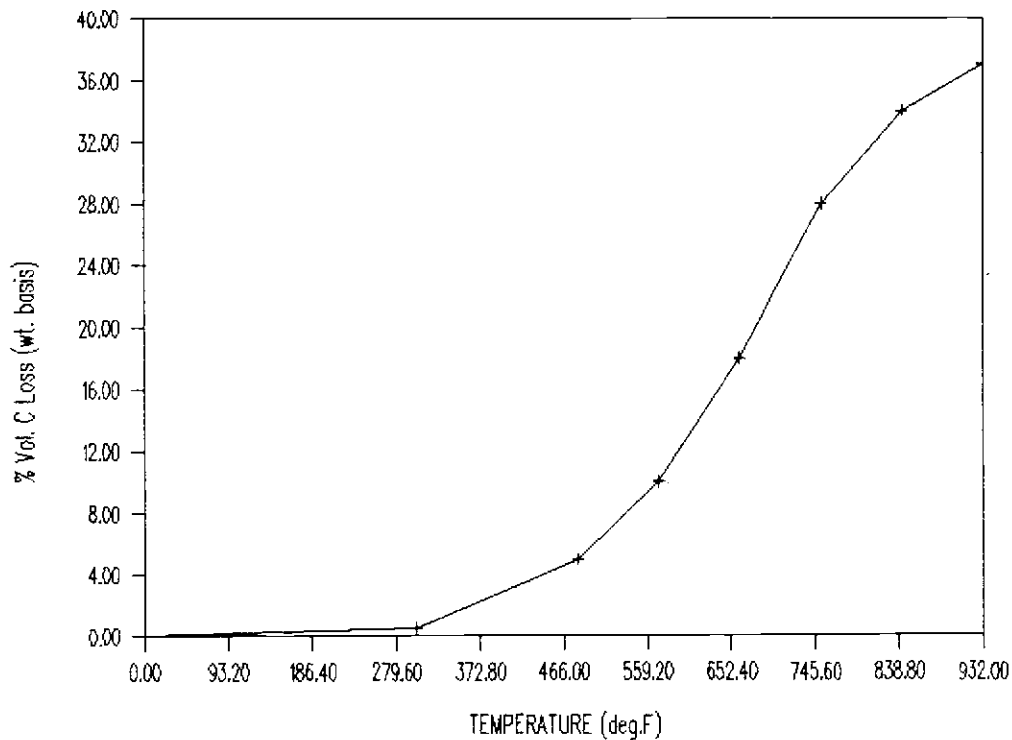
Figure 1. Emission of Volatile Carbon (Vol. C) as a Function of Temperature for Douglas Fir Foliage. Source [29].

It clearly shows that the quantity of volatile carbon, (and it is presumed the other volatile elements or compounds), is a function of temperature. Reference [29] was not clear on the definition of "volatile carbon" as opposed to simply "volatiles". This supports the work in [40], and is one area of research this author feels is currently neglected in biomass fuels studies today. It is important to be able to calculate the optimal split of over

and under-fire air for combustion efficiency and emission
control. It may be that the current ASTM method is
inadequate in this regard. This does not detract from the
fact that proximate analysis is still a good way to compare
different fuels, since the test is highly reproducible.

Table 2, lists some proximate analyses data for
selected biomass fuels.

Table 2. Proximate Analyses of Selected Dry Biomass
Fuels. Sources [3,28,31].

Fuel Type	fixed carbon	% by wt. volatile matter	ash
RDF Type A	13.0	75.0	12.0
RDF Type D	13.0	71.0	16.0
KY, No. 9 coal	46.1	38.5	15.4
Cedar (wood)	21.0	77.0	2.0
Douglas Fir (wood)	13.7	86.2	.1

Table 2, shows the considerable differences between
RDF, coal, and wood, when it comes to proximate analysis.
The coal is much higher than wood or RDF in fixed carbon,
but is similar in ash to RDF. The two species of wood
shown, illustrate how variable the ratio of fixed carbon to
volatile matter and ash content can be in different species
of wood.

<u>Higher Heating Value</u> -

Higher heating value is primarily used as the basis for
energy balance and/or efficiency calculations for boilers
and furnaces and for multiple fuel comparisons.

Higher heating value(HHV), is the quantity of heat
released during complete (constant volume) combustion
of a fuel, when the products of combustion are brought to
the same equilibrium temperature as the initial constituents
[7,32,34]. This represents the maximum available energy
output that can be expected of the fuel by combustion
processes. It is called by a variety of names, some of
which are : "gross heating value", "gross calorific value",
"gross heat of combustion", or less frequently, "internal
energy of reaction".

HHV is found by laboratory testing, usually in an
adiabatic bomb calorimeter. The applicable ASTM Standard is
No. D 2015-77,"Gross Calorific Value of a Solid by the
Adiabatic Bomb Calorimeter", and is generally performed on
an oven-dry sample. It is assumed that the water formed by
combustion of hydrogen is in the liquid phase at final
equilibrium, this implies that the heat of vaporization of
water is included in the higher heating value. This heat
(or enthalpy) is usually denoted, h_{fg}, in units of Btu/lbm.
The heat of vaporization, (h_{fg}), can be found in saturated

steam tables and has a value of 1055(Btu/lbm) at 68°F [25].

There have been a number of other heating values reported such as : 1) net or lower heating value(LHV), sources : [4,5,7,15,25,32], and, 2) lower heating value two(LHV2), sources : [21,24]. These are defined primarily to account for the energy losses due to the water vapor both formed during combustion and carried as moisture in the fuel. Remember, higher heating value (HHV) is based on all water formed being in the liquid state.

For LHV, the cited references generally agree that lower heating value is calculated by subtracting the latent heat of vaporization (h_{fg}) from the higher heating value, however they do not agree on the value of h_{fg}(Btu/lbm). The range of values are, 1050(Btu/lbm) [32], to, 1059(Btu/lbm) depending on the choice of reference temperature [4]. Other literature suggests that the constant is not h_{fg} at all, but, a value of 1030(Btu/lbm) [7]. This analysis assumes a HHV based on a 68°F temperature state, and some calculations (not available in [7]) to change from a constant-volume process(bomb calorimeter) to a constant pressure (atmospheric) process. These differences are not extreme, and, the important thing to remember while performing thermodynamic calculations for any system is that the **same reference state** be used throughout the work.

Lower heating value two(LHV2), is a sophisticated modification to the HHV and accounts for the fact that some

of the water in wood or any solid fuel is "bound" by
molecular forces that require more energy to break, i.e.
vaporize, than if the water were "free". This idea is
presented in detail in a later sub-section titled, "Moisture
Content".

Table 3, lists higher heating values for a number of
wood, coal, and, RDF fuels. The samples were chosen to
represent the range of HHV's for these fuel types.

Table 3. Higher Heating Value of Selected Biomass
Fuels. Sources [7,13,32,43].

Fuel Type	HHV (dry-basis) (Btu/lbm)
WV, Rank D coal	14,730
ND, Rank J coal	7,210
RDF, Type A	8,100
RDF, Type D	7,700
RDF, Type 3	9,796
Sitka Spruce(wood)	8,100
Ponderosa Pine(wood)	9,100 - 9,140
Ponderosa Pine(bark)	9,415 - 9,616
Douglas Fir(wood)	8,318 - 9,200
Douglas Fir(bark)	9,373 - 10,845
Western Hemlock	8,626

From Table 3, the average (wood-only) HHV is

8,747(Btu/lbm), for RDF the average is 8,532(Btu/lbm) and for coal it is 10,970(Btu/lbm). This illustrates how close RDF and wood biomass can be in higher heating value and how coals HHV is larger than either RDF or wood by approximately twenty percent. Remember, these values are only representative and by no means are the comparisons made definitive, only illustrative.

Moisture Content -

Moisture content (MC) of a solid fuel is one of the most critical parameters controlling combustion [4]. It affects the rate of burning, flaming temperature, and volume of gasses during combustion, and consequently changes boiler performance and emissions. It has been noted by several authors that combustion of hogged wood fuel in typical boilers will cease or "black-out" at approximately 67 percent moisture content wet-basis [21,22,23]. Black-out usually necessitates the use of additional fossil fuel to maintain combustion such as oil or natural gas. Moisture also lowers the heat or Btu content per pound of fuel, which means a greater volume and mass must be fired to achieve the same steam or heat load as compared to dry fuel. The following section describes the typical calculations to account for heat losses due to moisture content and some of

the current work being done to study the effect of moisture on combustion. The applicable ASTM Standard is, No. E 871-82, "Moisture Analysis of Particulate Wood Fuels".

Nomenclature :

Moisture in fuel is described by one of two equivalent ways, either on a "wet" or "dry" percentage basis. **Wet Basis(wb)** : This is defined as the weight of water in the sample (water weight), divided by the total sample weight (sample weight) which includes dry fuel plus water. Note, this is sometimes called an "as-is" basis.

$$\%MC_{wb} = (\text{water weight} / \text{sample weight}) \times 100 \qquad (1)$$

Dry Basis(db) : Moisture content (MC) on a dry basis is the weight of water in the sample divided by the dry sample weight.

$$\%MC_{db} = (\text{water weight} / \text{dry sample weight}) \times 100 \qquad (2)$$

The conversion between $\%MC_{wb}$ and $\%MC_{db}$ can be performed as follows :

$$\%MC_{wb} = (\%MC_{db} / (\%MC_{db}+100)) \times 100 \qquad (3)$$

and,

$$\%MC_{db} = (\%MC_{wb} / (100-\%MC_{wb})) \times 100 \qquad (4)$$

Both measures of moisture content are used widely in the literature with no definite preference shown.

The following section describes moistures effect on the performance of solid fuels, it is broken down into sections by major topic as follows : 1) <u>Heat Losses and Heating Value Analysis</u>, 2) <u>Volumetric Expansion</u> , 3) <u>Flaming Temperature</u>, and, 4) <u>Rate of Combustion</u>.

1) <u>Heat losses and heating value analysis</u>. The following analysis draws heavily from the work given in [4]. Three energy loss terms will be developed here, they are, a) energy used to vaporize water formed during combustion, b) energy used to vaporize the "free" and "bound" water in the fuel respectively.

a) **Energy used to vaporize water formed during combustion.** Let, Q_{H2}(Btu/hr), be the rate of heat loss due to vaporization of the water formed during combustion by the oxidation of hydrogen; then, Q_{H2} can be calculated as follows :

$$Q_{H2} = M_{H2} * h_{fg} \tag{5}$$

where, Q_{H2} = rate of energy required to vaporize water at the reference state of 68°F, M_{H2} = mass rate of water formation by combustion, h_{fg} = 1055(Btu/lbm-H$_2$O) at 68°F. The lower heating value, as mentioned in the previous section-"Higher Heating Value", can now be calculated as follows :

$$LHV = HHV - Q_{H2}/M_{dw} \tag{6}$$

where, LHV = lower heating value (Btu/lbm-dry fuel), HHV = higher heating value (Btu/lbm-dry fuel), M_{dw} = mass rate of dry fuel into combustor. Note that Q_{H2} is divided by M_{dw} to keep LHV on a "dry" basis consistent with the definition of HHV.

b) Energy used to vaporize the "free" and "bound" water in the fuel. The following discussion deals specifically with moisture in wood, yet, there is no reason why it is not generally applicable to any solid fuel that is porous. First, the distinction between "free" and "bound" water must be made. Bound water is formed by adsorption along the interface with cell walls and is rarely more than ten molecules thick. Adsorption, is the take-up of water by chemical reaction, i.e. heat is actually evolved by

adsorption, energy that later must be replaced if the water
is to vaporize. Free water is formed by absorption.
Absorption is a physical process, due to capillary action,
of water take-up into the porous structure of a solid.
There is only a very small emission of heat due to
absorption and it is considered negligible compared to
adsorption. There is always some water vapor in the porous
cell structure of a fuel, but its effect is also considered
negligible.

The moisture content of wood at which all the free
water is gone but the bound water remains, is called the
fiber saturation point (FSP). For wood, the FSP is
approximately, $\%MC_{wb}$ = 21.9. The energy required to bring
the bound water to the energy level of the free water is not
a constant, but a function of moisture content (below FSP).
This function is different for every fuel and can only be
determined experimentally. The equation for the average
energy required to bring the bound moisture in Douglas Fir
wood to the energy level of the free water, NOT to vaporize
it is found in [4]. H_{bw}, is this required energy and has the
units of (Btu/lb). The equation for H_{bw} is a long polynomial
expression from regression analysis and won't be copied
here, however, Fig. 2, graphically shows the results.
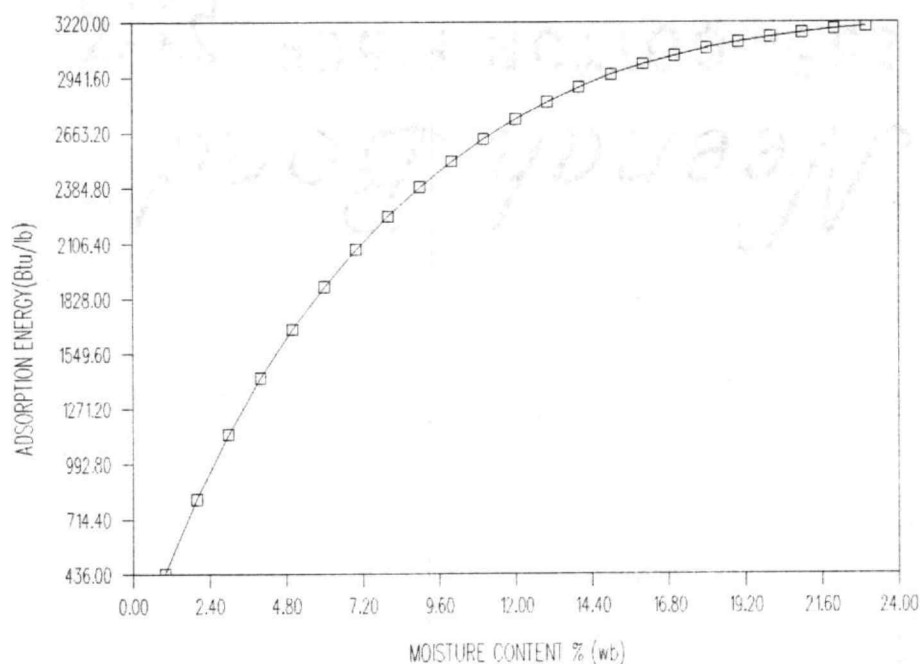
Figure 2. H_{bw} or the Adsorption Energy Versus Moisture Content (wet-basis). Source [4].

It is now possible to define lower heating value two(LHV2), as was mentioned in the previous sub-section, "Higher Heating Value". LHV2 is simply LHV minus the energy required to vaporize all water carried in by the fuel, both bound and free. The expression for LHV2 is given as :

$$\text{LHV2} = \text{LHV} - ((H_{bw} + 1055) * (MC_{db})) \tag{7}$$

where, LHV2 = lower heating value two(Btu/lbm-dry

wood), H_{bw} = specific energy loss due to bound

water(Btu/lbm-water), 1055 = h_{fg}(Btu/lbm-water), and, MC_{ab} =

moisture content dry-basis(lbm-water/lbm-dry wood). Fig. 3

shows the effect of moisture on the three heating values as

defined above.
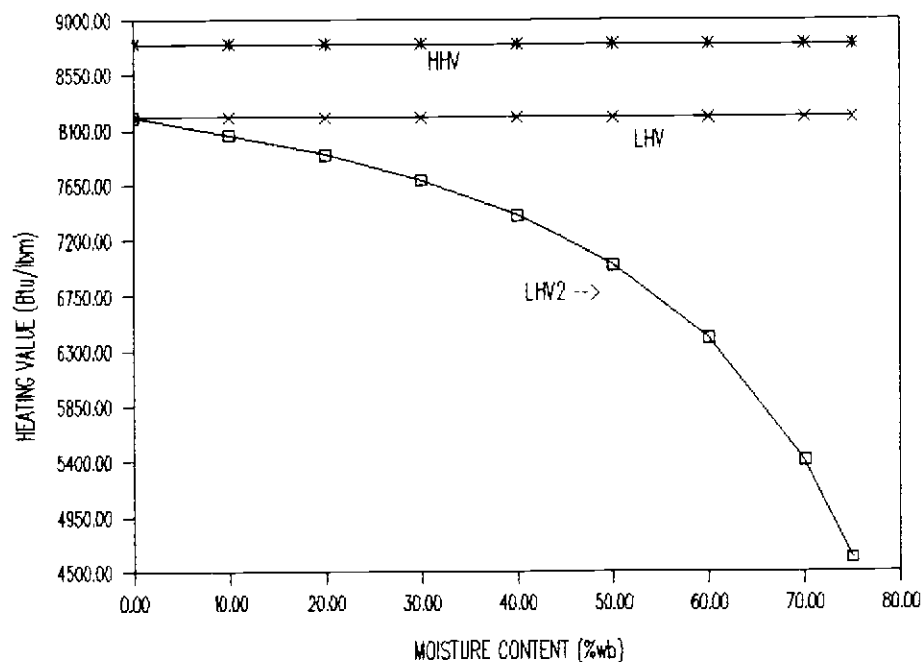
Figure 3. The Effect of Moisture on the Heating
Value(s) of Wood Biomass. Based on Douglas Fir with an
Assumed Higher Heating Value of 8800 Btu/lbm.

Fig. 3, shows that the bound water has the non-linear effect of rapidly decreasing the apparent heating value of a fuel, whereas the effect due to latent heat of vaporization is constant.

The energy required to vaporize the free water plus the bound water that has been brought to the energy level of the free water can be calculated as follows :

$$Q_{fv} = M_t * h_{fg} \qquad (8)$$

where, Q_{fv} = energy rate required to vaporize the free water and bound water that has been raised to the energy level of the free water, i.e. it is now "free"(Btu/hr), M_t = total mass rate of water brought in by the fuel, units are (lbm/hr), h_{fg} = 1055(Btu/lbm-water), as usual.

So in total, the rate of energy required to bring all moisture to the vapor state at 68°F is Q_{tot}, where :

$$Q_{tot} = Q_{fu} + Q_{H2} + Q_{bw} \qquad (9)$$

It should be noted that these losses occur in the combustion chamber. When vaporization is calculated or occurs at 68°F there is no change in gas temperature, thus, no increase in the available energy of the gasses is realized. That is why this total heat of vaporization is considered a loss. However, boiler exhaust temperatures are

usually on the order of 400°F [35], and water vapor at 400°F
and 1 atmosphere is superheated. This means that even more
energy is lost due to combustion heat wasted on superheating
vapor that is sent out the stack.

2) Volumetric Expansion. The effect of moisture on the
volume of flue gasses can best be understood by noting that
water undergoes an expansion of approximately 5700 times its
original volume when it goes from being a liquid to being a
vapor in typical furnace operation [4,42]. An easy way to
estimate this expansion is to look up the specific volume of
water in the liquid state, $v_f(ft^3/lbm)$, at the reference
temperature 68°F, then, find v_g (gaseous specific volume)
in the superheat tables at atmospheric pressure and the
desired/estimated maximum combustion gas temperature. Next,
compute the ratio of (v_g/v_f) where this value is the expected
volume expansion parameter. For example, data from [34]
gives as values for v_f and v_g :

$$v_f(68°F,sat.) = .016(ft^3/lbm)$$
$$v_g(14.7psi,1600°F) = 83.47(ft^3/lbm)$$

so,

$$v_g/v_f = 5216.9 \ (vol.gas/vol.liquid) \tag{10}$$

Note that this calculated value is close to the number cited
above, and is primarily a function of the chosen superheat

temperature.

The main problem associated with this enormous expansion is the associated _increased gas velocity_. Using the simplest form of the Continuity Equation, $Q = VA$, where Q = volumetric flowrate, V = velocity, and, A = area, one can see that if Q is increased while holding the area A constant, the velocity V must increase _proportionately_.

There are a number of problems caused by increased gas velocities, especially if the furnace and/or boiler was not designed adequately for high moisture fuel. These problems are : 1) Reduced combustible gas and combustible particulate residence time, i.e. increased particulate carryover and unburned gasses escape [12,15]. 2) Increased erosion by particulate abrasion action, especially in high ash fuels [22]. 3) Emission control devices cease to function properly if undersized for such volumetric and mass particulate loading. It may also be necessary to increase the size of induced draft fan motors to "keep-up" with the required flow [4,12,15]. 4) There is a potential for increased flue exhaust gas temperature, thus, increased heat losses by sensible and latent enthalpies [12,42].

3) _Flaming Temperature_. The method of calculating adiabatic flame temperature by the "free energy minimization" method is described in [34]. Adiabatic flame temperature is the maximum temperature that can be achieved

for a given fuel [34]. It is based on the theoretical

concept of no changes in kinetic or potential energy of the

reactants, all energy is released as heat. This condition

is obviously never met in "real-life" , but is very useful

for comparing different fuels potential heat transfer

properties, i.e. higher flame temperature means greater

temperature gradients to drive heat transfer from gasses to

water in boiler tubes. A computer model was used to carry

out the necessary calculations of AFT. After the model was

run for a number of parameter changes, linear regression was

performed on the simulated data. These predictor equations

for Douglas Fir, Poplar, Yellow Pine, Hickory, and Black Oak

are presented in [34]. The largest deviation of predictor

equation vs. computer simulation was four percent, this is

true for the following parameter ranges : 1) percent excess

air from 11% to 100%, 2) moisture from 0% to 50% wet-basis.

Fig. 4, shows the results of the analysis of the effect of

moisture on the adiabatic flame temperature for Douglas Fir

and Yellow Pine. It is interesting that the effect of

moisture on flame temperature is almost entirely linear. If

you calculate the percentage temperature decrease from

fifteen to fifty percent moisture for Douglas Fir and for

twenty to fifty percent moisture for Yellow Pine the

temperature decrease is twenty two percent. That is, the

flame temperature is decreased by twenty two percent in both

cases. This seems considerable, but the results might not

be as dramatic in a "real" situation, due to many inter-related heat loss mechanisms [34]. This type of study will become much more relevant as attempts are made to squeeze more and more energy out of wet fuel that has in the past been considered waste, i.e. hogged fuel being burned because it is cheaper than landfilling.
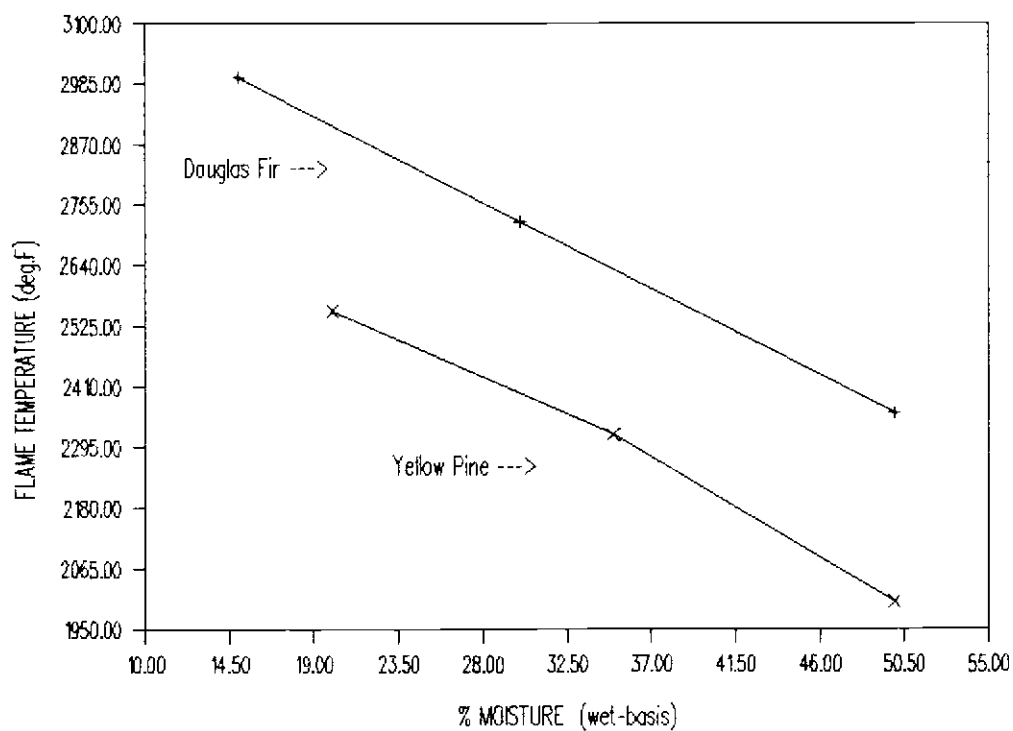
Figure 4. The Effect of Moisture on the Adiabatic Flame Temperature of Yellow Pine and Douglas Fir Wood.

4) <u>Rate of Combustion</u>. Most of the combustion experiments examining the rate of burning have been carried out on small, usually cylindrical or cubic, single particles [14,17,18,30,31]. These tests are performed in very sophisticated devices where variables of temperature, mass loss, and composition, can be controlled and measured accurately. Tests such as these may not model spreader-stoker boilers, wood stoves, or dutch ovens, but the information is still useful, qualitatively, if not quantitatively.

A study on the effect of moisture on sugar pine and white oak under conditions meant to simulate a stoker-type furnace was reported by [30,31]. A single round particle was subjected to parametric variations in initial temperature, Reynolds number, oxygen concentration, <u>moisture</u>, wood type, and, size (10 and 20 mm diam.).

The results of this study for moisture variation are very interesting. As one would expect, moisture does slow the rate of mass loss or burning. At zero moisture the peak reactivity is .045s^{-1}, at 13%MC$_{wb}$ it is .031s^{-1}, and, at 71%MC$_{wb}$ the peak reactivity is .018s^{-1}. Reactivity in this case is defined as the time rate of mass loss divided by the initial mass, sometimes called the normalized reactivity.

For a saturated 10mm pine specimen, moisture = 71%wb, the normalized rate of burning or reactivity rises sharply to a short, constant plateau, then falls steadily until the

end of the burn. Previous researchers had postulated that there would be very little combustion until the "free" water was evaporated [30]. The data from [30,31] does not support this. There was also direct visual observation of flaming to support the fact that combustion took place virtually during the entire experiment.

Fig. 5, is an adaptation from [6], that shows the effect of moisture on normalized burning rate.
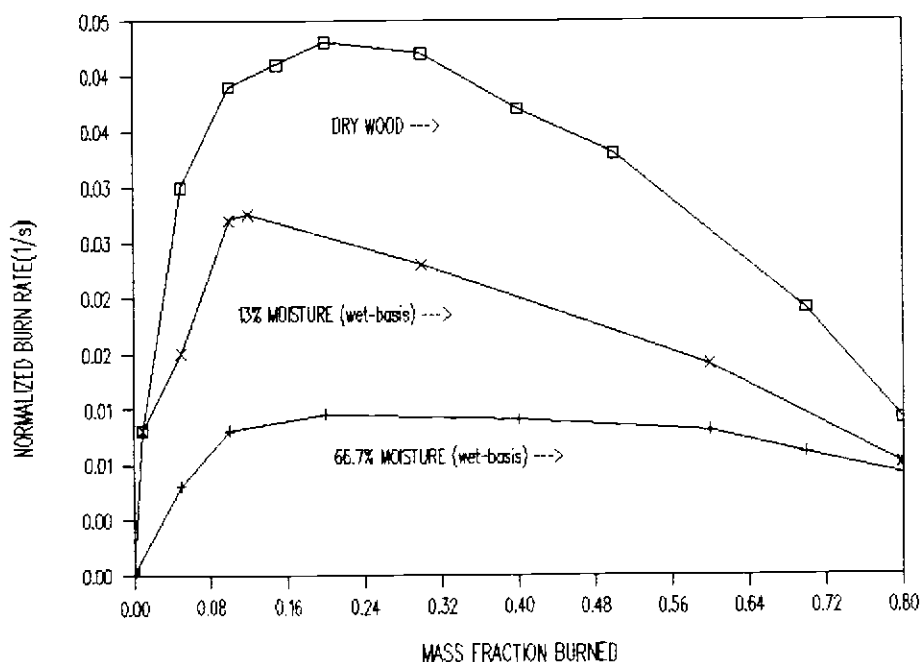
Figure 5. Normalized Burning Rate (Reactivity) for a Pine Specimen at Different Moisture Contents.

A very similar study, but on 1.5cm pine cubes at 1454xF, was performed [14]. The general result is the same, i.e. moisture slows the rate of burning. The data was displayed differently and it gives new insight to this problem. Fig. 6, is adapted from [37]. It shows that the total burn time is virtually a linear function of moisture.
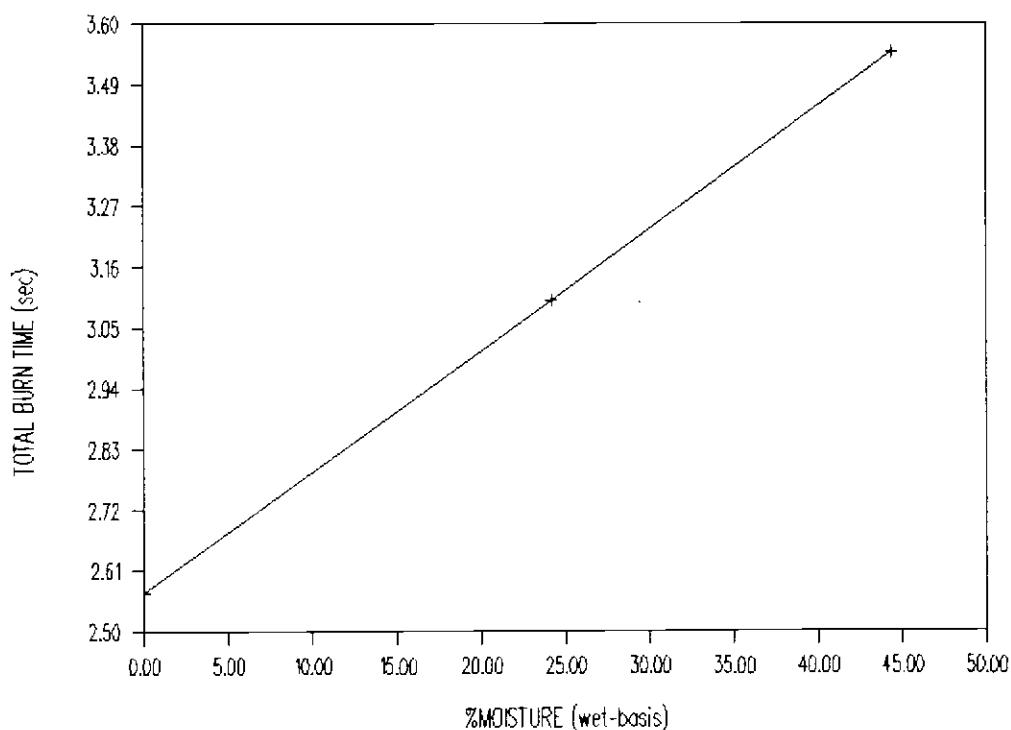
Figure 6. **Total Burning Time as a Function of Moisture Content for 1.5 cm Pine Cubes.**

Bulk Density -

Bulk Density is used to determine the heat content per unit volume of fuel or Q_v(Btu/ft^3). Q_v is used to compare different fuels heating values. There are two basic

concerns, 1) Will the feed system be able to carry the necessary volume of fuel to meet steam or heat load? 2) Can enough fuel be stockpiled to meet demand for extended periods? (especially important for pellet fuels which must be protected from moisture at any cost or they will disintegrate).

Q_v is determined as follows :

$$Q_v = HHV * D_b \qquad\qquad (11)$$

Where, D_b = bulk density(lbm/ft^3), HHV = higher heating value(Btu/lbm), and Q_v = volumetric heat content(Btu/ft^3). D_b is determined by an ASTM technique requiring a container with a volume of one cubic foot(ft^3) as the basis of measurement and accurate weighing. The ASTM Standard is No. E 873-82, "Bulk Density of Densified Particulate Biomass Fuels". A standard was not found for non-densified biomass fuels.

Bulk Density is a requirement for the Association of Pellet Fuel Industries (APFI) Standard, No. APFI-PF-1-88 [36].
This standard requires a bulk density of forty (lbm/ft^3) for residential grade pellet fuel. The Fiber Fuels Institute (FFI), recommends a bulk density of atleast thirty six(lbm/ft^3) [9]. Table 4, lists the high and low values of bulk density reported for various fuels.

Table 4. High and Low Range of Bulk Density for
Selected Biomass Fuels.   Sources [9,13].

FUEL TYPE	D_b (low) (lbm/ft^3)	D_b (high) (lbm/ft^3)
WOOD (hogged)	10	20
WOOD (pellet)	32	42
WOOD (chips)	18	26
RDF (all classes)	1.9	12.8

The following discussion on the four "Minor" components
of fuel analysis relates primarily to pelletized fuel, but
some parts are applicable to non-densified fuels.

MINOR COMPONENTS :

Particle Size -

Particle Size is important for two reasons. One reason
is the effect of size on fuel feed systems. This is not so
critical for belt/conveyor type feeders, but is very

important for auger type feed systems as found in pellet stoves. Auger systems are susceptible to bridging if the fuel is small enough to lodge between the auger tines and feed tube wall.

Secondly particle size is important is for combustion efficiency and erosion concerns. This is true for pelletized and, as-is fuels, i.e hogged wood, chips, RDF,etc. "Fines" are any particle less than 1/4 inch [33]. There are two major concerns with the quantity of fines in a fuel source.

1) Fines and the rate of combustion. Since wood and RDF are usually 70% volatile matter or more, the rate of combustion is directly proportional to how quickly the required heat reaches and pyrolyzes the volatile material [33]. The rate of heating is dependent on the exposed surface area per unit volume of the particle. Larger particles have a smaller ratio of surface area to volume and tend to insulate themselves progressively during combustion by formation of a char layer with low thermal conductivity [19,33]. Therefore, smaller particles are more reactive than larger particles. This increased rate of combustion requires greater air supply and this in turn can decrease efficiency by a number of mechanisms, being, a) greater flue gas temperature at exit, b) less particle residence time (especially the fines), and, c) erosion due to increased gas velocities.

2) <u>Fines effect on transportation and storage</u>. As particle size decreases there is an increased "dust" problem due to wind carried biomass. There is a greater fire hazard due to the explosive nature of fine particulate fuel.

<u>Durability</u> -

Pellet durability is a measure of a pellets propensity to produce fines while under physical agitation. At present, there is no ASTM Standard available, however, OSU is currently performing tests which may become part of an ASTM Standard. Reference [36], states that pellets must have fewer than one percent (1%) by weight flow through a one-eighth inch (1/8in.) screen to meet their residential pellet standard. Another source, [32], states that the friability (another common name for durability), is measured as the "percent unbroken". [32], does not state how one is to determine this percent unbroken, but lists high and low values for wood pellets as, 98 and 90 percent respectively.

From the previous discussion, "Particle Size", it is obvious why durability is a concern for pellet manufacturers, stove manufacturers, and consumers. Pellets, many times, are purchase specifically for physical properties associated with their high specific density, i.e.

high Btu value per volume, "feedability", and, general ease
of handling. If they break up during normal handling this
degrades the pellet quality on all these accounts and will
probably degrade combustion efficiency as noted above in the
discussion on "Fines and the rate of combustion".

Specific Density -

Similarly to pellet durability, this author was unable
to find a nationally recognized standard for biomass pellet
specific density. Neither was it mentioned in [32] or [36].
Specific density is a measure of a single pellets mass per
unit volume, such as , (lbm/ft^3). Biomass users are usually
concerned with bulk density since they deal with quantities
of fuel on a "macro" scale. Bulk density will help them
size feed systems, design grates, and determine volumetric
firing rates to maintain steam load, etc. Specific density
is probably an important independent variable when it comes
to single particle combustion kinetics, but again, virtually
all residential or commercial users burn pellets on a
"macro" scale. There may be some good reasons to be
concerned with specific density and combustion, but the
literature does not support any at present.

COMBUSTION OF BIOMASS FUELS

Much of the available literature on biomass combustion deals with the thermochemistry of burning wood. The following material discusses the fundamental relationships and processes as we understand them now. Since wood, corn husks, straw, refuse derived fuel (RDF), etc., are all primarily composed of hydrogen(H_2), carbon(C), and oxygen(O_2), the fundamentals of wood combustion also describes the fundamentals of combustion of these other biomass fuels.

Biomass combustion is an extremely complex phenomena by which a solid fuel is thermochemically oxidized producing heat and gaseous by-products. There are really two approaches to understanding biomass combustion, one is extremely complex and the other relatively simple. The complex approach attempts to describe all intermediate physical and chemical reactions of combustion as they occur in time and space. The simple approach is based on the thermodynamic principle of "state". This principle allows us to determine information about a process such as the total heat flux from biomass combustion by simply knowing the beginning and ending "states" of the system. It is only necessary to know two of the following properties, i.e.

temperature, pressure, enthalpy, specific volume, entropy, and chemical composition (of reacting systems) for the complete state of a system to be determined. This is the analytical approach used throughout this thesis. For combustion and other phenomena this is sometimes called the "black-box" method because only the beginning and ending states of the process are analyzed, not what occurred intermediately. It is not that knowing what is occurring inside is not preferred, but the scope of analytic and experimental skills to perform such in-depth study is overwhelming.

THE THREE MAIN STEPS :

There are three main steps in biomass combustion [40]. They are : 1) drying, 2) pyrolysis and flaming combustion, 3) fixed carbon combustion. It should be noted that in a fuel bed, such as found in a spreader-stoker or dutch oven, these three processes are occurring simultaneously, but in different locations.

1) DRYING - Since most biomass contains water, this is a very critical step. Free and bound water must be evaporated before sufficient temperatures for steps 2 and 3 occur. This topic is covered in a previous section titled, "Moisture Content".

2) PYROLYSIS AND FLAMING COMBUSTION - Pyrolysis is

the chemical degradation of a solid fuel, due to heating, that produces char (fixed carbon) and combustible vapors (volatiles). Pyrolysis consists of endothermic and exothermic stages.

For wood the endothermic stage has two distinct temperature ranges [2,23]. For temperatures less than 392°F, water vapor, formic acid, and acetic acid are released from the fuel. For temperatures between 392°F and 536°F, water vapor, carbon dioxide, carbon monoxide, and a number of organic acids are released. This is the "slow pyrolysis" phase where largely non-combustible gasses are formed [2].

The exothermic stage of pyrolysis occurs between 536°F and 932°F [2,23]. This is the "fast" or "active" pyrolysis zone. Highly flammable gasses such as carbon monoxide, methane, aldehydes, methanol, and hydrogen are released, also, highly flammable tars remain in the solid phase as residue.

When sufficient oxygen and heat is present, the gaseous volatile components released during the fast pyrolysis will burn in flaming combustion. This provides a source of heat to continue the pyrolysis (heat the solid) and increase the overall rate of reaction.

3) FIXED CARBON COMBUSTION - Fixed carbon combustion, also known as glowing combustion, is an exothermic process occurring at temperatures above 932°F [2]. This type of

combustion is typically recognized as charcoal briquets used in a bar-b-que. For most biomass, fixed carbon represents only 10-20 percent of the solid fuel, see Table 2. However, this fixed carbon combustion acts as the primary source of heat for the raw (cold) fuel that is usually added on top of the fuel pile in grate-type systems. Glowing combustion releases enough energy to vaporize moisture and volatiles in hogged wood fuel with up to 50 percent (wet-basis) moisture content [40]. The energy from flaming combustion is not needed to dry the fuel [40].

There is a discrepancy in the literature as to the products of glowing combustion. Above 932°F the primary products are carbon dioxide, water, and oxides of nitrogen [23]. [32], states that above 1650°F the surface reaction between oxygen and solid carbon is predominantly to carbon monoxide. In actual spreader-stokers and other boilers the temperature on the grate are usually in excess of 1650°F [40]. This apparent discrepancy may be due to the fact that [23] assumed an oxygen rich atmosphere for the glowing combustion and [40] may have assumed an oxygen starved (reducing) environment, or it may be due to the temperature differential. Neither text was very clear on this point.

SIMPLE COMBUSTION MODEL AND EFFICIENCY :

Now consider the simplest chemical combustion model.

Since the combustible elements of biomass fuel are primarily

carbon and hydrogen (see Table 1) we can model the

combustion by two simple stoichiometric equations. One

equation for the oxidation of carbon and one for hydrogen

[15].

reactants   products

$$C + O_2 \quad \text{-----}> \quad CO_2 \tag{12}$$

heat release = 14,100 Btu/lb [29]

reactants   products

$$H_2 + 1/2O_2 \quad \text{-----}> \quad H_2O \tag{13}$$

heat release = 61,000 Btu/lb [29]
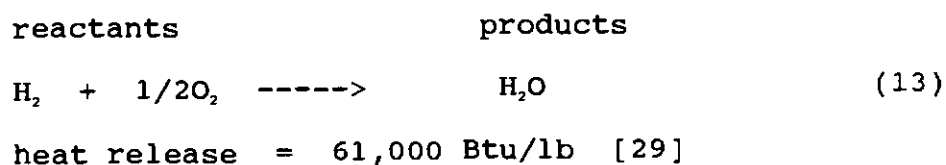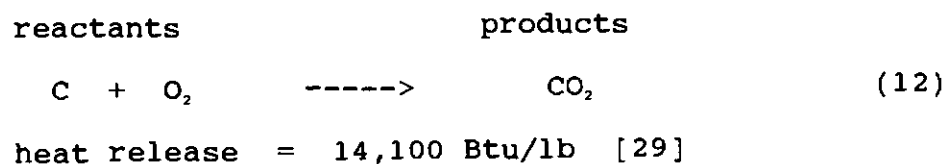
Equations 12 and 13, adequately describe the overall

combustion process if the process is 100 percent thermally

efficient and there are no other combustible elements such

as sulphur and nitrogen. Since sulphur is sometimes present

in biomass fuels it may be necessary to include the

following equation for the oxidation of sulphur to sulphur

dioxide :

reactants   products

$$S + O_2 \quad \text{-----}> \quad SO_2 \tag{14}$$

heat release = 4000 Btu/lb [29]
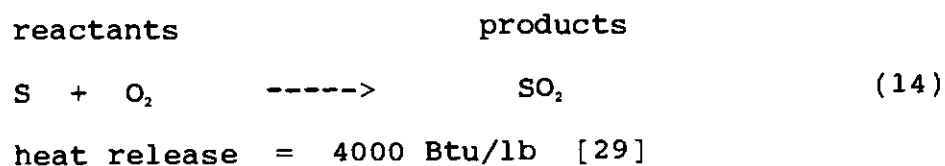
EFFICIENCY - When combustion is 100 percent efficient
it means that all combustible elements have been fully
oxidized to products releasing the greatest possible heat
energy. For biomass fuels this implies that all carbon has
been converted to carbon dioxide and all hydrogen to water.
Maximum temperature will correspond to this point because
optimum efficiency corresponds to reactions with the
greatest heat release per pound of fuel.

Flame Temperature - Combustion or flame temperature
in "real-life" burners will always be less than the
calculated adiabatic flame temperature (AFT), because of
heat losses. These losses include : 1) incomplete carbon
and hydrogen oxidation, 2) combustion less than
instantaneous, 3) radiation, convection, and conduction
losses, 4) other causes including inert ash heated in the
burner. A model of adiabatic flame temperature using the
method of "free energy minimization" was developed in [38].
Simple algebraic equations for estimating the AFT for
Douglas Fir, Yellow Pine, Poplar, Hickory, and Black Oak
were developed. These equations could be very useful for
comparing real burner temperatures to the AFT as a measure
of efficiency.

Carbon Monoxide - Combustion is never 100 percent
efficient in real life. Another indication of this besides
the AFT is the amount of carbon monoxide (CO) in the
exhaust. Remember that one product of fast pyrolysis and

possibly even glowing combustion is carbon monoxide. If this CO is not later oxidized to CO_2 during combustion then it exits the burner as a heat loss. This loss is equal to 4340 Btu per pound of carbon in the fuel [4]. This is true because the oxidation of CO to CO_2 releases 4340 Btu/lb by the following equation :

reactants   products

$$CO + 1/2O_2 \quad -----> \quad CO_2 \qquad (15)$$

heat release   = 4340 Btu/lb
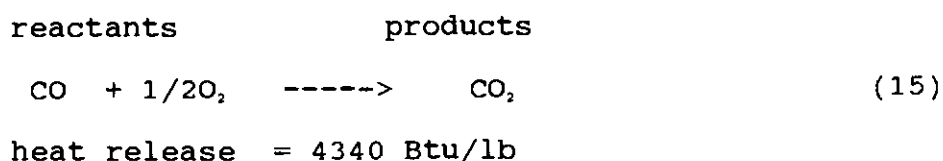
<u>Unburned Hydrocarbons and Organic Compounds</u> - This includes the gaseous products of slow and fast pyrolysis which for any number of reasons are not broken down and completely oxidized. They include hydrocarbons, and a wide class of organic compounds called polycyclic organic matter (POM) [6]. These emissions can be substantial in low efficiency burners such as wood-stoves that are "stoked or damped-down" and other poorly designed equipment. In most commercial and newer residential appliances there is not much heat loss from these unburned emissions.

Fig. 7, is a schematic representation of the primary processes that occur in a fuel bed such as found in a spreader-stoker or dutch-oven type furnace. The curves to the right of the picture and text show how combustion gas

composition and temperature vary with height in the fuel
bed. Fig. 7, shows approximately where the idealized
combustion equations (Eqns. 12, 13, and 15) occur within a
fuel bed. Note that this is a schematic representation and
the actual distribution of where the combustion reactions
occur depends on many things; some are, percent excess air,
ratio of over to under fire air, and fuel moisture content.

EFFLUENT   FUEL (overfed)

OVERFIRE AIR

BED TOP

FUEL BED

GRATE

SECONDARY OXIDATION ZONE

$2CO + O_2 \rightarrow 2CO_2$

$C + O_2 \rightarrow CO_2$

$H_2 + 1/2O_2 \rightarrow H_2O$

PREHEAT ZONE

ignition plane

REDUCTION ZONE

$CO_2 + C \rightarrow 2CO$

OXIDATION ZONE

$C + O_2 \rightarrow CO_2$

ASH LAYER

CO_2

CO

TEMP.

O_2

0   COMPOSITION AND TEMPERATURE PLOTS

UNDERFIRE AIR
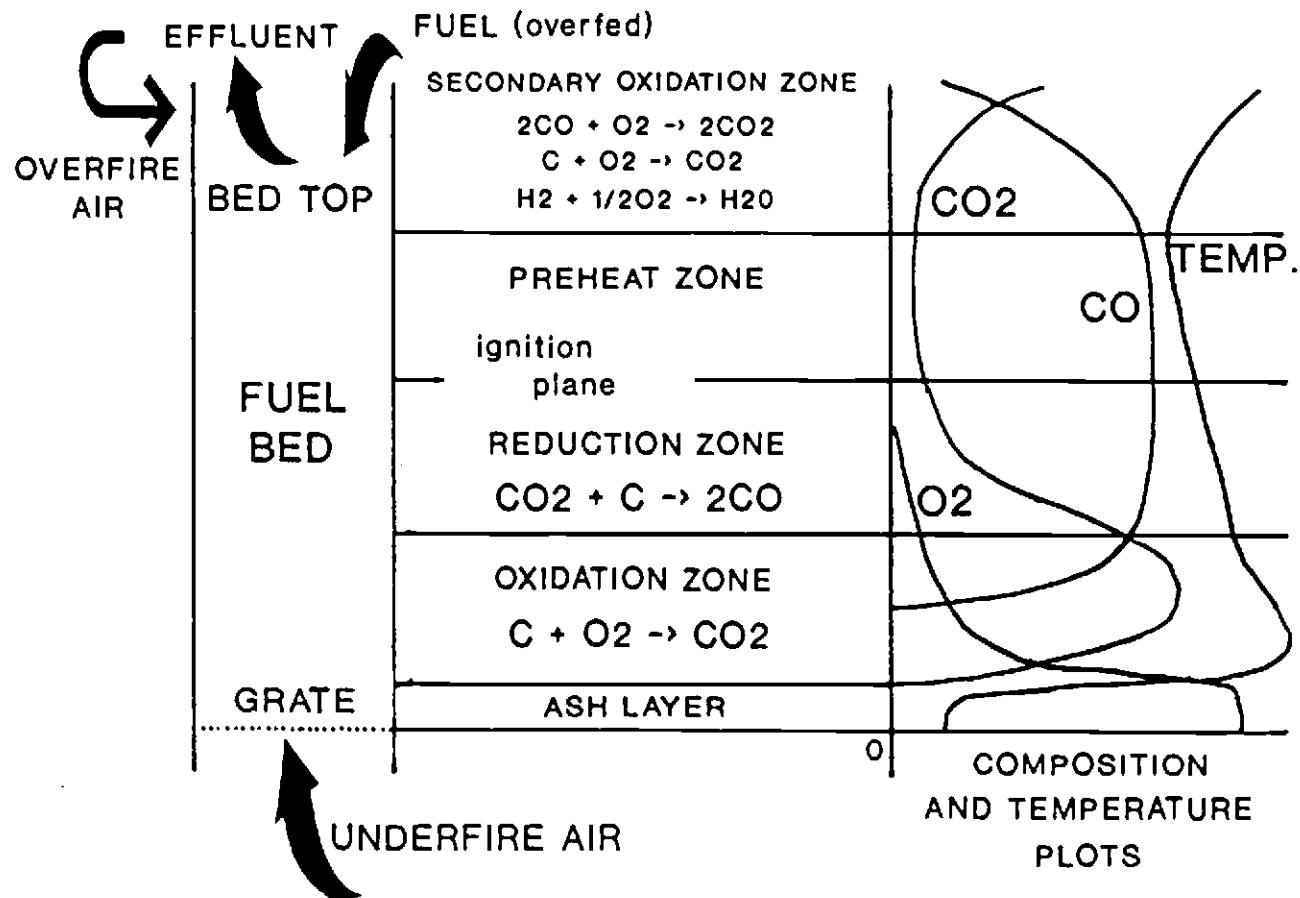
Figure 7.   Schematic Representation of a Fuel Bed and the Basic Chemical Equations for the Combustion of Solid Biomass Fuel, including Composition and Temperature Plots.   Source [6].

<u>Combustibles in Fly Ash</u>   -   Another widely used measure
of combustion efficiency is the combustible material
remaining in the ash that leaves the burner with the exhaust
gasses (called fly ash) [16].   This ash usually contains
inorganic (non-combustible) and organic (combustible)
particulate.   <u>If</u>, the combustion were 100 percent efficient
there would be no combustible in the fly ash, it would be
burned to CO_2 and/or H_2O.

<u>Oxides of Nitrogen</u>   -   Another indicator of combustion
efficiency that is not widely mentioned as such in the
literature are oxides of nitrogen.   The presence of oxides
of nitrogen (NO_x) in the exhaust gasses may prove to be a
useful indicator of combustion temperature.   Usually, NO_x is
discussed for its contributing role in photo-chemical smog
production, [6,11].   However, it is well known that NO_x
formation is catalyzed by increasing temperature, and as was
discussed earlier, increasing temperature signifies
increased combustion efficiency.

There is a complicating factor for solids combustion.
It is that NO_x can be formed in relatively substantial
quantities by both air-born and fuel-bound nitrogen.   In
well-mixed, flaming combustion NO_x should peak at the
stoichiometric air/fuel ratio, but because of "kinetic non-
equilibrium" effects it is found in a slightly oxygen rich
environment [11].   The NO_x formed by air-born nitrogen is
sometimes called "thermal NO_x" because its

formation is highly temperature dependent, but it also depends on local oxygen concentration.

Nitrogen in fuel is usually bound to hydrogen or carbon atoms and is sometimes called "chemical NO_x" when it is burned. Experiments have shown that when fuel nitrogen compounds are present the overall NO_x level can significantly increase. Most interesting though is that fuel bound NO_x formation seems to be only slightly temperature dependent as opposed to the strong temperature dependence of thermal NO_x formation [11]. Fortunately (from an air quality standpoint) fuel-bound nitrogen is usually a very small percentage by weight of the elemental components of biomass fuel, i.e. $\approx$ 0.0 - 1.0 %, see Table 1.

PROBLEM FUELS : EMISSIONS / ENVIRONMENTAL STANDARDS

<u>GASEOUS AND RELATED EMISSIONS</u> :

This section outlines the gaseous emissions and other pollutants that are currently regulated by Federal, State or local agencies. No attempt is made to cite exact emission standards for all possible situations. This is a very complex subject which depends on many factors, including:

1) Type of appliance

    a) residential wood stove

    b) commercial / institutional boilers

2) Size of appliance (heat or steam rating)

    a) Btu/hr

3) Fuel used

    a) coal, oil, natural gas

    b) cofired; coal + wood etc.

    C) RDF / MSW

4) Regulatory Agency

    a) area where appliance is situated

    b) time of year

    c) air quality at any particular time

Information on emission standards specific to a particular installation, can be obtained from the Environmental Protection Agency (EPA), Federal Register, or your State Environmental Agency. This discussion does not cover the pollution abatement equipment that controls these emission problems; that is another large topic by itself.

Emission regulations are enforced by three levels of government : Federal, State and local. The Federal agency in charge of setting standards and enforcing them is the Environmental Protection Agency (EPA). The EPA sets the standards for type of emission, sampling method and emission level. The State agencies (such as Oregons' Department of Environmental Quality DEQ), and local agencies, are really the workhorses in the program. Their job is to provide a permitting process and make sure the EPA standards are met or exceeded, i.e. each State has authority to raise the emission level standard above that required by the EPA, but they may not provide variance for lowering those standards.

Table 5, lists the EPA criteria and non-criteria emission species for wood fired appliances. "Criteria" species refers to emissions that are regulated by law and non-criteria species are those that are not regulated at present but are being studied extensively for possible inclusion.

Table 5. EPA Criteria and Non-Criteria Emission Species for Wood Burning Devices. Source [6].

Emission Species	Criteria	Non-Criteria
Particulate	*	
SOx	*	
NOx	*	
Hydrocarbons	*[a]	
CO	*	
Condensable Organics		*
POM[b]		*
Formaldehyde		*
Total Carbonyls		*
Phenol		*

[a] : Typically there is a Primary Ambient Air Quality Standard (PAAQS) set for all criteria emissions, however, none exists for hydrocarbons [6]. Some States do have a standard for hydrocarbons.

[b] : POM = Polycyclic Organic Matter

It should be noted that the above criteria emission species are enforced at some level for all combustion devices

including those that burn coal, oil, RDF and other biomass fuels. Following is a brief description of each criteria emission.

Particulate - This is the total matter in solid phase that exits the furnace stack. It consists of combustible, organic and non-combustible (ash) material. The standard for sampling particulate is EPA Method 5. In many instances this is the only emission requirement necessary to meet state certification. Along with particulate, many states have opacity standards which limit the amount of visible smoke emissions [15].

Sulphur Oxides (SO$_x$) - SO$_x$ is formed by oxidation of fuel bound sulphur during combustion. Sulphur content in wood fuel is usually so low that SO$_x$ is immeasurable, however, this may not be the case with RDF fuels or in coal + biomass cofiring applications. See Table 1, in "Solid Biomass Fuels" chapter. Applicable standard is EPA Method 6. Some work suggests that even in bark combustion with relatively high sulphur content most of the sulphur (approximately 95%) remains in the ash [24].

Nitrogen Oxides (NO$_x$) - NO$_x$ formation was discussed earlier in the chapter on "Combustion of Biomass Fuels". Most licensing agencies do not regulate NO$_x$ emissions. This is due to the fact that most local areas are not subject to the atmospheric conditions leading to photo-chemical smog. However, regulation seems eminent in areas such as

Los Angeles that do have smog problems occasionally.

It should be noted that there are no NO_x pollution abatement methods (no devices) that can be employed "on-line" in the exhaust stream. Only by reduction of flame temperature can NO_x formation be decreased [32]. Operating at low excess air levels, using low-turbulence diffusion flame operation and using water cooled furnaces also helps control NO_x formation.

Carbon Monoxide (CO) - CO formation is a result of poor combustion. It can be a serious problem in boilers fired with wet fuel because it is caused by low combustion temperatures, especially in the flaming combustion zone where much of the CO is converted to CO_2 in furnaces using overfire air (see Fig 7 in the "Combustion of Biomass Fuels" chapter). CO emission tests are not always required by regulatory agencies, but, it is much more widely tested then NO_x.

Hydrocarbons - Hydrocarbons are volatile gasses that result from the incomplete combustion of both the carbon and hydrogen in fuel. Usually they result from incomplete pyrolysis and combustion of large chain volatiles such as cellulose and formaldehyde [3]. Similar to carbon monoxide, hydrocarbon emissions are not usually a test requirement to meet state licensing laws.

Emission Standards for Contaminated RDF \ MSW Type Fuels :

The entire field of combustion technology and environmental standards for RDF \ MSW is in a rapidly, growing stage. The information in Table 6 is adapted from [37]. Table 6, shows the current National Ambient Air Quality Standards (NAAQS) for any device (including furnaces) which emit such pollutants.

Table 6. National Ambient Air Quality Standards.
Source [37].

Emission Species	Averaging Period	Primary Standard (mg/m^3)
Sulphur Dioxide	24 hr	365
Total Sus. Particulate	24 hr	260
Carbon Monoxide	8 hr	10,000
Photo-Chemical Oxidants	1 hr	240
Nitrogen Dioxide	Annual mean	100
Non-Methane Hydrocarbon	3 hr	160
Lead and its compounds	1 calendar quarter	1.5

In addition to the NAAQS, another set of standards called National Emission Standards for Hazardous Air Pollutants (NESHAP) comes from the Clean Air Act Amendment of 1977 (CAAA). NESHAP regulates emissions for which no NAAQS exists. At present the EPA has designated : asbestos, beryllium, mercury and vinyl chloride as hazardous air pollutants [37].

Other Pollutants - At this time, major institutions are studying the gaseous emissions of other pollutants. Presently there are no regulations concerning these pollutants. The pollutants include : Silver (Ag), Arsenic (As), Barium (Ba), Cadmiun (Cd), Chromium (Cr), Copper (Cu), Nickel (Ni), Antimony (Sb), Selenium (Se), Thallium (Tl), Zinc (Zn), Polyaromatic Hydrocarbons (PAH's), Polychlorinated Biphonyls (PCB's), Tetra-Chlorinated Furans ("Furans"), and, Tetra-Chlorinated Dioxins ("Dioxins") [1].

SOLID EMISSIONS (Bottom and Fly Ash) :

For solely wood-fired furnaces of institutional or commercial size there are no ash handling standards similar to the EPA regulations for gaseous emissions. Many wood product industry boilers in the five-state Northwest Region use the ash for roadfill. However, for coal, RDF, or MSW furnaces there are EPA standards. Many utility size boilers both coal, co-fired, or pure RDF/MSW fired, use water to

quench and transport collected grate and fly ash. Actually, water (many times it is done pneumatically) cannot be used anymore to transport flyash as can be seen in Table 7 on the following page.

Table 7. Typical Effluent Concentrations. Adapted from [32].

| SPECIES | POLLUTANTS | | |
	Oil and Grease	ph	TSS[a]
Bottom Ash	1mg/l x max.flow .75mg/l x avg.flow	6 - 9	5mg/l x max.flow 1.5mg/l x avg.flow
Flyash	0	6 - 9	0

[a] : TSS = Total suspended solids

Reference [32], states that where siting conditions permit, ash slurry is pumped to holding ponds where the process may include water recovery and reuse.

EP Toxicity - For RDF/MSW or cofired plants, the EPA requires that bottom ash be tested for the following heavy metals : See Table 8 on the next page.

Table 8. EP Toxicity Parameters and Current Maximum
Allowable Levels. Source [6].

Metal Contaminant	Max. Allowable Concentration (milligrams/milliliter)
1) Arsenic	5.0
2) Barium	100.0
3) Cadmium	1.0
4) Chromium	5.0
5) Lead	5.0
6) Mercury	.2
7) Selenium	1.0
8) Silver	5.0

The trace metals Antimony, Beryllium, Copper, Nickel,
Thallium, and Zinc, are also under intense scrutiny as
possible contaminants to add to the EP Toxicity list [1].

SUMMARY - A comprehensive document that would describe
the current laws could not be found. Anyone interested in
the current state of environmental regulation of biomass
fueled furnaces must be willing and able to specify all
physical variables of the source of interest and request all
current Federal, State, and possibly local or regional laws
and regulations as regards a particular application.

PROBLEM FUELS :   ASH

Ash from biomass fuels is the single most destructive constituent for furnaces and boilers. The following discussion will help illustrate why this is true.   First, let us consider the chemical make-up of some typical ash. Table 9, is a listing of the ASTM standard chemical compounds and their typical values for different fuels.   The ASTM standard is No. D-3174, "Test Method for Ash in the Analysis Sample of Coal and Coke From Coal".

Table 9.   Various Chemical Ash Analyses from Selected Literature.   Sources   [10,20,32]

ASTM Component	PERCENTAGE (dry-basis)		
	Coal (range)	Wood Pellets (avg.)	RDF (range)
SiO_2	10 - 70	36.0	7.1 - 14.6
Al_2O_3	8 - 38	3.5	2.3 - 7.6
Fe_2O_3	2 - 50	2.3	1.6 - 3.2
CaO	.5 - 30	42.0	5.5 - 8.3
MgO	.3 - 8	5.0	1.2 - 5.0
Na_2O	.1 - 8	.6	5.3 - 10.8
K_2O	.1 - 3	6.0	7.1 - 7.4
TiO_2	.4 - 3.5	.25	.6 - 1.1
SO_3	.1 - 30	3.0	29. - 33.5
P_2O_5	unavailable	3.0	1.0 - 1.46

The three main problems with ash in fuel are :

1)   **Slagging / Deposition**

2)   **Erosion**

3)   **Corrosion**

Ash, and the symptons mentioned above, are so problematic in pulverized coal steam generators that the management of coal ash is one of the major design considerations for such boilers [32].   Likewise, these problems can be just as bad in poorly designed home heating units.

1)   SLAGGING / DEPOSITION   :

Slagging occurs when ash becomes softened or liquid and clings tenaciously to grate, ceramic and waterwall surfaces. "Slagging" is a term that is widely misused to describe two distinct entities.   These entities are - **Slagging** : fused matter or re-solidified molten ash that forms on furnace walls or other surfaces exposed mainly to radient heat or very high gas temperatures.   **Deposition** : Cemented or sintered ash build up usually on convection surfaces like superheater and re-heater tubes, but also on cooler furnace surfaces.

Many parameters have been used to evaluate ash behavior as they affect slagging and deposition. Some of these are :

- ash fusibility   - silica / alumina ratio

- base / acid ratio   - dolomite percentage

- iron / calcium ratio   - ferric percentage

- iron / dolomite ratio

It is beyound the scope of this text to describe all these parameters. However, ash fusion or fusibility temperature (which is considered to be the most critical) will be discused.

Four temperatures are currently used to specify ash fusion temperature as specified by standards such as ASTM No. D-1857, " Fusibility of Coal Ash". The exact definition of these temperatures is not given here, but their names are the following :

a) Initial Deformation Temperature (IT)

b) Softening Temperature (ST)

c) Hemispherical Temperature (HT)

d) Fluid Temperature (FT)

These definitions refer to the shape of a specified cone of ash as it is subjected to increasing temperature under

"standard" conditions. This test can be performed in an oxidizing and/or reducing environment. This is important depending on which environment the ash will be in. Furnaces operated at low excess air level or with poor mixing would create local reducing environments. Table 10 below, gives the ash fusion (fluid) temperatures for a number of species in oxidizing and reducing environments.

Table 10. Ash Fusion Temperatures for Selected Species of Biomass Fuels. Sources [10,20,32].

Species	Ash Fusion Temperature (fluid)	
	Oxidizing (°F)	Reducing (°F)
ASTM Rank hvA coal	Unav.	2660
ASTM Rank subbit.C	Unav.	2310
RDF (range)	2200 - 2420	2160 - 2340
wood (avg)	2390[a]	2410

[a] : Results from OSU's study on selected wood fuels.

It is apparent that ash fusion temperature (fluid) is not really too different for the fuels considered in Table 10. It is not shown, but there is even less difference between the four stages within a group, i.e. the IT, ST, HT, and FT measurements.

Major Problems with Slagging and Deposition -

A)   Reduces heat transfer on heat exchange surfaces.

B)   Can bridge, plug and mechanically destroy grates.
The reduction or redistribution of under fire air from
plugged grate holes is very undersirable for
combustion.   It adversely affects efficiency and
emissions.

C)   Can actually tear down refractory by repeated
liquidizing and re-solidification.

D)   Requires monitary and time expenditure for cleaning
 by both mechanical and human intervention.

2)   EROSION :

Erosion of furnace and boiler surfaces is largely due
to dense, hard, particulate ash which is in the gas stream.
It is a very important topic because erosion can be rapid if
the right conditions exist of high ash concentration and
high exhaust velocities. Literature such as, [16], have
reported on the mean fly ash particle size and density for
various firing conditions of pelletized Douglas Fir Bark.
Data such as this could be very useful in quantifying rates
of erosion vs. density or particle size.

3) <u>CORROSION</u> :

Corrosion has been studied intensively by the coal furnace and boiler industry. It is also gaining rapid attention in the cofiring and RDF / MSW industry because of the highly corrosive nature of the constituents in RDF and MSW [26]. The major problem with corrosion is metal wastage. Below, is a list of conclusions on corrosion from commercial coal-fired unit experience (adapted from [32]).

a) Only a small percentage of coal fired units experience serious corrosion requiring major operating corrections.

b) For coals that are "corrosive", metal temperature plays a signifigant part in the corrosion rates.

c) Molten ash from corrosive coal is highly aggresive and corrosion is not easily preventable.

d) All cost-viable boiler materials are inadequate if the coal is corrosive.

e) Various tube coatings have been tried but all seem cost prohibitive and or the raw metals are in short supply.

Chloride as a Corrosion Factor - For salt-soaked wood
fuel and RDF/MSW chlorine can cause severe metal wastage.
Chlorine in refuse is responsible for the most serious
corrosion of boiler tubes [41]. Sulfur, Sodium, potassium,
lead and zinc also do their share.

A very extensive study of chloride corrosion from the
burning of both RDF and MSW cofired with high sulphur coal
was documented in [41]. The tests were condudted at the
Municipal Electric Plant, Columbus, OH. The following
conclusions have been drawn from [41] :

A) The conversion of chlorides to sulfates in ash

deposits by the action of SO_2 releases chlorine and

hydrochloric acid at the metal surfaces. This causes

serious corrosion.

B) Chloride corrosion can be made negligible by

increasing the available sulfur in fuel to equal

2% by weight of the refuse.

C) Cofiring of MSW with high sulphur coal for up to a

60/40 blend (Btu basis) will not increase the initial

corrosion rate beyound that of coal alone.

Points B and C above are fascinating and potentially very
valuable. There are two major benefits to cofiring high
sulfur coal, MSW/RDF, or salt soaked wood biomass. One
benefit is that decreased high-sulfur coal input means less

sulphur oxide emissions and subsequently less acid gas emission, i.e. H_2SO_4, one component of "acid-rain". The other benefit is that metal wastage by chloride corrosion is reduced signifigantly, helping reduce maintenance and material cost.

Fig. 8 shows the isothermal corrosion rate in (mils/hour) vs. sulphur addition to refuse (MSW). It was adapted from [37].
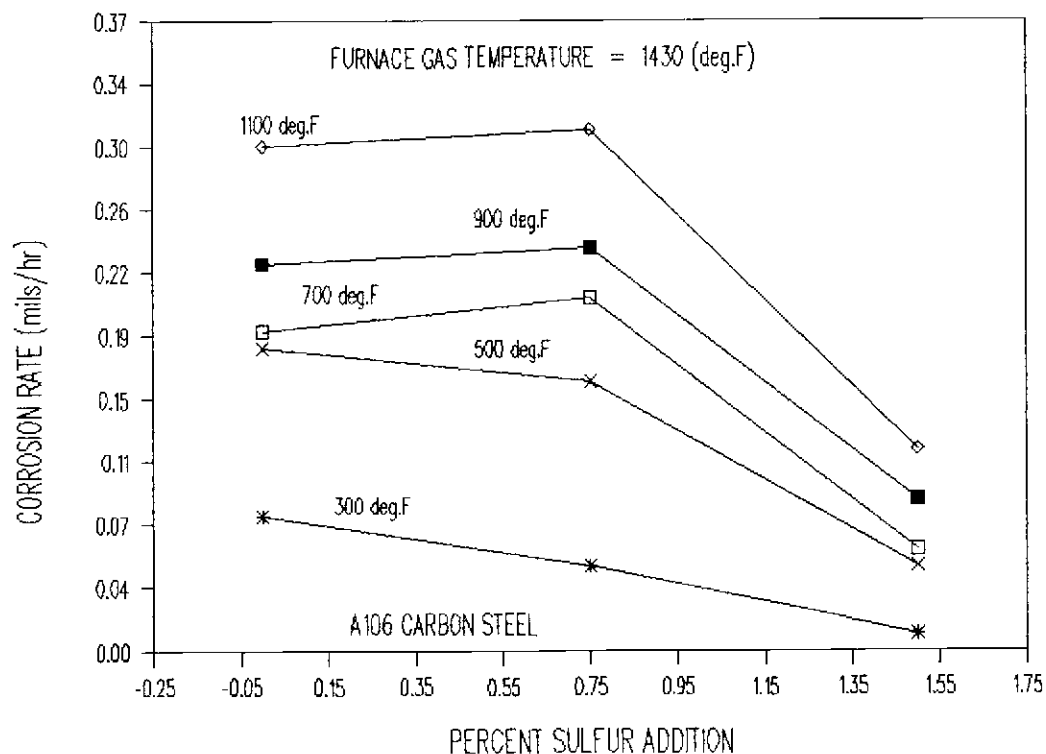
Figure 8. Isothermal Corrosion Rates as a Function of Sulfur Addition to Municipal Solid Waste. Source [41].

Figure 8, shows that for sulphur additions less than .75% the result is generally increased corrosion, yet, beyond .75% there is a dramatic corrosion reduction.

The gaseous emissions were not included in this study, so a judgement can not be made of the relative merit of corrosion inhibition vs. emission quality. The overall idea

seems very worthwhile and more studies should be done.

As a last comment on corrosion problems for refuse type fuels, a study was conducted concerning the influence of lead (Pb) and zinc (Zn) on corrosion in refuse-fired steam power plants [20]. The final conclusion was that lead and zinc in the form of chlorides of lead sulphates and chlorides of zinc, contribute to the corrosion in said power plants.

Final Remarks on Ash - It should be apparent now that ash is a very destructive element in operating furnaces and boilers and may also be a toxic or harmful environmental disposal problem. Wood fuels, in general, will cause much fewer problems because of their low ash content, low heavy metal and usually low chloride concentrations. MSW/RDF fuels can cause signifigant problems due to their overall ash content and chemical nature.

COFIRING

Cofiring is generally considered to be the combustion of biomass with coal, but it may also be the concurrent firing of two dissimilar biomass fuels such as wood and RDF. Currently published cofiring experience is limited to large scale steam and electric plants. The reason for this is that electric utilities have been studying and using biomass as a real supplement to their normal coal fuel since the early 1970's. The attractiveness of biomass as a utility fuel is a function of the price of fossil fuels, the technology base(especially for retro-fitting), and system economics. The following sections draw heavily from work carried out by a number of private research and engineering firms, sponsored by the Electric Power Research Institute (EPRI). Necessarily, most of their discussion is for large scale (5-50 MW) power plants, but most of the findings are relevant to cofiring on a smaller scale. Two main sections follow, one is on the positive aspects of utilizing biomass for cofiring and the other section discusses the negative aspects as they have been determined by utility experience.

POSITIVE ASPECTS OF COFIRING :

One of the best reasons for utilizing biomass is the

price compared to fossil fuels, also, the price of most

biomass fuels has not increased as rapidly as fossil fuels

[9]. However, there is not sufficient availability in most

localities to completely supply large utilities and that is

why cofiring is the issue here.

Although there does not seem to be an eminent danger of

a shortfall in primary energy, i.e. coal, nuclear, and oil,

it is a possibility and another motivation for at least

studying cofiring. Conversely, in many areas of the U.S.

there is a windfall of biomass, so much in fact that it is a

real disposal problem. For example, Portland, Oregon, has

recently had to perform some rapid economic, societal, and

sometimes painful political planning to determine what to do

when their current landfill becomes inoperable. Their final

decision is to truck their waste outside of the Portland

Metro area to a new landfill. Whole geographic areas may be

afflicted, such as Southeast Alaska, where both MSW and wood

biomass pose real disposal problems. The two main reasons

for this are the fact that most of Southeast Alaska is

public land, and, the areas that are private are unsuitable

for landfilling (it is hard rock). The State of Alaska

also maintains emission standards that exceed the Federal

requirements in some cases.

A major reason for using biomass is to ameliorate the

impact of strict environmental regulations. Biomass can

help because it has shown to be cleaner in use than some

fossil fuels [9]. One major problem in burning coal is its sulphur content. Coal sulphur content ranges from .5 to 5 percent by weight, and generally, 90 percent or more of this will be converted to sulphur oxide pollutants. These pollutants are primarily sulphur dioxide SO_2, with one to four percent sulphur trioxide SO_3 [32]. Wood and RDF have sulphur contents that range from 0.0 to .1, and, .1 to .6 percents respectively [13,32]. Obviously, the use of wood and/or RDF as additives to coal will decrease the overall output of sulphur oxides on a per Btu fired basis.

The production of biomass may also be less destructive to the environment, i.e. mill residues, tree and seed farms, and RDF processing plants, VS. strip mining, nuclear waste disposal, and the catastrophic dangers of pipe line or tanker rupture (as recently occurred in Prince William Sound, Alaska).

The presence of biomass processors in a local area that can act cooperatively is a site-specific advantage for cofiring [9]. A study was completed of cofiring wood chips with coal in interior Alaska [28]. An interesting problem was noted for interior Alaska; they would like to clear more land for agriculture and thin many stands of existing timber, but it is not economically advantageous at present. Currently, the practice is to pile and burn the biomass but this is expensive since it requires repeat piling and burning up to four times to sufficiently reduce the volume

[28]. A complete technological and economic study was completed for Fort Wainwright, Alaska, to assess the feasibility of using wood biomass with coal to produce steam. The Fort Wainwright tests led to the following technical and economic conclusions respectively.

Technical Feasibility -

Burning wood chips with coal for producing steam is technologically feasible. The major problems were in fuel handling prior to burning and in meeting peak demand. One problem was mixing, but through trial-and-error the Fort Wainwright group found a suitable solution. Another problem was inadequate chip hopper volume and freezing. Both of these problems could be dealt with by a minor investment in storage technology.

The last major problem was meeting peak steam load. The stoker at Fort Wainwright was incapable of feeding enough fuel above an 80% coal + 20% chip mixture to keep steam rates at desired levels. This was mainly associated with the Fort Wainwright boiler and could be eliminated with a high volume stoking system [28]. Very desirable facets of the operation were emissions all well below the State of Alaska Standard of .1 grams per dry standard cubic foot for coal burning installations operating before July 1, 1972. There was also an eight to sixteen percent reduction in

bottom ash.

Economic Feasibility -

As long as delivered wood chip moisture content is below 45% wet-basis (and all chips during testing were less than 41.6% moisture), all harvesting scenarios considered would result in a cost less than coal per Btu. However, the harvesting scenarios all assumed annual production of more than 20,000 tons of chips. With diminished output the harvesting would become economically infeasible. Unfortunately, the Fort Wainwright plant could, at best, only use approximately 50% of this 20,000 tons of chips. One or more utilities using wood chips would solve this problem.

In conclusion, the Fort Wainwright study showed promise as a consummate match of community need and biomass use. There were problems but these are expected in any experimental, retro-fitted design.

Another positive aspect of cofiring is in high "load growth" areas, where rapid industrial and/or residential growth demands more energy. This growth will necessitate the building of new electricity generating equipment. Biomass based cofiring installations may be desirable in areas with large local biomass supplies. One particular advantage is that cofiring installations are not as

sensitive to economies of scale such as in the nuclear industry where it is infeasible to build "small" plants because of the investments in environmental studies, safety and security engineering.

Table 11, contains economic data and motivational reasons for cofiring in actual situations.

Table 11. The Economics of Cofiring at Several Commercial Boiler Sites. Source [9].

Cofiring[a] Plant	Species Type	Purchase Basis	Fuel Cost[a] bio.	other	Motivation	
1	hardwood wastes	Btu	.6	coal 1.5	fav. economic comm. interest	
2	hardwood wastes	Btu	.6	oil 5.0	fav. economic comm. interest	
3	softwood sawdust	wt.	1.0	coal 1.2	marg. economic	
4	Softwood Aspen	wt.	.7	coal 1.7	fav. economic comm. interest	
5	Contaminated Seed Corn	NA	NA	NA	fav. economic disposal prob.	

[a] : Plant 1) Northern States Power, Red Wing, Minnesota.
Plant 2) Northern States Power, French Island, Wisconsin.
Plant 3) Grandhaven Board of Light and Power, Michigan.
Plant 4) Lake Superior District Power Co.
Plant 5) Cedar Falls Utilities.

[a] : cost figures are dollars per million Btu and not corrected for inflation.

Table 11, demonstrates considerable promise for cofiring wood wastes with coal and even oil. In fact, there is very little evidence of technical reasons against cofiring wood, and the economics look good for site-specific installations.

The following discussion covers some literature on the positive aspects of cofiring RDF fuel with coal in utility boilers.

Madison Gas and Electric Co. (MGE), Blount Station (BS), Madison, WI.

Blount Station has been burning RDF on a small but continuing scale since 1979. BS burned 13,816 tons of RDF in 1894, and MGE declares that the performance of the fuel has been satisfactory [26]. BS has experienced no technical boiler problems not attributable to normal wear. In fact, stack emissions tests indicate that particulate emissions were not increased while cofiring and hydrochloric acid (HCL) emissions were no greater than they would be while burning a typical Midwest coal.

Despite the rosy technical picture, MGE has not been able to operate the BS plant for a profit. It should be mentioned that it continues operation because of support from the public sector, i.e. the City of Madison is intimately involved in the project. The primary reason for operating at a loss is given as the inability to burn 20,000 tons per year of RDF as originally planned. Unfortunately,

the author does not say _why_ the 20,000 tons is not being burned.

Department of Electric and Water Utilities (DEWD), Mcintosh Power Plant (MPP), City of Lakeland, FL. The MPP facility processes and burns an average of 150 tons of raw MSW per day. The "processing" is a complete MSW-to-RDF plant. In fact, the MPP is the largest refuse-to-energy electric generating station in the U.S. [26]. The MSW-to-RDF processing facility is specifically designed to provide a supplemental fuel (10%) for the MPP boilers. It currently produces a revenue of $30,000 per month.

Below, is a listing of the technical aspects of this operation in regards to RDF problems or lack thereof.

Ash - The RDF has three to four times as much ash as the coal being burned, but since the unit was designed with this in mind there have been no problems.

Slagging - No additional problems.

Boiler Efficiency - Efficiency is reduced due to high moisture content (38%) and cold air introduced by the RDF pneumatic conveying system. However, it is noted that SO_2 emissions are down.

Boiler Corrosion - Tests have shown that RDF burning could be doubled before significant corrosion occurs.

Technically, the operation sounds quite efficient now, however, it took two years to identify and correct the initial processing and burning problems. Despite this long "learning curve" the DEWD predicts the benefits both environmental and economic to be gained during the lifetime of the plant show solid waste disposal and power generation are profitable and compatible. The DEWD believes the benefits of reducing coal use and slowing landfill expansion should offset the cost of retro-fitting existing plants, or building new ones. This seems especially true if valuable information such as that given in the DEWD report is made available, i.e. if we learn from others trials.

There are three other RDF cofiring utility experience papers given in [26], and much more information on actual cofiring experience. It is highly recommended reading for anyone interested in this topic.

The preceding discussion shows that cofiring woody or RDF biomass with coal (or oil) is technically feasible and economically beneficial in many circumstances. However, there are serious technological problems that have been experienced while cofiring RDF in particular. The next section describes these problems.

NEGATIVE ASPECTS OF COFIRING :

Ash -

There are problems associated with both the quantity and quality of RDF ash. Extreme values of ash content from 4.3 to 53.8! percent by dry weight are reported in literature [13]. Secondly, typical ash fusion temperatures are lower for RDF than coal in an oxidizing environment and nearly the same in a reducing environment [26]. This means that RDF ash has a greater potential to soften and stick to boiler surfaces and reduce heat transfer capability. "High" heat release boilers should be avoided for cofiring RDF [26]. Glass and aluminum can cause severe slagging problems if major quantities are not screened out.

Material Handling -

There have been five problem areas in the past, as listed below :

1) Dust along transport lines and in receiving stations.

2) RDF compaction and odors in storage bins due to long storage times.

3) Inconsistent RDF fuel reclaim flow due to bridging and corrosion.

4) Oversized materials, textiles, and wire plugging air lock feeder and/or transport lines.

5) Variation in RDF heat input to the boiler due to volumetric feed systems and inconsistent RDF heating value.

Boiler Efficiency -

Detailed computer simulations have shown that a typical 200MW boiler will see a 1.9 to 4.2 percent decrease in efficiency at 20% RDF firing (heat input basis) [12]. There are two main reasons for this, 1) increased flue gas exit temperature, 2) increased flue gas flowrate.

Increased flue gas flowrate is caused by higher excess combustion air necessary for proper firing of RDF. The reason for this is probably because of the high moisture content, i.e. more air is needed for drying, although reference [12] did not specify exactly why more excess air was needed. Increased flowrate is also due to higher fuel mass flowrates to achieve the same Btu output as coal, and higher moisture content.

Increased flue gas exit temperature is due to the higher excess air requirements, and, in many installations the preheat section (using exhaust gas) does not heat the RDF combustion air used for pneumatic transport [12]. Decreased heat transfer due to slagging can also increase flue gas temperature.

The results of 1) and 2) above is to incur boiler losses due to dry gas heat loss, water vapor heat loss, and unburned combustibles (carried out by increased volumetric flowrates).

Furnace Metal Wastage -

Steam generator manufacturers recommend maximum RDF
cofiring rates of 20% of the total fuel heat input to insure
HCl concentrations in the combustion gas are low enough to
avoid increased corrosion on metal boiler surfaces [12].
The primary problem seems to be when bottom ash piles up
onto water wall tubes, especially in tangentially fired
units. Low oxygen levels and a reducing atmosphere next to
the tubes catalyzes tube wastage due to RDF contact.
Fortunately, no increased corrosion of superheater tube
surfaces has been reported.

Emissions / Pollutants -

Currently, RDF cofiring plants have had little
difficulty meeting Federal or State air quality standards.
This may change rapidly however as there is current work on
developing rigorous standards for a host of "new" pollutants
including : acid gasses(H_2SO_4, HCl, SO_2, HF, NH_3), heavy
metal particulate, including (Pb, Zn, Cr, Sn,..), and,
trace organic compounds such as dioxin and furan [26]. The
literature is quite inconclusive at this point, but further
reference to this topic was made in the previous report
section titled, "Problem Fuels : Emissions / Environmental
Standards".

CHAPTER II

PELLET FUEL SPECIFICATIONS AND

COMBUSTION EXPERIMENTS

FUEL SPECIFICATIONS

One of the objectives of this thesis was to test wood pellet fuels for a range of pertinent variables and to report the results of these experiments. This data represents an expected range for wood pellet fuels from the Five State Northwest Region. The data would also be useful for anyone interested in comparing fuel values and/or designing handling and combustion equipment. Table 12, contains the codes for the pellet fuels tested as they will be referred to in the remaining text and Appendices.

The following dual code scheme is listed so that this document may be used as a reference in conjunction with other work being done at OSU on the same biomass pellet project. The codes on the left were used by the researchers for all phases of the work (this thesis does not cover all work performed during the biomass fuel characterization project).

Table 12. Pellet Sample Coding Used in this Thesis
and for Other Work Performed at OSU.

OSU Code Name	THESIS Code
BCCPP824-1AB*	1
FHLDF624-1AB	2
FHLDF624-2AB	3
PHCHF706-2AB	4
EVCMX713-1AB	5
WSPCD715-1AB	6
KMPMX727-2AB	7
SPCDF727-1AB	8
WFPMX920-1AB	9
PHCMX706-1	10
HSIMX824-1	11
BTPMX920-1	12
WDMMX920-1	13
RMMMX920-1	14

* : A => Pellets were analyzed for Proximate, Ultimate
Analysis, and Ash Fusion Temperature.

B => Pellets were burned for the experimental data
analyzed in this thesis.

If an "A" or "B" is not present, this means that the
pellets were analyzed for a subset of the variables
included in this report.

The variables of interest were the following :

CHEMICAL VARIABLES :

Ultimate Analysis :

     1) % Carbon
     2) % Hydrogen
     3) % Nitrogen
     4) % Sulfur
     5) % Oxygen
     6) % Chlorine

Proximate Analysis :

     1) % Volatile
     2) % Fixed Carbon
     3) % Ash

Ash Fusion Temperature(s) :

     1) Initial
     2) Softening or H/W
     3) Hemispherical or 1/2H/W
     4) Fluid

PHYSICAL VARIABLES :

     1) Higher heating value
     2) Moisture content
     3) Bulk density
     4) Specific density
     5) Mean length
     6) Mean diameter

85

RESULTS :

All pellet fuels were tested for their "Physical Variables" (as listed previously), but only nine of the fourteen total pellet species were tested for their "Chemical Variables". A complete report on each fuel (by code number) is found in Appendix C.

Table 13, is a compilation of ultimate analysis data including the, minimum (MIN), maximum (MAX), mean, and standard deviation (SDEV).

Table 13. Ultimate Analyses for Pellets Coded (1-9).

	all data are on a (dry-basis)					
	%C	%H$_2$	%N$_2$	%S	%O$_2$	%Cl
MIN	50.35	5.82	.10	.01	37.11	.00
MAX	54.16	6.35	.37	.30	42.54	.41
MEAN	51.77	6.09	.21	.05	40.41	.28
SDEV	2.53	.17	.10	.08	1.75	.33

It is evident from Table 13, that the elemental composition for these pellet fuels is not too different. The main differences are in chlorine and sulfur, but these

are at very small percentages relative to the other constituents. However, it has been stated earlier that chlorine, even in small percentages, can be very corrosive and also increases stack opacity and particulate loading.

Table 14, shows the summary statistics for the proximate analysis of the wood pellet fuels.

Table 14. Proximate Analyses for Pellet
Fuels (1-9).

	all data are on a (dry-basis)		
	% Volatile	% Fixed Carbon	% Ash
MIN	71.60	15.66	.21
MAX	84.13	25.85	2.74
MEAN	77.56	21.03	1.41
SDEV	4.20	3.29	.94

There is more variability in the proximate analysis data than the ultimate analysis data. This is due to the chemical structure of the elemental components not the relative percentages of these elements.

Table 15, lists the range of ash fusion data for the pellet samples.

Table 15.   Ash Fusion Data for Fuels (1-9).

	all data are on a (dry-basis) ASH FUSION TEMPERATURE (oxidizing, °F)[a]			
	Initial	Softening	Hemispherical	Fluid
MIN	2150	2160	2170	2195
MAX	2500	2530	2540	2550
MEAN	2340	2352	2363	2381
SDEV	136	137	138	141

[a] : The various ash fusion temperatures (Initial, Fluid, etc.) refer to the increasing "flatness" of a specified cone of ash as it experiences increasing temperature. "Initial" is least deformed and "Fluid" is when the ash appears molten.

It is interesting to note that the mean initial ash fusion temperature is only 1.7 percent smaller than the mean fluid temperature. Also, the global average difference between MIN and MAX values is only 361°F, not a significant amount considering the temperature variations associated with combustion in a furnace.

Table 16, displays the remaining (Physical) variables that were measured for all fourteen pellet samples.

Table 16. Physical Pellet Analyses Data for
Pellets (1-14).

	all variables measured (as-is) except for higher heating value measured (dry-basis)					
	HHV[a] (Btu/lbm)	MC[b] (%)	BLKD[c] (lbm/ft$_3$)	SPD[d] (lbm/ft$_3$)	Length (in.)	Diameter (in.)
MIN	8637.99	3.40	37.21	75.32	.266	.256
MAX	9284.34	14.40	53.34	83.92	.705	.317
MEAN	8721.26	6.98	41.84	81.26	.464	.287
SDEV	793.65	1.81	11.83	4.04	.174	.078

[a] : HHV = Higher heating value
[b] : MC   = Moisture Content (wet-basis)
[c] : BLKD = Bulk Density
[d] : SPD   = Specific Density

Some trends are immediately obvious from the data in

Table 16. One can see that bulk density appears more

variable than specific density, in fact the percent standard

deviation (SDEV/MEAN x 100), for specific density is 4.97

whereas for bulk density it is 28.27. The fact that

specific density is so uniform is amazing considering that

each pellet is a different specie and many are made by

different processes. The percent standard deviation for

higher heating value is only 9.10, which shows there is not

a considerable difference in these pellet fuels heating

value.

EXPERIMENTAL COMBUSTION OF
WOOD BIOMASS PELLETS

INTRODUCTION :

The Department of Mechanical Engineering at Oregon
State University has built a device to burn pelletized
biomass fuels. The device is named the Biomass Combustion
Unit or (BCU) in this report. The BCU was designed to aid
in the thermodynamic analysis of pellet fuel combustion.
This was accomplished by having appropriately placed
flowmeters, pressure gages, thermocouples and a gas analysis
unit with mobile probes. A complete description of the BCU
and accompanying equipment is in the next section titled,
"Experimental Apparatus".

The BCU was used to analyze nine different pellet fuels
under varying conditions of percent excess air (EA%), fuel
flowrate, and percent under fire air (UF%). EA% is the
volumetric quantity (percent) of air above that required for
stoichiometric combustion of the fuel. UF% is the
percentage of the total quantity of air fed to the
combustion chamber that is delivered from below the fuel
pile. For the BCU, the fuel pile was setting on a grate.
The air delivered above the fuel enters the BCU by a
perforated stainless steel tube four inches above the grate.

The air delivered this way is called the over fire air (OF).
Note that the percent over fire air (OF%) is simply 100
minus UF%.

Three separate tests were performed with the BCU, they
are :

1)   Determine the optimal EA% and UF% for one fuel.
Optimal refers to the most thermodynamically
complete combustion, i.e. combustion that is 100%
efficient by the First Law of Thermodynamics.

2)   Test the characteristics and efficiency of multiple
fuels over a range of feed rates and excess air(EA%)
holding UF% constant.

3)   Test multiple fuels for the effect of increasing
the under fire air temperature to approximately 300°F.

The following information explains the apparatus,
methodology, and results of using the Biomass Combustion
Unit (BCU) to perform the three experiments as outlined
above.

APPARATUS :

There are four figures following this page. Figures 9 and 10 are detailed drawings of the Biomass Combustion Unit (BCU). Fig. 11, is a schematic of the entire experimental facility and Fig. 12 is a detailed drawing of the X-Y Table and gas analysis sensing probes (probes).

Fig. 9, is a cutaway view of the BCU. It shows where under and over fire air enter below and above the grate respectively. In the upper-right corner is the feed tube where wood biomass pellet fuel enters the BCU via a metering drum (Appendix E) and horizontal auger. The fuel then drops by gravity onto the grate. The "cooling water feedtube" shown wrapped around the feed system, is there to prevent overheating of the auger system and pre-combustion of the pellets. In the upper-left corner of Fig. 9 is the port where combustion gasses exit the BCU and continue to other test equipment (see Fig. 11) and eventually are exhausted to the atmosphere. A detailed drawing of the fuel hopper and feed system is in Appendix E.

To prevent damage to the stainless steel outer shell of the BCU and to promote thermal stability, the BCU is lined with three inches of high temperature ceramic refractory. Fig. 10, shows this refractory casing in a "stand alone" fashion.
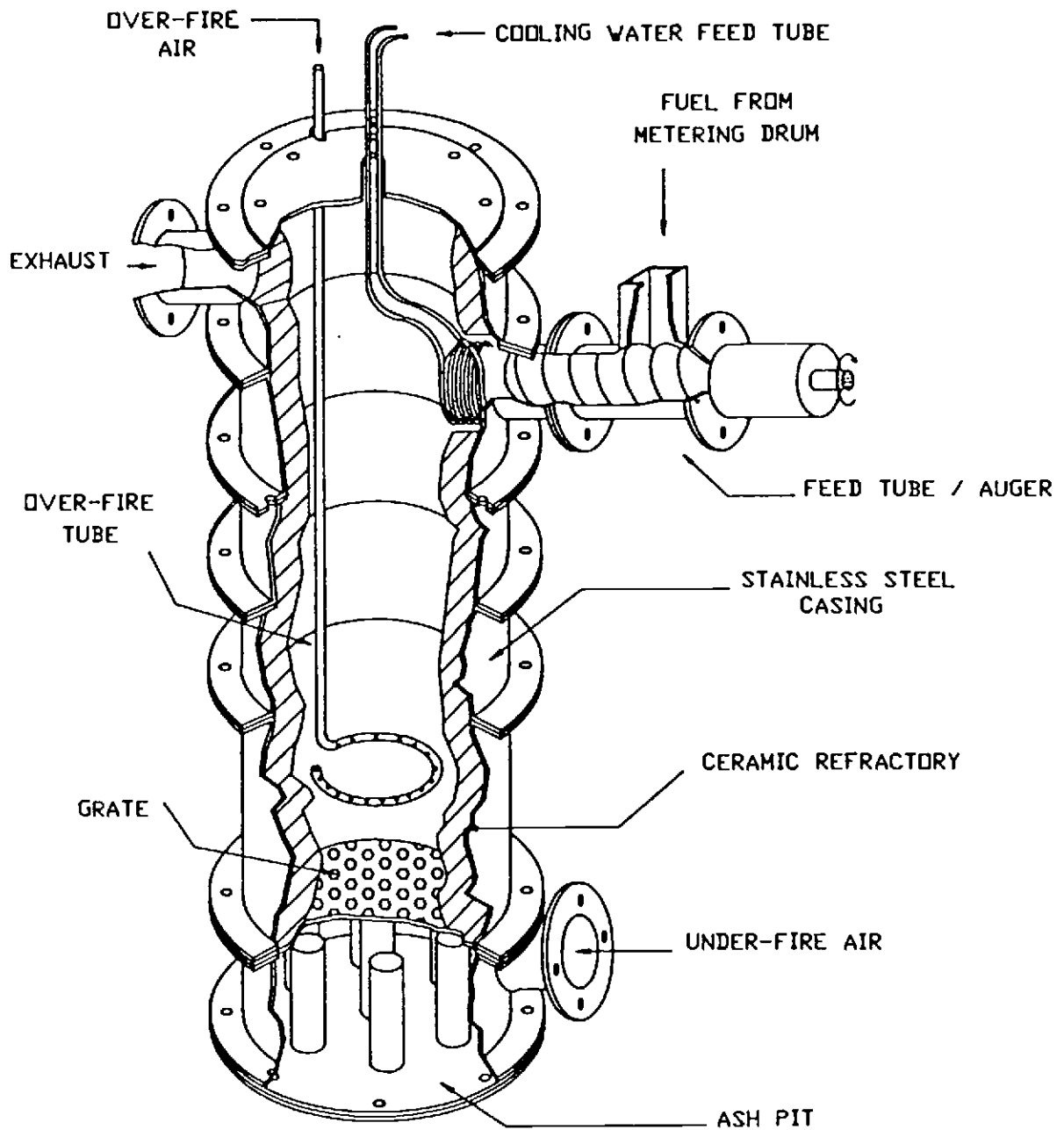
Figure 9. Cutaway View of the Biomass Combustion Unit (BCU). Shows Important Components Including : Over Fire Air Tube, Under Fire Air Port, Grate, Ceramic Refractory, Exhaust Port, and Pellet Fuel Feed Mechanism.
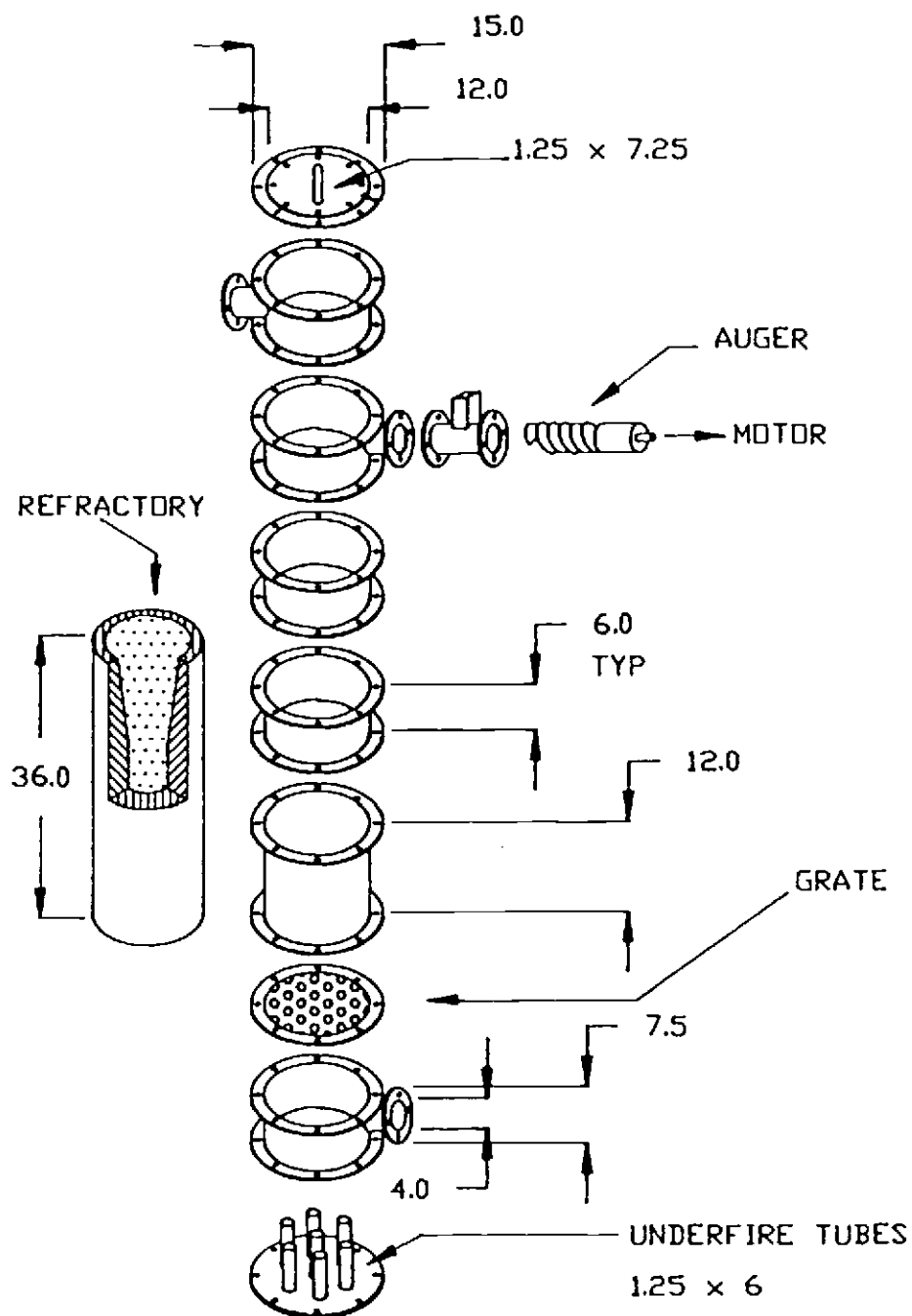
Figure 10. Scale Drawing (dimensions are in INCHES) of the Biomass Combustion Unit (BCU), Showing Individual Components Including the Cylindrical Refractory Insert.
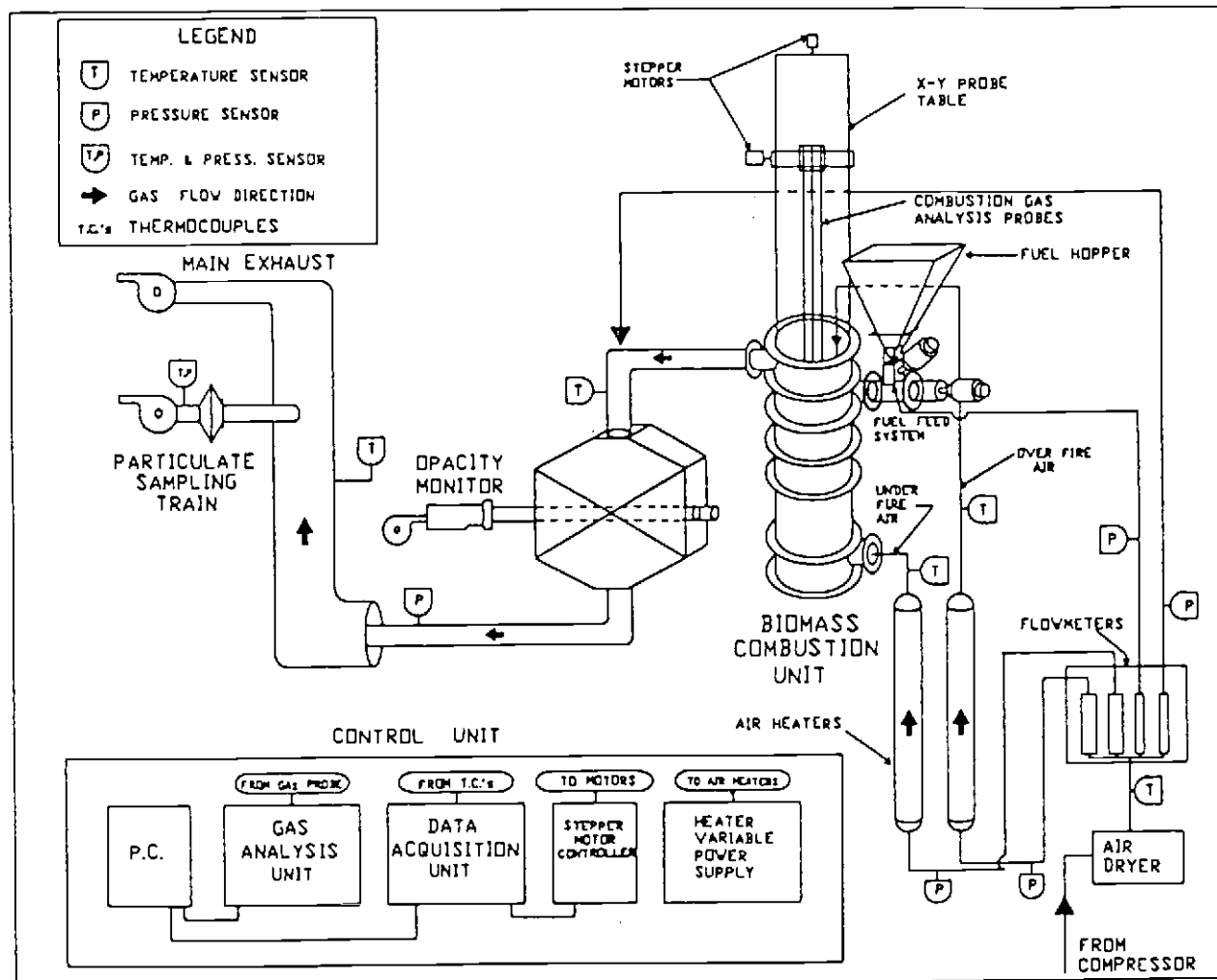
Figure 11. Schematic of the Entire Experimental
Facility. Shows Flows of Inlet Air, Pellet Fuel and
Exhaust Gases.

GAS ANALYSIS PROBE
(HOLDING FIXTURE)

SYNCHRONOUS
STEPPING
MOTOR
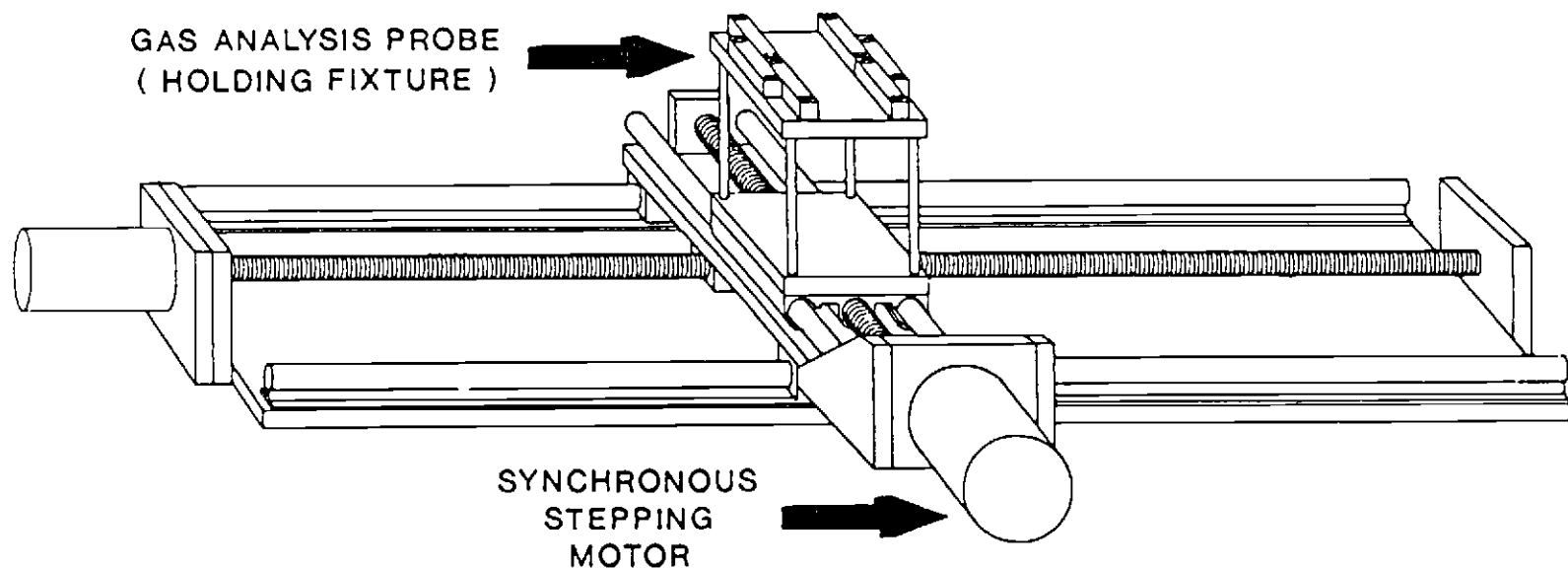
Figure 12. Schematic Representation of the X-Y Probe
Table. Showing the Synchronous Stepping Motors that
are Micro-computer Controlled and the Fixture which
holds the Gas Analysis Probes (probes not shown).

At the top of Fig. 10, is the BCU cover plate. This is
very important because there is a rectangular groove cut
through the plate that allows the temperature and gas
analysis probes (discussed shortly) to move both
vertically and horizontally within the combustion chamber.

Fig. 11, is an overall schematic of the system.
Following is a description (by name in quotes as they
appear in Fig. 11) of the major components.

AIR FLOW   -

All combustion air is delivered by an electric
compressor (not shown). The air then flows through a
dessicant+cotton-fiber filter (not shown) and then into
the "Air Dryer". The air dryer removes moisture and oil
found in the "raw" airstream. It performs this task by
condensation. Removal of moisture helps eliminate another
combustion parameter, i.e. air bound moisture is considered
negligible. Next, the air is metered to various
destinations by four rotometers or "Flowmeters". The
destinations for the air are the following :

1) air heater then to under fire port

2) air heater then to over fire port

3) fuel.feed port (not used in this experiment)

4) cooling port for "Opacity Monitor"

Once the UF and OF air is used for combustion and passes
through the BCU, it goes to the "Opacity Monitor" where a
measure of the exhausts opacity is made. Opacity, is the
propensity for the exhaust to diminish light travel, i.e.
the greater the opacity the more "smokey" is the exhaust.
It is measured on a scale from one to one hundred percent.
Finally the spent combustion gasses are drawn into the "Main
Exhaust". However, during a portion of a test run the
"Particulate Sampling Train" is used to draw a fraction of
the exhaust gasses through a glass fiber filter. This
filter is later analyzed for the amount of particulate and
the ratio of combustible to non-combustible components in
the particulate (fly ash).

FUEL FLOW -

The triangular box to the right of the BCU in Fig. 11
is the "Fuel Hopper". Fuel is placed in the hopper and then
transported by means of a motor driven metering drum (see
Appendix E) down into the feed tube where a separate motor-
driven horizontal auger (see Fig. 10) pushes the fuel into
the combustion chamber.

X-Y TABLE AND PROBES -

Above the BCU in Fig. 11 is the X-Y table and gas

analysis probes. The "X-Y Probe Table" consists of computer

controlled stepper motors that turn screw shafts in both the

horizontal and vertical directions. Fig. 12 is a detailed

drawing of the X-Y table and probe attachment arrangement.

The stepper motors allow for extremely accurate probe

placement within the BCU. The movement is accurate to (

plus or minus .0005 inches) in both vertical and horizontal

directions.

The probes are the following :

1) Two (type-k) stainless steel clad thermocouples

2) Gas analysis probe

The gas analysis probe is the sampling end of a combustion

gas analysis unit CGAU (see "Control Unit"). The CGAU

measures many parameters. The parameters of importance for

this work were :

1) Carbon dioxide

2) Oxygen

3) Carbon monoxide

4) Oxides of nitrogen

5) Sulfur dioxide

6) Combustible hydrocarbons

7) "Real-time" for each sample that was "data-logged"

Other sensors provided additional information when
needed. They included, pressure gages, particulate sampling
train, and more type-k thermocouples. See Fig. 11 for
placement of these sensors. Shown schematically in Fig. 11
is the "Control Unit". The heart of this system is a micro-
computer. This computer and some associated data
acquisition hardware are used to gather temperature and gas
composition data from the probes. It also gathers
temperature data from a number of other locations in the
system and gives the commands that move the stepper motors
at the users wish. To recap the Control Units functions,
they are summarized below :

1) **Move X-Y Table (Probe Position) at users command**

2) **Sample and store data from as many as ten type-k
thermocouples**

3) **Sample and store all relevant gas composition data
from the CGAU**

To aid the investigation, a Quick-Basic program was written
that combined all three functions listed above. This meant
that most of the data acquisition was automatic and required
no additional work besides setting the initial program

parameters such as length of run and sampling rate and starting the program. Specifically, the only data reported in this experimental investigation that was not "data-logged" by the Control Unit was the data from the "Particulate Sampling Train" (see Fig. 11) and fuel flowrate.

METHODOLOGY :

The Biomass Combustion Unit (BCU) facility was used to perform three experiments as stated in the previous "Introduction". These experiments were performed while fixing many variables constant and attempting to operate in a "steady-state" manner. Steady-state implies that no changes in inlet air or fuel mass flows or properties occurred and the combustion proceeded with unchanged characteristics in time. Specifically, the following variables were held constant for all test runs :

- Under fire air flowrate and temperature
- Over fire air flowrate and temperature
- Approximately atmospheric pressure in the BCU
- Fuel mass flowrate
- The BCU was "warmed-up" (for at least two hours) to the approximate operating temperature for all runs prior to test commencement

The following physical/system variables were held constant :

- Temperature and gas analysis probes were positioned 20 inches above the grate for ALL experiments

- Test runs were for either one or one half hour duration with thirty (30) data points taken equally spaced in time for all relevant variables*.

- Over fire air tube was placed 4 inches above the grate.

* : Some data, such as that from the Particulate Sampling Train, was NOT acquired by the computer. It required direct "human" measurement.

EXPERIMENT #1 :

Introduction* - This experiment was performed to determine the "optimal" percentages of under fire air (UF%) and excess air (EA%) for one pellet specie. The pellet fuel was code named (1) (as listed previously) and found in Appendix B. "Optimal" denotes the period when the combustion gasses are highest in measured carbon dioxide (CO_2). When CO_2 is a maximum, the available carbon in the fuel is being burned most completely (produces the greatest liberation of heat). Hydrogen (H_2), is the other main combustible constituent in the wood pellets, but combustion tests (all tests found in Appendix D) indicate very little combustible hydrocarbons in the measured exhaust. This proves that "most" H_2 is burned to water vapor before reaching the gas analysis probe. Other gas properties will be analyzed in a more qualitative sense to help support the findings based on measured CO_2 percent. Table 17, gives these other variables.

* : Detailed experimental data for ALL tests performed during Experiments #1,#2, and #3, is found in Appendix D.

Table 17. Gas Property Values at Optimal Firing.

Variable	Expected Value at Optimal Firing Condition
Temperature	Maximum
Carbon Monoxide	Minimum
Oxides of Nitrogen	Maximum
Particulate (fly ash)	Minimum
Combustible (% in fly ash)	Minimum

Fig. 13 shows the parameter matrix for Experiment #1. Inside the blocks are test code numbers, i.e. test 9.2 corresponds to 41.0 UF% and 20.8 EA%.

Methodology - Tests were performed in columns of blocks with an excess air level chosen and then the five UF% levels (chosen as shown) were randomized in time. This means, for example, that tests 6.1-6.5 were performed on the same day but in random UF% order. Due to problems with the volumetric-type feed system the final EA% for any column was not the value originally chosen. The experimental matrix was designed for EA% values of 30%, 40% and 50%, however the final value varied because of the slightly variable nature of the fuel feed system. For each block, 30 data points were collected over one hour.

EXCESS AIR %

	20.8	41.0	87.2
12.6	9.4 [a]	6.4	8.3
20.0	9.1	6.2	8.1
30.0	9.5	6.3	8.2
40.0	9.2	6.5	8.5
50.0	9.3	6.1	8.4

UNDER FIRE AIR %

Figure 13. <u>Parameter Matrix for Experiment#1.</u>
Showing Specified Levels of the Two Independent
Variables, Excess Air Percent (EA%) and Under Fire
Air Percent (UF%).

* : These numbers refer to the specified test number
as listed in Appendix D. Appendix D, contains detailed
information for all parameters and measured variables
for Experiment #1, #2 and #3.

Fuel Feed Problem During Testing - It was planned to hold the mass flow of pellet (1) constant for all tests. Tests 8.1-8.5 and 9.1-9.5 have almost identical feed rates but tests 6.1-6.5 are at a feed rate 15 percent higher. It will be shown in Experiment #2 that a moderate change in feed rates is inconsequential compared to the effects of EA% and UF%.

Preliminary Analysis - Residual plots were checked for all gas analysis variables (CO, Temperature, etc.) and the plots indicated NO time trend. This means that the Biomass Combustion Unit was operating at steady-state for all tests (as assumed).

QUALITATIVE RESULTS :

Fig. 14 is a plot of six scaled gas parameters versus UF% at a specified level of EA%. This corresponds to test blocks 6.1-6.5. The "scaled" variables are the actual values divided by the largest value in a column, i.e. all CO_2 values in a column were divided by the maximum CO_2 value in that column. This yields plots with all the dependent variables scaled from zero to one which makes qualitative analysis of trends very easy.

Optimal Firing Point (Qualitative) - At 30 percent under fire air, Fig. 14, shows that Temperature, CO_2, and NO_x are at maximums, Particulate is near minimum, CO and

Combustibles are at true <u>minimums</u>. This corresponds well to the predicted optimal solution shown in Table 17. At an excess air level of 41.0 percent and 30 percent under fire air the combustion of pellet (1) was optimal.
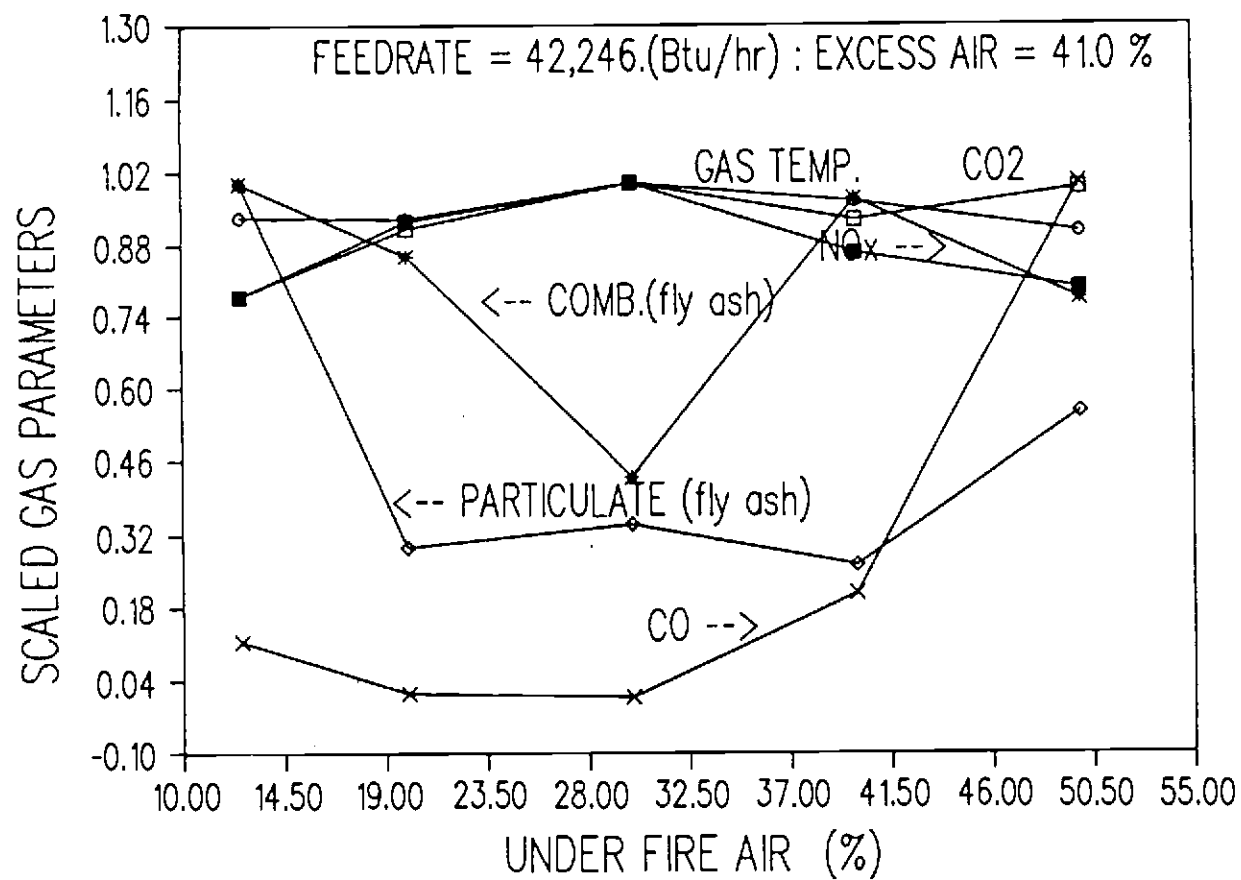
Figure 14. Gas Parameters for Pellet (1) Scaled
by the Largest Value in the Test Column. The Gas
Parameters are Plotted as a Function of UF% at a Level
of 41.0% Excess Air (41.0 EA%).

Plots like Fig. 14 were examined for tests 8.1-8.5 and 9.1-9.5, the trends in scaled gas parameters were very similar. They showed an optimal UF% of near 30 percent. One major difference occurred at the excess air level of 87.2 percent. At this level all curves were "flat" and located close to each other around the .8 (y-axis) level. It is hypothesized that this effect is due to the fact that at very high excess air levels the fuel bed experiences turbulence and there is no distinguishable "over" or "under" fire air. This hypothesis is supported by visual observation. It was observed that only a very thin fuel bed existed at this EA% level, while at the other two lower levels there were well developed fuel beds.

QUANTITATIVE RESULTS :

A new variable is defined as the CO_2-based efficiency (CO2EFF). It is the measured percentage of CO_2 in the combustion gases divided by the percentage of CO_2 calculated for the complete ("theoretical" or "stoichiometric") combustion of the available fuel. CO2EFF is defined below.

$$CO2EFF = (CO_{2measured}/CO_{2theoretical}) \times 100 \tag{16}$$

It is assumed that the combustion energy losses due to CO production, Combustibles in fly ash, and Hydrocarbons, is
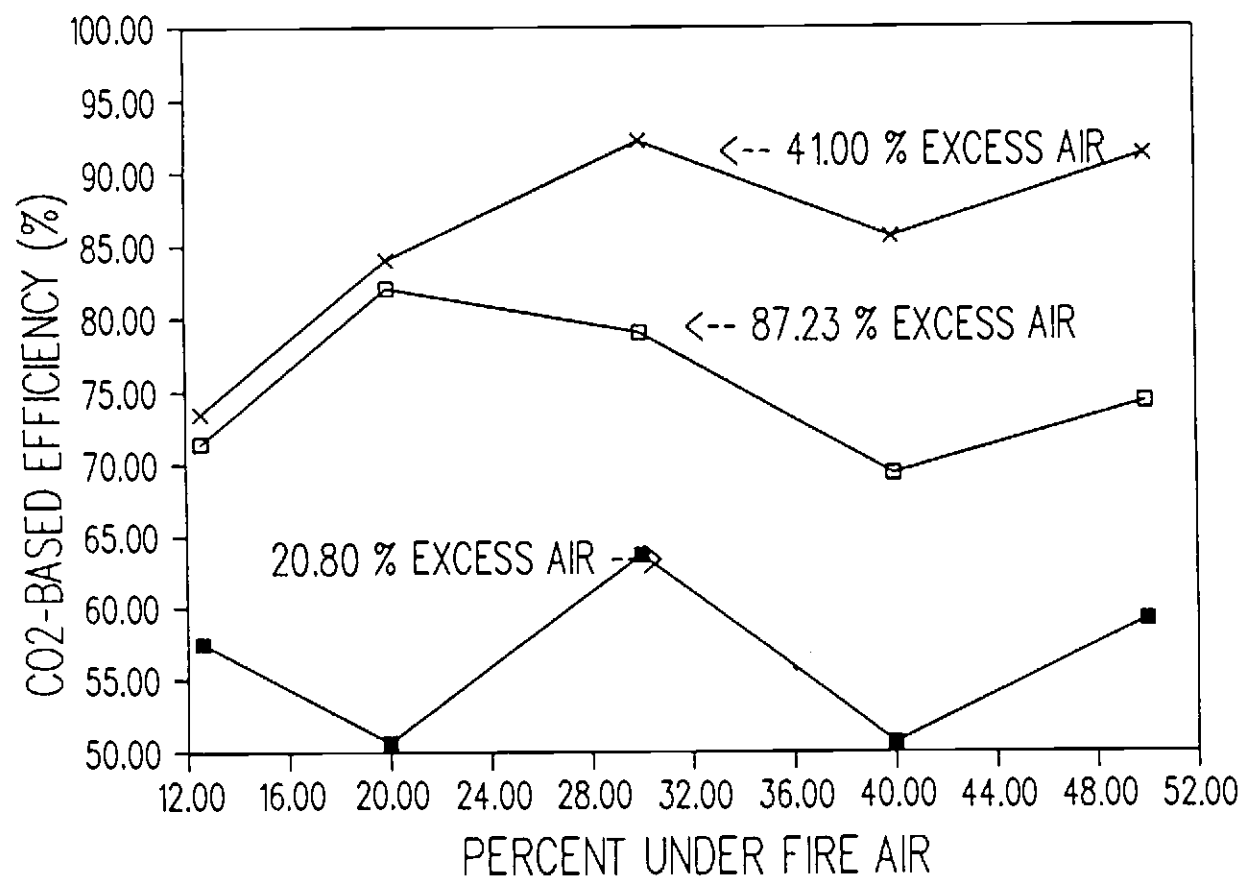
Figure 15. Level Curves of CO_2-Based Efficiency as a Function of Under Fire Air Percent at Different Excess Air Percents. This is for Tests (6.1-6.5).

For this model, R^2 = 85.68 percent is an indicator of a fairly strong association between the two independent variables (EA% and UF%) and the dependent variable (CO2EFF). Unfortunately, because there is only one observation at each point there is no error term or variance for this model. It is assumed that the qualitative evidence using Figs. 14 and 15 help support the models validity.

Next, Eqn. 17 was differentiated with respect to the two independent variables and the subsequent equations were set equal to zero and solved simultaneously. The solution was a stationary point for the CO2EFF surface and a maximum by visual observance of Fig. 16. The calculated optimal firing condition was found to be CO2EFF = 96.22 percent at EA% = 59.54, and UF% = 35.46. This corresponds fairly well with the optimal point found by graphical analysis of the raw data (Figs. 14 and 15) which gave a solution of EA% = 41.0 and UF% = 30.0.
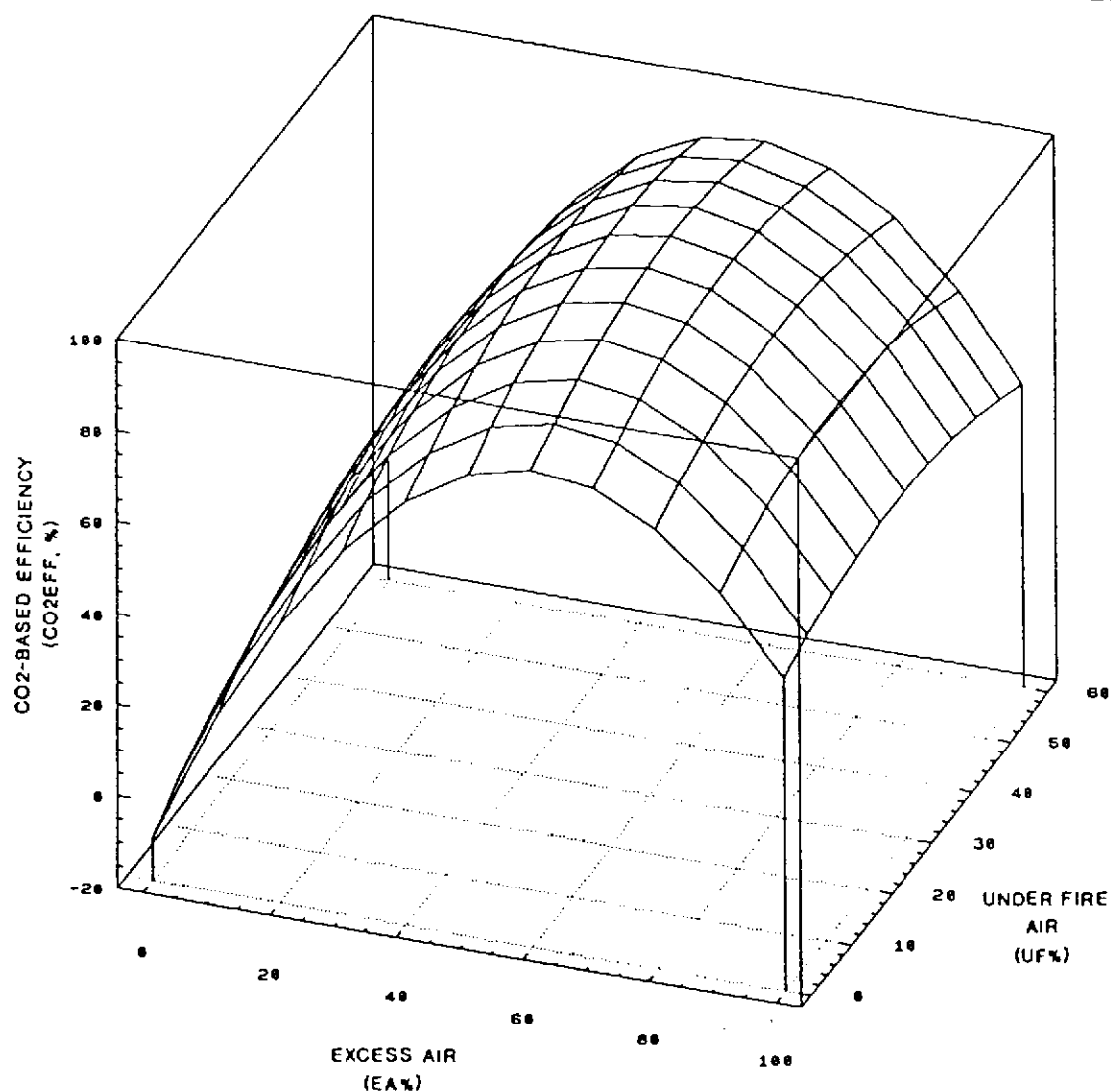
Figure 16. CO_2-Based Efficiency Surface as a Function of Excess Air Percent and Under Fire Air Percent. This Represents a Numerical Approximation of the "True" Functional Relationship and used Fifteen Discrete Data points to Fit the Model (Eqn. 17).

CONCLUSION :

The optimal firing condition for pellet fuel (l) was found to be 96.22 percent at an excess air level of 59.54 percent and under fire air level of 35.46 percent. A second order polynomial equation was fit to the data and produced a model with R^2 = 85.68 percent. This model, Eqn. 17, is presumed valid for efficiency prediction over at least the range of the two independent variables despite the fact that no error term is available.

EXPERIMENT #2 :

Introduction - This experiment was performed to investigate how different wood fuel pellets would perform during combustion with identical input values of fuel feed rate (FFR), excess air percent (EA%), and under fire air percent (UF%). The original plan was to perform the tests at "exactly" the same feed rate (mass basis), and levels of excess and under fire air percents. However, due to the fuel feed variability (mentioned in Exp. #1) it was not possible to hold FFR or EA% constant. Fortunately the UF% was held constant at 30 percent, and the variability in FFR and EA% was only 10.2 and 27.4 percent respectively.

Methodology - Unlike Exp. #1, each test was for one half hour. 30 equally spaced gas analysis data points were taken as before. All but one test was performed on the same day on fuels coded (2) - (9) and corresponding to test codes 11.1 - 11.8 respectively. Test 6.3 from Exp. #1 was included in the set because it was performed at UF% = 30 and similar FFR and EA%. Test 6.3 also corresponded to the most optimal point from Exp. #1. The order of fuel pellet firing was randomized to negate any time series effects. As mentioned above the FFR and EA% levels were preset to be the same for all tests but there was variability between tests. The FFR and EA% during any one test was still controlled very precisely. This variability in FFR is completely

attributable to the difference in feed characteristics between fuels, however, no attempt was made to correlate whether this was due to dimensional, density, or other related pellet physical variables.

Data - The easiest way to compare the performance of each fuel was to tabulate minimum (MIN), maximum (MAX), mean, and percent standard deviation (%SDEV) data in tabular form. Table 18, shows the fuel code and associated test number along with the input parameters of FFR and EA%. Remember that UF% was held constant at 30.0. This data shows that the FFR varied by only 10.2 percent whereas the EA% varied by 27.4 percent. It is also true that the range of EA% is within the "starved" or low EA% level (20.8%) and "turbulent" or high EA% level as found in Exp. #1.

Table 19, contains various combustion gas data for Exp. #2. Figures 17 and 18 are plots of gas temperature and carbon dioxide-based efficiency versus pellet fuel code.

RESULTS :

Table 19, shows that the gas temperature only varied by 5.2 percent and similarly the CO_2-based efficiency varied by only 5.4 percent. This proves that despite the difference in ash content, moisture content, elemental, proximate, and ash fusion analyses, these fuels burn with very similar properties under similar input conditions.

The carbon monoxide levels show a 41.6 percent deviation, but that is reduced to 33 percent if the far outlier (4.1% CO) is not considered.

Table 18. Fixed Parameters and Coding for Experiment #2.

CODE	TEST #	FFR (Btu/hr)	EA% (%)
1	6.3	42246.5	41.0
5	11.1	42158.4	29.2
2	11.2	35208.1	50.4
6	11.3	40735.1	33.1
7	11.4	33798.3	52.4
4	11.5	40469.6	28.7
3	11.6	34912.2	52.3
8	11.7	37437.8	47.0
9	11.8	31019.2	68.2
	MIN :	31019.2	29.2
	MAX :	42246.5	68.2
	MEAN :	37553.9	44.7
	%SDEV[a]:	10.2	27.4

[a] : %SDEV = (standard deviation/mean) x 100 ; This is used because it is a more meaningful measure of the variance for comparing different variables.

Table 19. Combustion Gas Data for Experiment #2.

	GAS TEMP. ($^\circ$F)	CO2EFF (%)	CO (ppm)	NO_x (ppm)	PARTICULATE (fly ash) (grs./dscf)	COMBUSTIBLE (fly ash) (%)
MIN :	1337.5	75.9	4.1	79.4	.029	.98
MAX :	1576.8	92.2	188.2	215.0	.705	89.6
MEAN :	1420.1	82.1	125.7	154.4	.204	16.3
%SDEV:	5.2	5.4	41.6	27.2	123.3	166.8

The particulate (fly ash) data is highly skewed by pellets coded (4), (8), and (9), which had values of particulate in the tenth's range while all other pellets had values in the hundredth's (see Appendix D). Opacity was measured for all experiments but was not reported because it was zero for all runs except tests 11.8 and 12.5, which correspond to pellet (8) which has the highest salt content. The salt content is determined by the percent chlorine by ultimate analysis. This result is reasonable because pellets (8) and (9) had the highest ash and chlorine contents of all pellets. Pellet (8) had; ash = 2.55%, Cl = .78% , pellet (9) had; ash = 2.43%, Cl = .19%. Pellet (4) had a moderately high ash content of .96 percent and no

chlorine, but its specie is Hemlock Fir which is noted in the forest products industry for burning with high opacity and particulate.

The NO_x data ranges from 79.4 to 215.0 parts per million with %SDEV equal to 27.2. It is apparent that the gas analysis probe variables (CO and NO_x, measured in parts per million) display more variability than those parameters measured in percent (see Appendix D for detail). Overall, the data on particulate and combustibles in fly ash has the largest spread. This may be due to the fact that these quantities were sampled for only 15 minutes for each test, and had a greater margin for human error than the "data-logged" variables.
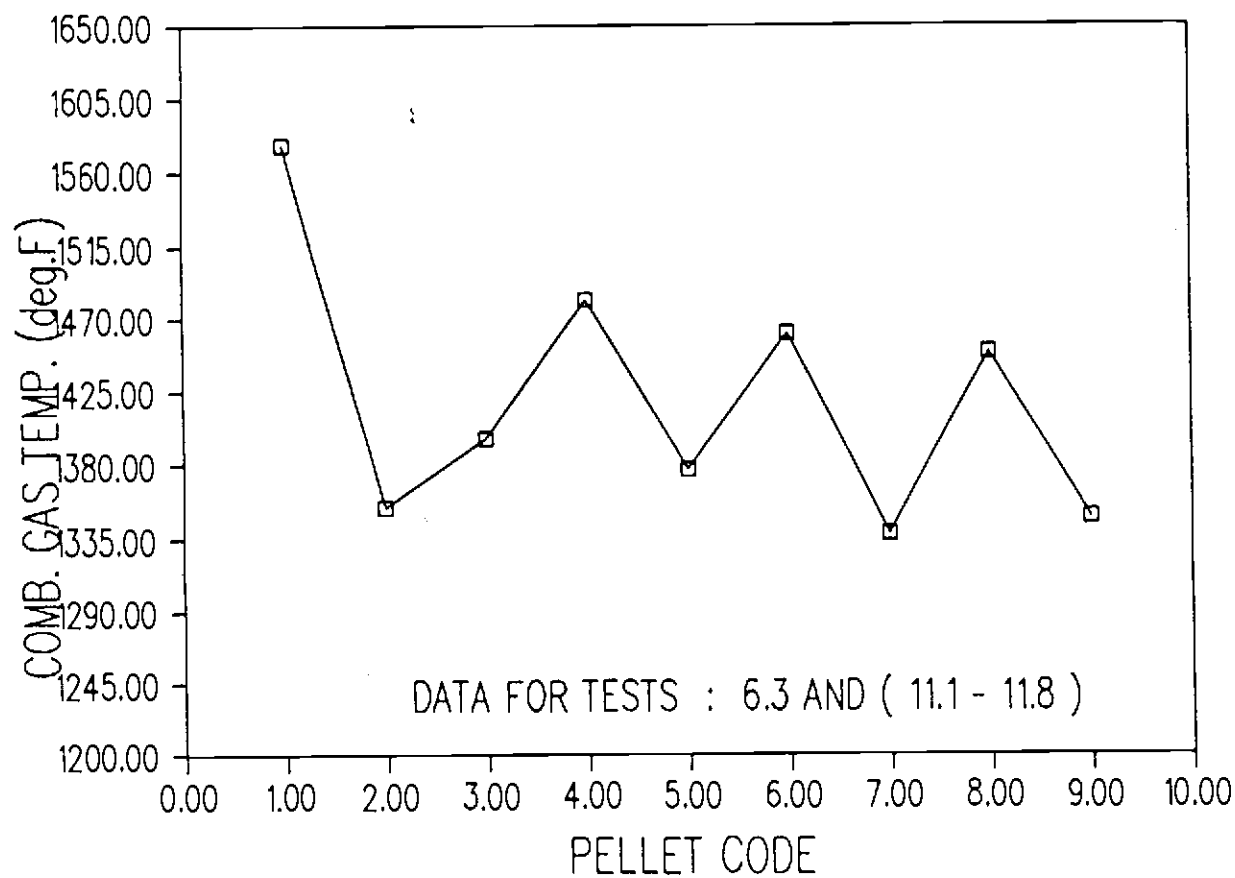
Figure 17. Plot of Combustion Gas Temperature Versus Pellet Fuel Code for Multiple Feed Rates and Excess Air Percents. (Experiment #2).
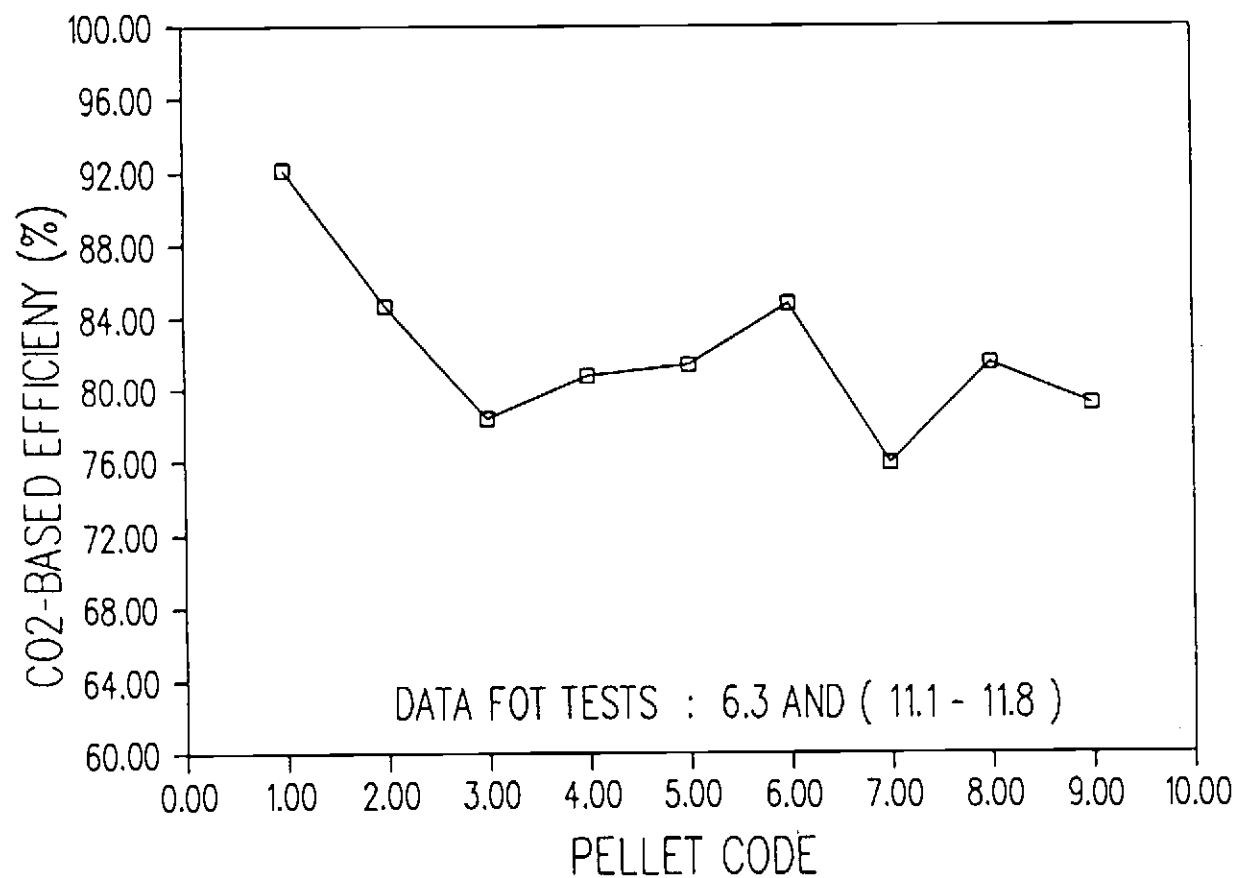
Figure 18. Plot of CO_2-Based Efficiency (CO2EFF)
Versus Pellet Fuel Code for Experiment #2.

Result of Feed Rate on CO2EFF - It was mentioned in Exp. #1 that fuel feed rate has little effect on the CO_2-based combustion efficiency (CO2EFF), at least over the ranges experienced during these tests. To support this hypothesis the data in Exp. #2 was examined.

Fig. 19, shows CO2EFF as a function of FFR (Btu/hr). A linear regression was performed that showed the slope (b1) was very small (b1 = 4.87E-4). The slope represents the unit change in CO2EFF expected for a unit change in FFR. If a test of the null hypothesis that b1 equals zero is not disproved, then this is good evidence that there is no relationship between FFR and CO2EFF. This assumes that the linear model is appropriate and by observation of the data that appears as the best choice, i.e. the data appears to have no curvature. The probability value (p) was found to be (p = .403) which is very strong evidence for the null hypothesis that b1 equals zero. This implies **NO** association between feed rate and efficiency.

OBSERVATIONAL DATA :

The most striking observation made was that after tests 11.8 and 11.9 there was visible ash in the grate after "cool-down". For all prior tests, no matter how long the test sequence, there was never any visibly remaining ash besides a "few specks". There was also fine crystalline

matter deposited on metal surfaces in the BCU combustion chamber. These surfaces were the gas analysis probes at mid to upper height and the cooling water feed tube. Both of these surfaces were relatively "cool" compared to the rest of the chamber and thus acted as condensing surfaces. Most dramatically, there was evidence of corrosion (pitting of stainless steel surfaces !) after less than one hour of burning these fuels that were high in ash and salt content. The first and only clinker formations were also experienced after cleaning the grate.
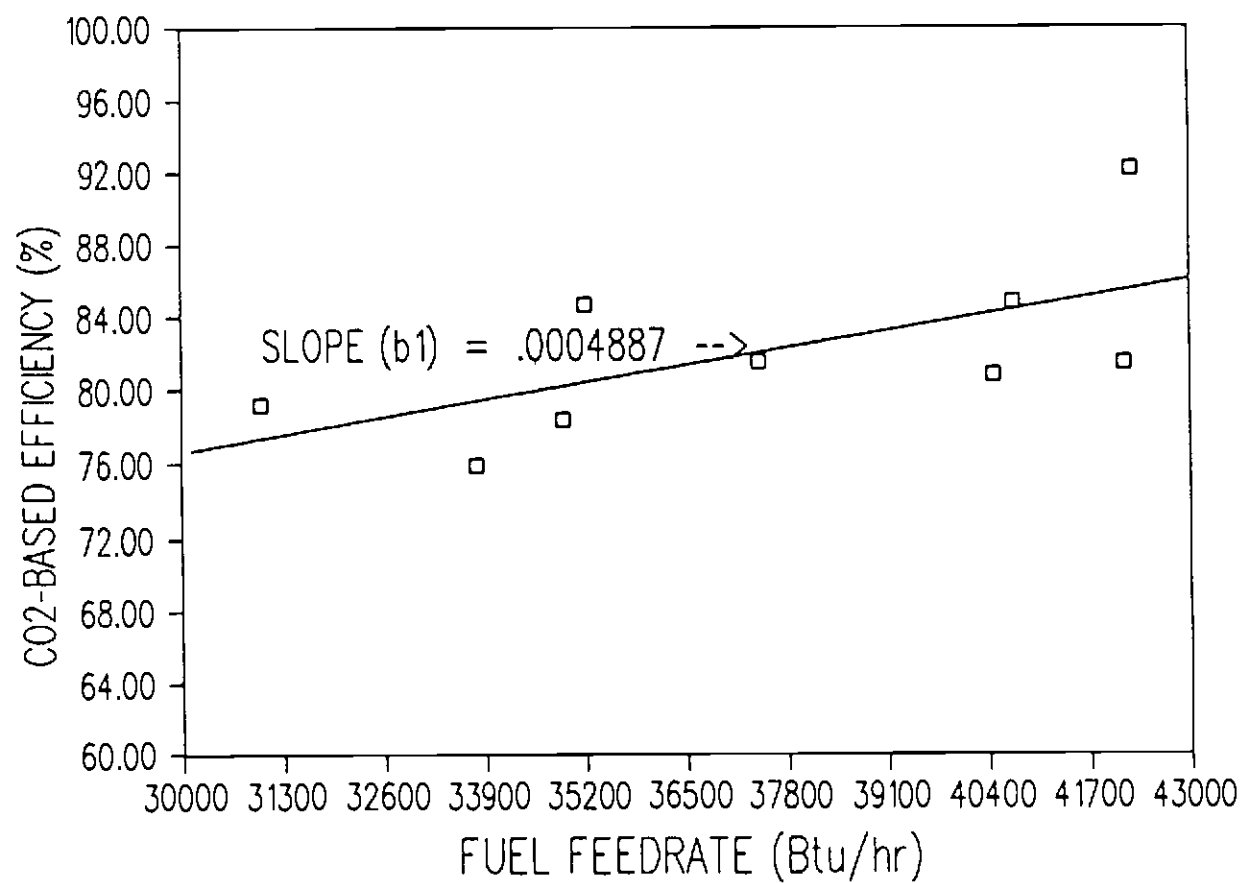
Figure 19. Plot and Linear Regression Line for Carbon
Dioxide Based Efficiency (CO2EFF) Versus Fuel Feed
Rate (FFR) for Experiment #2.

CONCLUSIONS :

(1)   Results show that two very important measures of combustion efficiency (gas temperature and carbon dioxide based efficiency) varied by only 5.2 and 5.4 percent respectively. This proves that all nine different wood fuel pellet types behave very similarly under the prescribed (similar) range of operating parameters. The overall mean efficiency for all tests was 82.1 percent and the overall mean temperature was 1420.1 deg.F.

(2)   Particulate (fly ash) and Combustible (in fly ash) data showed the greatest variability. There was evidence of a relationship between maximum values for both particulate and combustible and the percentages of ash and chlorine in the pellet fuel. The greater the percentage of ash and chlorine (salt), the greater was the fly ash problem, also, combustion efficiency was decreased by combustible losses (unburned hydrocarbons) in the fly ash.

(3)   Carbon monoxide and Oxides of Nitrogen showed the next greatest variability, but neither had data values greater than 215.0 parts per million (215.0 ppm is a very small quantity, i.e. 1 ppm = .001 grams/liter = 6.2E-5 lbm/ft^3)

(4) Visual evidence indicates that pellet fuels coded (8) and (9) are highly corrosive, produce the largest quantities of ash, and form the only slag or clinker formations of all nine fuels. The corrosion is directly attributable to salt content (or more specifically, chloride ions and compounds formed during combustion).

EXPERIMENT #3   :

Introduction - This experiment was performed to
investigate the effect of increased under fire air
temperature on combustion efficiency. Tests ("hot-tests")
were completed on five pellet species coded (1), (2), (4),
(8), and (9). The results of a hot test were compared to
the previous results of a "cold-test" on the same pellet.

Similar to Experiments #1 and #2, there was undesired
variability in the fuel feed rate. The original
experimental plan was to have each pellet fed to the Biomass
Combustion Unit at the same rate (mass basis) as the
respective cold-test. The mean difference of cold-test
minus hot-test fuel feed rate was -6611.4 (Btu/hr), or a
decrease of 16.1 percent from the mean hot-test feed rate.
The following analysis assumes that the fuel feed rate
variability is inconsequential compared to the effect of the
heated under fire air.

Methodology - Test methods were identical to
Experiment #2, except that the under fire air temperature
was increased to a mean of 306.4xF. This represents a mean
temperature rise of 230xF above the cold-test temperature,
with a standard deviation of only .18 percent.

The five pellet samples (codes) were chosen randomly
except for pellets (8) and (9). These pellets were chosen
because they were the worst fuels in terms of ash and

corrosion problems as observed in Exp. #2 and it was desired to observe them under other operating conditions. All hot-tests were accomplished in one day and the test ORDER was randomized to ease time series effects.

Table 20, shows the cold versus hot-test match-ups with the corresponding pellet code number. See Appendices C and D, for detailed pellet and combustion test data.

Table 20. Hot and Cold Under Fire Air Test Matrix.

Pellet Code	COLD-TESTS Test No.	HOT-TESTS Test No.
(1)	12.1	12.2
(2)	11.5	12.3
(4)	11.2	12.4
(8)	11.7	12.5
(9)	11.8	12.6

RESULTS :

Table 21, shows the results of the hot under fire air tests versus the cold under fire air tests.
"GTEMP" is the combustion gas temperature and CO2EFF is the CO_2-based efficiency as for Experiments #1 and #2.

Table 21. Combustion gas temperature and CO_2-based efficiency data for cold and hot under fire air tests.

Pellet	COLD-TEST		HOT-TEST	
Code	GTEMP(°F)	CO2EFF(%)	GTEMP(°F)	CO2EFF(%)
(1)	1247.63	96.37	1280.43	93.04
(2)	1354.29	84.67	1485.24	74.66
(4)	1482.34	80.80	1469.99	88.73
(8)	1448.46	81.46	1598.78	95.98
(9)	1348.10	79.24	1483.39	103.90[a]
MEAN =	1409.60	85.79	1457.00	91.26
SDEV =	106.33	6.34	128.1	9.67

[a] : Theoretically this value cannot be greater than 100%, but this more extreme value (103.90) is due to random experimental error. The combustion can be considered to be near 100 percent efficient based on measured CO_2.
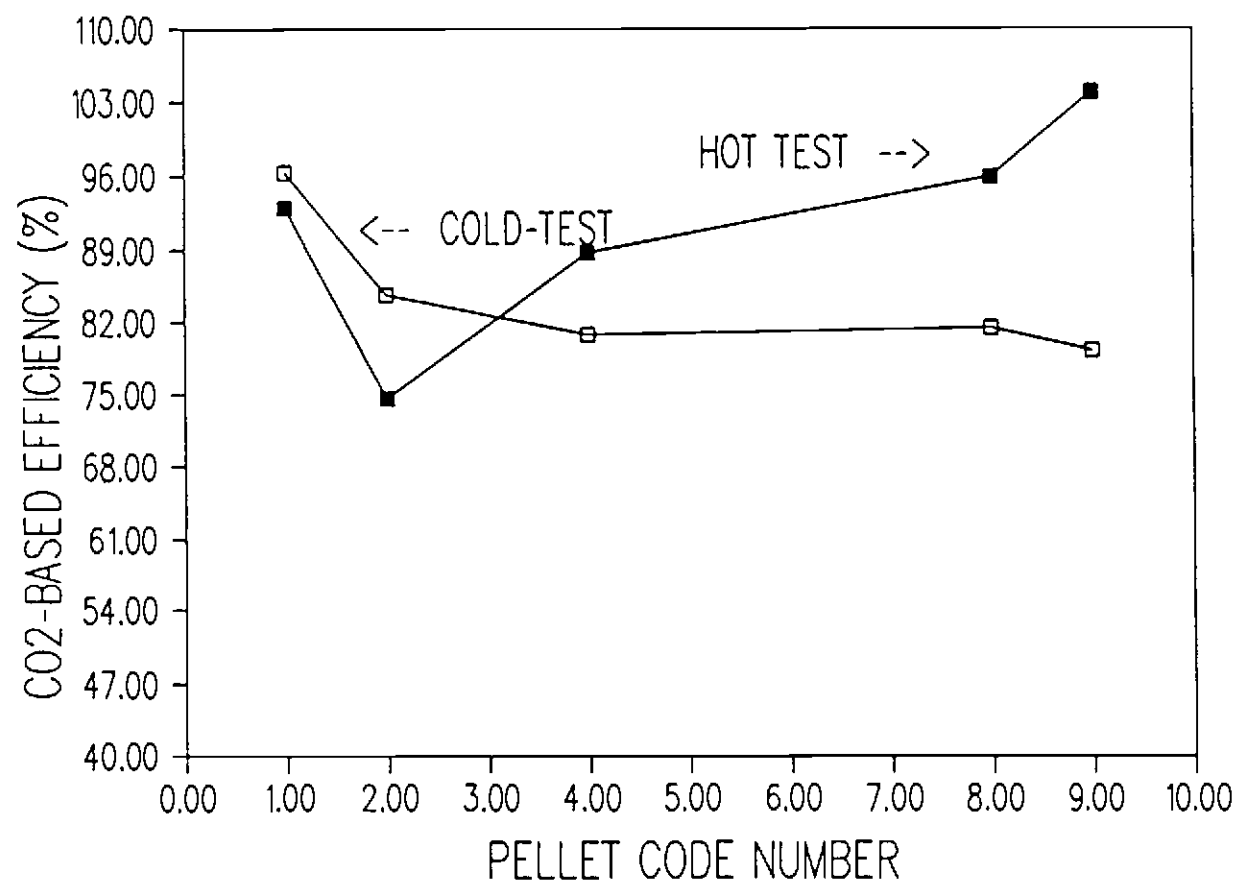
Figure 20. Carbon Dioxide Based Efficiency (CO2EFF)
Versus Fuel Code, for Cold and Hot Tests.

The graphical evidence in Fig. 20, appears to show that the hot-tests increase efficiency by a fair margin. This cannot be substantiated by statistical analysis, as will be shown next.

ANALYSIS :

The "Paired t-Test" was used to compare the values of gas temperature and CO_2-based efficiency for hot and cold tests. This statistical procedure is useful for data that is paired in some fashion (in this case the data is paired by pellet code). The paired t-test procedure helps eliminate many types of statistical dependence between paired data sets. This test assumes that the differences are Normally distributed and the samples are randomly generated.

Confidence intervals were computed at the 95 percent confidence level. The null hypothesis was that the mean difference of GTEMP or CO2EFF for the hot-test minus the cold-test was zero. The alternative hypothesis was that these mean differences were greater than zero. The alternative hypothesis (if true) would show that increased under fire air temperature does _increase_ the GTEMP and CO2EFF.

let,   DTEMP   = hot-test GTEMP - cold-test GTEMP   (18)

and,   DCO2EFF = hot-test CO2EFF - cold-test CO2EFF   (19)

The 95 % Confidence Interval for DTEMP :

$$18.24 \leq DTEMP \leq 156.56 \qquad (°F) \qquad (20)$$

The 95 % Confidence Interval for DCO2EFF :

$$-6.41 \leq DCO2EFF \leq 19.91 \qquad (\%) \qquad (21)$$

Eqn. 20, shows that the 95 percent confidence interval for DTEMP does not contain zero (all values are positive in the interval). This is strong evidence for the alternative hypothesis that mean gas temperature was increased with increased under fire air temperature.

Eqn. 21, shows the 95 percent confidence interval for the difference in efficiencies does contain zero. This is strong evidence that CO_2-based efficiency was **NOT** increased by a statistically significant amount (95% level).

CONCLUSION :

Increasing the under fire air temperature by 230°F on average did not increase the combustion efficiency (CO2EFF) by a statisticly significant amount (95% confidence level). Increasing the under fire air temperature did however increase the combustion gas temperature by 87.4°F on average, with 95 percent confidence that the mean difference was greater than zero. This average increase in GTEMP is only 6.2 percent larger than the mean cold-test GTEMP.

It was expected that increasing the under fire air temperature by 230°F on average would have a greater impact on the combustion efficiency, i.e. greater increases in GTEMP and CO2EFF. Experiment #3, demonstrates that the effort of pre-heating the under fire air had negligible effect on the overall combustion efficiency. Many hogged-fuel boilers operate with preheated air, indeed it is necessary, because of the fuels high moisture content. Some furnaces require as much as 200 percent excess (preheated) air. They find that this is necessary to sustain combustion of "wet" fuel. Note that for these experiments the pellets were "virtually" dry (15% moisture or less, Appendix C).

The particulate (fly ash), combustible (in fly ash), NO_x, and other data was not analyzed because it did not present much variability from cold to hot tests (see Appendix D).

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APPENDICES

APPENDIX   A

NOMENCLATURE

NOMENCLATURE

$\%MC_{db}$ = moisture content (dry-basis)   (dim.)

$\%MC_{WB}$ = moisture content (wet-basis)   (dim.)

$\%SDEV$ = percent standard deviation   (std. dev./mean)x100

BCU = biomass combustion unit

BLKD = pellet bulk density (lbm/ft^3)

CGAU = combustion gas analysis unit

CO2EFF = carbon dioxide-based combustion efficiency   (%)

D_b = bulk density (lbm/ft^3)

DCO2EFF= combustion gas efficiency difference (%)

DTEMP = combustion gas temperature difference (^vF)

EA% = excess air percent (%)

FFR = pellet fuel feed rate (Btu/hr) or (lbm/hr)

GTEMP = combustion gas temperature (^vF)

H_{bw} = specific energy needed to break adsorption bonds
     (Btu/lbm)

h_{fh} = enthalpy of evaporation for water (Btu/lbm)

HHV = higher heating value (Btu/lbm)

LHV = lower heating value (Btu/lbm)

LHV2 = lower heating value two (Btu/lbm)

MSW = municipal solid waste

OF% = over fire air percent (%)

Q_{fw} = rate of energy to vaporize free and bound water
     (Btu/hr)

Q_{H2} = heat loss rate due to vaporization of fuel bound
     hydrogen (Btu/hr)

Q_{tot} = total rate of energy to vaporize fuel bound moisture and moisture from combustion of fuel hydrogen (Btu/hr)

Q_v = heat content per unit volume of fuel (Btu/ft^3)

RDF = refuse (MSW) derived fuel

SPD = pellet specific density (lbm/ft^3)

UF% = under fire air percent (%)

v_f = specific volume of water, fluid state (ft^3/lbm)

v_g = specific volume of water, liquid state (ft^3/lbm)

APPENDIX   B

PELLET CODES

PELLET SAMPLE CODING

The following dual code scheme is listed so that this document may be used as a reference in conjunction with other work being done at OSU on the same biomass pellet project. The codes on the left were used by the researchers for all phases of the work (this thesis does not cover all work performed during the biomass fuel characterization project). For this thesis, the coding titled "THESIS Codes" in Table 22 on the next page will be used.

Table 22. Pellet Sample Coding Used in this Thesis
and for Other Work Performed at OSU.

OSU Code Name	THESIS Code
BCCPP824-1AB*	1
FHLDF624-1AB	2
FHLDF624-2AB	3
PHCHF706-2AB	4
EVCMX713-1AB	5
WSPCD715-1AB	6
KMPMX727-2AB	7
SPCDF727-1AB	8
WFPMX920-1AB	9
PHCMX706-1	10
HSIMX824-1	11
BTPMX920-1	12
WDMMX920-1	13
RMMMX920-1	14

* : A => Pellets were analyzed for Proximate and Ultimate
        Analysis.

  B => Pellets were burned for the experimental data
        analyzed in this thesis.

  If an "A" or "B" is not present, this means that the
  pellets were anlayzed for a subset of the variables
  included in this report excluding ultimate and
  proximate analysis and experimental burning.

APPENDIX   C

PELLET FUEL DATA

PELLET SAMPLE DATA

Pellet Code : 1

Pellet Species : Ponderosa Pine (wood only)

Location of Raw Material : Lower "Pan Handle" Idaho

Grade : Commercial Pellet

ULTIMATE ANALYSIS

(dry weight basis)

% Carbon = 51.20   % Hydrogen = 6.35

% Oxygen = 41.97   % Nitrogen = .25

% Sulphur = .01   % Chlorine = .01

% Ash   = .22

PROXIMATE ANALYSIS

(dry weight basis)

% Fixed carbon = 16.63   % Volatile = 83.15

% Ash = same as in ultimate analysis

ASH FUSION DATA

Initial   = 2450.00 (deg.F)

H/W   = 2470.00 (deg.F)

1/2-H/W   = 2480.00 (deg.F)

Fluid   = 2510.00 (deg.F)

Note : There is more data on the next page for this pellet.

ADDITIONAL PELLET FUEL PARAMETERS

Rapeseed Supplement (% wet basis)[a] = 0.00

Higher Heating Value = 8967.63 (Btu/lbm)

Moisture Content (% wet basis) = 8.25

Bulk Density = 38.63 (lbm/ft^3)

Specific Density = 81.28 (lbm/ft^3)

Mean Length = .266 (inches)

Mean Diameter = .323 (inches)

[a] : Rapeseed was added in small percentages to some hogged biomass that was collected by OSU to be made into pellets. The rapeseed aids in pellet manufacture.

PELLET SAMPLE DATA

Pellet Code : 2

Pellet Species : Douglas Fir (wood + bark)

Location of Raw Material : Central Western Oregon

Grade : Non-Commercial (made for OSU)

ULTIMATE ANALYSIS

(dry weight basis)

% Carbon	=	50.82	% Hydrogen = 6.35	
% Oxygen	=	42.54	% Nitrogen = .06	
% Sulphur	=	.02	% Chlorine = 0.00	
% Ash	=	.21		

PROXIMATE ANALYSIS

(dry weight basis)

% Fixed carbon = 15.66   % Volatile = 84.13

% Ash   = same as in ultimate analysis

ASH FUSION DATA

Initial   = 2510.00 (°F)

H/W   = unav. (°F)

1/2-H/W   = unav. (°F)

Fluid   = 2540.00 (°F)

Note : There is more data on the next page for this pellet.

ADDITIONAL PELLET FUEL PARAMETERS

Rapeseed Supplement (% wet basis)[a] = 1.00

Higher Heating Value = 8928.29 (Btu/lbm)

Moisture Content (% wet basis) = 11.20

Bulk Density = 45.50 (lbm/ft^3)

Specific Density = 80.64 (lbm/ft^3)

Mean Length = .701 (inches)

Mean Diameter = .312 (inches)

[a] : Rapeseed was added in small percentages to some hogged biomass that was collected by OSU to be made into pellets. The rapeseed aids in pellet manufacture.

PELLET SAMPLE DATA

Pellet Code : 3

Pellet Species : Douglas Fir (wood + bark)

Location of Raw Material : Central Western Oregon

Grade : Non-Commercial (made for OSU)

ULTIMATE ANALYSIS

(dry weight basis)

% Carbon = 53.29		% Hydrogen = 6.16
% Oxygen = 39.42		% Nitrogen = .13
% Sulphur = .01		% Chlorine = 0.00
% Ash = .99		

PROXIMATE ANALYSIS

(dry weight basis)

% Fixed carbon = 20.88   % Volatile = 78.13

% Ash   = same as in ultimate analysis

ASH FUSION DATA

Initial   = 2210.00 ($^{\circ}$F)

H/W   = unav. ($^{\circ}$F)

1/2-H/W   = unav. ($^{\circ}$F)

Fluid   = 2250.00 ($^{\circ}$F)

Note : There is more data on the next page for this pellet.

ADDITIONAL PELLET FUEL PARAMETERS

Rapeseed Supplement (% wet basis)[a] = 2.00

Higher Heating Value = 8970.01 (Btu/lbm)

Moisture Content (% wet basis) = 11.20

Bulk Density = 45.50 (lbm/ft^3)

Specific Density = 80.64 (lbm/ft^3)

Mean Length = .701 (inches)

Mean Diameter = .312 (inches)

[a] : Rapeseed was added in small percentages to some hogged biomass that was collected by OSU to be made into pellets. The rapeseed aids in pellet manufacture.

PELLET SAMPLE DATA

Pellet Code : 4

Pellet Species : Hemlock Fir (wood + bark)

Location of Raw Material : Central Western Oregon

Grade : Non-Commercial (made for OSU)

ULTIMATE ANALYSIS

(dry weight basis)

% Carbon	=	51.16	% Hydrogen =	6.09
% Oxygen	=	41.68	% Nitrogen =	.10
% Sulphur	=	.01	% Chlorine =	0.003
% Ash	=	.96		

PROXIMATE ANALYSIS

(dry weight basis)

% Fixed carbon = 21.06   % Volatile = 77.98

% Ash   = same as in ultimate analysis

ASH FUSION DATA

Initial   = 2500.00 (°F)

H/W   = 2530.00 (°F)

1/2-H/W   = 2540.00 (°F)

Fluid   = 2550.00 (°F)

Note : There is more data on the next page for this pellet.

ADDITIONAL PELLET FUEL PARAMETERS

Rapeseed Supplement (% wet basis)[a] = 0.00

Higher Heating Value = 8786.94 (Btu/lbm)

Moisture Content (% wet basis) = 8.40

Bulk Density = 48.16 (lbm/ft^3)

Specific Density = 83.92 (lbm/ft^3)

Mean Length = .518 (inches)

Mean Diameter = .310 (inches)

[a] : Rapeseed was added in small percentages to some hogged biomass that was collected by OSU to be made into pellets. The rapeseed aids in pellet manufacture.

PELLET SAMPLE DATA

Pellet Code :   5

Pellet Species:Alder,Hemlock Fir,Doug.Fir,Cedar (wood+bark)

Location of Raw Material : Central Coast Oregon

Grade : Non-Commercial (made for OSU)

ULTIMATE ANALYSIS

(dry weight basis)

% Carbon	=	53.41	% Hydrogen	=	6.05
% Oxygen	=	37.99	% Nitrogen	=	.27
% Sulphur	=	.03	% Chlorine	=	0.00
% Ash	=	2.24			

PROXIMATE ANALYSIS

(dry weight basis)

% Fixed carbon = 23.78   % Volatile = 73.98

% Ash   = same as in ultimate analysis

ASH FUSION DATA

Initial   = 2260.00 (°F)

H/W   = 2270.00 (°F)

1/2-H/W   = 2275.00 (°F)

Fluid   = 2280.00 (°F)

Note : There is more data on the next page for this pellet.

ADDITIONAL PELLET FUEL PARAMETERS

Rapeseed Supplement (% wet basis)[a] = 0.25

Higher Heating Value = 9185.71 (Btu/lbm)

Moisture Content (% wet basis) = 3.40

Bulk Density = 44.47 (lbm/ft^3)

Specific Density = 81.57 (lbm/ft^3)

Mean Length = .317 (inches)

Mean Diameter = .315 (inches)

[a] : Rapeseed was added in small percentages to some hogged biomass that was collected by OSU to be made into pellets. The rapeseed aids in pellet manufacture.

PELLET SAMPLE DATA

Pellet Code :   6

Pellet Species : Cedar (wood + bark)

Location of Raw Material : South Central Oregon

Grade : Non-Commercial (made for OSU)

ULTIMATE ANALYSIS

(dry weight basis)

% Carbon	=	52.10	% Hydrogen	=	6.15
% Oxygen	=	41.03	% Nitrogen	=	.01
% Sulphur	=	.01	% Chlorine	=	0.00
% Ash	=	.61		

PROXIMATE ANALYSIS

(dry weight basis)

% Fixed carbon = 18.69   % Volatile = 80.70

% Ash   = same as in ultimate analysis

ASH FUSION DATA

Initial   = 2220.00 (°F)

H/W   = 2230.00 (°F)

1/2-H/W   = 2240.00 (°F)

Fluid   = 2250.00 (°F)

Note : There is more data on the next page for this pellet.

ADDITIONAL PELLET FUEL PARAMETERS

Rapeseed Supplement (% wet basis)[a] = 0.25

Higher Heating Value = 9141.63 (Btu/lbm)

Moisture Content (% wet basis) = 7.80

Bulk Density = 48.95 (lbm/ft^3)

Specific Density = 82.38 (lbm/ft^3)

Mean Length = .46 (inches)

Mean Diameter = .307 (inches)

[a] : Rapeseed was added in small percentages to some hogged biomass that was collected by OSU to be made into pellets. The rapeseed aids in pellet manufacture.

PELLET SAMPLE DATA

Pellet Code :   7

Pellet Species: Red Alder, some Maple/Myrtle (wood+bark)

Location of Raw Material : Central Coast Oregon

Grade   : Non-Commercial (made for OSU)

ULTIMATE ANALYSIS

(dry weight basis)

% Carbon	=	50.35	% Hydrogen =	5.92
% Oxygen	=	42.29	% Nitrogen =	.27
% Sulphur	=	.03	% Chlorine =	0.00
% Ash	=	1.15		

PROXIMATE ANALYSIS

(dry weight basis)

% Fixed carbon = 19.25   % Volatile = 79.60

% Ash   =   same as in ultimate analysis

ASH FUSION DATA

Initial   = 2220.00 ($^\circ$F)

H/W   = 2220.00 ($^\circ$F)

1/2-H/W   = 2230.00 ($^\circ$F)

Fluid   = 2240.00 ($^\circ$F)

Note : There is more data on the next page for this pellet.

ADDITIONAL PELLET FUEL PARAMETERS

Rapeseed Supplement (% wet basis)[a] = 0.50

Higher Heating Value = 8688.26 (Btu/lbm)

Moisture Content (% wet basis) = 6.60

Bulk Density = 53.34 (lbm/ft^3)

Specific Density = 82.86 (lbm/ft^3)

Mean Length = .705 (inches)

Mean Diameter = .305 (inches)

[a] : Rapeseed was added in small percentages to some hogged biomass that was collected by OSU to be made into pellets. The rapeseed aids in pellet manufacture.

PELLET SAMPLE DATA

Pellet Code : 8

Pellet Species : Douglas Fir (wood + bark)

Location of Raw Material : Central Coast Oregon

Grade : Non-Commercial (made for OSU)

ULTIMATE ANALYSIS

(dry weight basis)

% Carbon	=	54.16	% Hydrogen	=	5.93
% Oxygen	=	37.11	% Nitrogen	=	.18
% Sulphur	=	.07	% Chlorine	=	0.78
% Ash	=	2.55			

PROXIMATE ANALYSIS

(dry weight basis)

% Fixed carbon = 25.85   % Volatile = 71.60

% Ash   = same as in ultimate analysis

ASH FUSION DATA

Initial   = 2450.00 (°F)

H/W   = 2460.00 (°F)

1/2-H/W   = 2470.00 (°F)

Fluid   = 2480.00 (°F)

Note : There is more data on the next page for this pellet.

ADDITIONAL PELLET FUEL PARAMETERS

Rapeseed Supplement (% wet basis)[a] = 0.50

Higher Heating Value = 9284.34 (Btu/lbm)

Moisture Content (% wet basis) = 8.00

Bulk Density = 43.14 (lbm/ft^3)

Specific Density = 79.70 (lbm/ft^3)

Mean Length = .376 (inches)

Mean Diameter = .314 (inches)

[a] : Rapeseed was added in small percentages to some hogged biomass that was collected by OSU to be made into pellets. The rapeseed aids in pellet manufacture.

PELLET SAMPLE DATA

Pellet Code : 9

Pellet Species : Hemlock Fir and Sitka Spruce (wood + bark)

Location of Raw Material : Southeast Coastal Alaska

Grade : Non-Commercial (made for OSU)

ULTIMATE ANALYSIS

(dry weight basis)

% Carbon = 50.55   % Hydrogen = 6.04

% Oxygen = 40.40   % Nitrogen = .35

% Sulphur = .04   % Chlorine = 0.19

% Ash   = 2.43

PROXIMATE ANALYSIS

(dry weight basis)

% Fixed carbon = 24.27   % Volatile = 73.30

% Ash   = same as in ultimate analysis

ASH FUSION DATA

Initial = 2150.00 (°F)

H/W   = 2160.00 (°F)

1/2-H/W = 2170.00 (°F)

Fluid   = 2195.00 (°F)

Note : There is more data on the next page for this pellet.

ADDITIONAL PELLET FUEL PARAMETERS

Rapeseed Supplement (% wet basis)[a] = 0.25

Higher Heating Value = 8799.78 (Btu/lbm)

Moisture Content (% wet basis) = 14.40

Bulk Density = 37.21 (lbm/ft^3)

Specific Density = 75.32 (lbm/ft^3)

Mean Length = .601 (inches)

Mean Diameter = .305 (inches)

[a] : Rapeseed was added in small percentages to some hogged biomass that was collected by OSU to be made into pellets. The rapeseed aids in pellet manufacture.

PELLET SAMPLE DATA

Pellet Code : 10

Pellet Species : Douglas Fir and Alder (wood + bark)

Location of Raw Material : Central Western Oregon

Grade : Non-Commercial (made for OSU)

PELLET FUEL PARAMETERS

Higher Heating Value = 8960.40 (Btu/lbm)

Moisture Content (% wet basis) = 4.90

Bulk Density = 47.70 (lbm/ft^2)

Specific Density = 81.76 (lbm/ft^3)

Mean Length = .392 (inches)

Mean Diameter = .309 (inches)

PELLET SAMPLE DATA

Pellet Code : 11

Pellet Species : Cedar and Spruce (wood + bark)

Location of Raw Material : Central "Pan-Handle"

Grade : Commercial

PELLET FUEL PARAMETERS

Higher Heating Value = 8964.52 (Btu/lbm)

Moisture Content (% wet basis) = 9.13

Bulk Density = 43.68 (lbm/ft^3)

Specific Density = 81.08 (lbm/ft^3)

Mean Length = .545 (inches)

Mean Diameter = .309 (inches)

PELLET SAMPLE DATA

Pellet Code :   12

Pellet Species   :   True Fir and Pine (wood and bark)

Location of Raw Material   :   Northwestern Montana

Grade   :   Commercial

PELLET FUEL PARAMETERS

Higher Heating Value =   8850.21 (Btu/lbm)

Moisture Content (% wet basis) =   7.00

Bulk Density   =   41.40 (lbm/ft^3)

Specific Density =   81.56 (lbm/ft^3)

Mean Length =   .500 (inches)

Mean Diameter =   .256 (inches)

PELLET SAMPLE DATA

<u>Pellet Code</u> :   13

Pellet Species : Douglas Fir and Ponderosa Pine (wood+bark)

Location of Raw Material :   Northwestern Montana

Grade   :   Commercial

<u>PELLET FUEL PARAMETERS</u>

Higher Heating Value = 8755.31 (Btu/lbm)

Moisture Content (% wet basis) = 4.60

Bulk Density = 44.77 (lbm/ft^3)

Specific Density = 82.65 (lbm/ft^3)

Mean Length = .495 (inches)

Mean Diameter = .314 (inches)

PELLET SAMPLE DATA

Pellet Code : 14

Pellet Species : Douglas Fir and Ponderosa Pine (wood+bark)

Location of Raw Material : Northwestern Montana

Grade : Commercial

PELLET FUEL PARAMETERS

Higher Heating Value = 8637.99 (Btu/lbm)

Moisture Content (% wet basis) = 6.90

Bulk Density = 46.02 (lbm/ft^3)

Specific Density = 81.64 (lbm/ft^3)

Mean Length = .596 (inches)

Mean Diameter = .317 (inches)

APPENDIX D

COMBUSTION EXPERIMENT DATA

COMBUSTION TEST DATA

TEST # 6.1   FUEL CODE : 1

OBJECTIVE : One "block" (out of 15) of the experimental

matrix to find optimal firing condition as a function of

excess air and under fire air for fuel #1.

Length of run = 60 (minutes)

FUEL AND AIR PARAMETERS (CONSTANT FOR TEST)

Fuel feedrate 1 (FF1) = 4.711 (lb/hr-dry basis)

Air/Fuel Ratio (A/F) = 6.265 (lb-dry air/lb-dry fuel)

Fuel feedrate 2 (FF2) = 42249.76 (Btu/hr)

Excess Air (%EA) percent = 41.00

Under fire air percent (%UF) = 50.00

Under-fire (UF) air supply temperature (TUF) = 69 (xF)

Over-fire (OF) air supply temperature[a] (TOF) = 69 ($^\circ$F)

[a] : OF air temperature is measured before entrance to the
Biomass Combustion Unit (BCU). This is not the actual
supply temperature. It was not feasible to measure the
actual OF supply air (heated as it travels down the OF tube
inside the BCU) because of the difficulty of thermocouple
placement and lifespan in the harsh combustion gas
environment.

COMBUSTION GAS DATA

(From Enerac Gas Analysis Unit and Separate Temp. Probes)

Note : All data is given as the mean value first and the standard deviation second, separated by a colon. Example – "mean CO_2 value" : "standard deviation of mean CO_2"

- Gas temperature (T_g) = 1428.25 : 40.45 ($^\circ$F)

- Carbon monoxide (CO) = 431.87 : 638.01 (ppm)

- Oxygen (O_2) = 7.85 : 2.82 (% by dry volume)

- Carbon dioxide (CO_2) = 12.86 : 2.76 (% by dry volume)

- Hydrocarbons (HCs) = .60 : 1.80 (% by dry volume)

- Oxides of Nitrogen (NO_x) = 68.17 : 21.90 (ppm)

- Sulphur dioxide (SO_2) = 9.7 : 32.04 (ppm)

- Particulate in exhaust (PART.) = .1161 (grains/dscf)[a]

- Combustible in Particulate (COMB.) = 67.88 (% dry basis)

[a] : dscf = dry standard cubic foot ; grain = 1/7000th ounce; data adjusted to 12% CO_2.

COMBUSTION TEST DATA

TEST # 6.2   FUEL CODE : 1

OBJECTIVE : One "block" (out of 15) of the experimental
matrix to find optimal firing condition as a function of
excess air and under fire air for fuel #1.

Length of run = 60 (minutes)

FUEL AND AIR PARAMETERS (CONSTANT FOR TEST)

Fuel feedrate 1 (FF1) = 4.711 (lb/hr-dry basis)

Air/Fuel Ratio (A/F) = 6.265 (lb-dry air/lb-dry fuel)

Fuel feedrate 2 (FF2) = 42249.76 (Btu/hr)

Excess Air (%EA) percent = 41.00

Under fire air percent (%UF) = 20.00

Under-fire (UF) air supply temperature (TUF) = 69 ($^\circ$F)

Over-fire (OF) air supply temperature[ə] (TOF) = 68 ($^\circ$F)

[ə] : OF air temperature is measured before entrance to the
Biomass Combustion Unit (BCU). This is not the actual
supply temperature. It was not feasible to measure the
actual OF supply air (heated as it travels down the OF tube
inside the BCU) because of the difficulty of thermocouple
placement and lifespan in the harsh combustion gas
environment.

COMBUSTION GAS DATA

(From Enerac Gas Analysis Unit and Separate Temp. Probes)

Note : All data is given as the mean value first and the standard deviation second, separated by a colon. Example – "mean CO_2 value" : "standard deviation of mean CO_2"

- Gas temperature (T_g) = 1468.10 : 48.22 ($°F$)

- Carbon monoxide (CO) = 6.93 : 23.86 (ppm)

- Oxygen (O_2) = 8.91 : 1.98 (% by dry volume)

- Carbon dioxide (CO_2) = 11.84 : 1.98 (% by dry volume)

- Hydrocarbons (HCs) = 0.0 : 0.00 (% by dry volume)

- Oxides of Nitrogen (NO_x) = 79.43 : 16.53 (ppm)

- Sulphur dioxide (SO_2) = 0.0 : 0.00 (ppm)

- Particulate in exhaust (PART.) = .0345 (grains/dscf)[a]

- Combustible in Particulate (COMB.) = 58.30 (% dry basis)

[a] : dscf = dry standard cubic foot ; grain = 1/7000th ounce; data are adjusted to 12% CO_2.

COMBUSTION TEST DATA

TEST # 6.3   FUEL CODE : 1

OBJECTIVE : One "block" (out of 15) of the experimental

matrix to find optimal firing condition as a function of

excess air and under fire air for fuel #1.

Length of run = 60 (minutes)

FUEL AND AIR PARAMETERS (CONSTANT FOR TEST)

Fuel feedrate 1 (FF1) = 4.711 (lb/hr-dry basis)

Air/Fuel Ratio (A/F) = 6.265 (lb-dry air/lb-dry fuel)

Fuel feedrate 2 (FF2) = 42249.76 (Btu/hr)

Excess Air (%EA) percent = 41.00

Under fire air percent (%UF) = 30.00

Under-fire (UF) air supply temperature (TUF) = 77 ($^\circ$F)

Over-fire (OF) air supply temperature[a] (TOF) = 70 ($^\circ$F)

[a] : OF air temperature is measured before entrance to the
Biomass Combustion Unit (BCU). This is not the actual
supply temperature. It was not feasible to measure the
actual OF supply air (heated as it travels down the OF tube
inside the BCU) because of the difficulty of thermocouple
placement and lifespan in the harsh combustion gas
environment.

COMBUSTION GAS DATA

(From Enerac Gas Analysis Unit and Separate Temp. Probes)

Note : All data is given as the mean value first and the standard deviation second, separated by a colon. Example - "mean CO_2 value" : "standard deviation of mean CO_2"

- Gas temperature (T_g) = 1576.80 : 64.85 (°F)

- Carbon monoxide (CO) = 4.07 : 16.14 (ppm)

- Oxygen (O_2) = 7.72 : 2.83 (% by dry volume)

- Carbon dioxide (CO_2) = 12.99 : 2.79 (% by dry volume)

- Hydrocarbons (HCs) = .10 : 0.51 (% by dry volume)

- Oxides of Nitrogen (NO_x) = 85.77 : 25.32 (ppm)

- Sulphur dioxide (SO_2) = 1.57 : 6.390.00 (ppm)

- Particulate in exhaust (PART.) = .0396 (grains/dscf)[a]

- Combustible in Particulate (COMB.) = 29.19 (% dry basis)

[a] : dscf = dry standard cubic foot ; grain = 1/7000th ounce; data are adjusted to 12% CO_2.

COMBUSTION TEST DATA

TEST # 6.4   FUEL CODE : 1

OBJECTIVE : One "block" (out of 15) of the experimental matrix to find optimal firing condition as a function of excess air and under fire air for fuel #1.

Length of run = 60 (minutes)

FUEL AND AIR PARAMETERS (CONSTANT FOR TEST)

Fuel feedrate 1 (FF1)   =   4.711 (lb/hr-dry basis)

Air/Fuel Ratio (A/F)   =   6.265 (lb-dry air/lb-dry fuel)

Fuel feedrate 2 (FF2)   =   42249.76 (Btu/hr)

Excess Air (%EA) percent   =   41.00

Under fire air percent (%UF)   =   12.60

Under-fire (UF) air supply temperature (TUF)   =   85 ($^\circ$F)

Over-fire (OF) air supply temperature^a (TOF)   =   69 ($^\circ$F)

^{a} : OF air temperature is measured before entrance to the Biomass Combustion Unit (BCU). This is not the actual supply temperature. It was not feasible to measure the actual OF supply air (heated as it travels down the OF tube inside the BCU) because of the difficulty of thermocouple placement and lifespan in the harsh combustion gas environment.

COMBUSTION GAS DATA

(From Enerac Gas Analysis Unit and Separate Temp. Probes)

Note : All data is given as the mean value first and the standard deviation second, separated by a colon. Example – "mean CO_2 value" : "standard deviation of mean CO_2"

- Gas temperature (T_g)   =   1472.80 : 29.84 ($^\circ$F)

- Carbon monoxide (CO)   =   49.97 : 265.02 (ppm)

- Oxygen (O_2)   =   10.36 : 1.76 (% by dry volume)

- Carbon dioxide (CO_2)   =   10.13 : 2.53 (% by dry volume)

- Hydrocarbons (HCs)   =   0.0 : 0.0 (% by dry volume)

- Oxides of Nitrogen (NO_x)   =   66.83 : 14.23 (ppm)

- Sulphur dioxide (SO_2)   =   0.00 : 0.00 (ppm)

- Particulate in exhaust (PART.)   =   .0305 (grains/dscf)[a]

- Combustible in Particulate (COMB.)   =   65.80 (% dry basis)

[a] : dscf = dry standard cubic foot ; grain = 1/7000th ounce; data are adjusted to 12% CO_2.

COMBUSTION TEST DATA

TEST # 6.5   FUEL CODE : 1

OBJECTIVE : One "block" (out of 15) of the experimental matrix to find optimal firing condition as a function of excess air and under fire air for fuel #1.

Length of run = 60 (minutes)

FUEL AND AIR PARAMETERS (CONSTANT FOR TEST)

Fuel feedrate 1 (FF1) = 4.711 (lb/hr-dry basis)

Air/Fuel Ratio (A/F) = 6.265 (lb-dry air/lb-dry fuel)

Fuel feedrate 2 (FF2) = 42249.76 (Btu/hr)

Excess Air (%EA) percent = 41.00

Under fire air percent (%UF) = 40.00

Under-fire (UF) air supply temperature (TUF) = 78 ($^\circ$F)

Over-fire (OF) air supply temperature[a] (TOF) = 71 ($^\circ$F)

[a] : OF air temperature is measured before entrance to the Biomass Combustion Unit (BCU). This is not the actual supply temperature. It was not feasible to measure the actual OF supply air (heated as it travels down the OF tube inside the BCU) because of the difficulty of thermocouple placement and lifespan in the harsh combustion gas environment.

COMBUSTION GAS DATA

(From Enerac Gas Analysis Unit and Separate Temp. Probes)

Note : All data is given as the mean value first and the standard deviation second, separated by a colon. Example - "mean CO_2 value" : "standard deviation of mean CO_2"

- **Gas temperature** (T_g) = 1520.00 : 52.21 ($^\circ$F)

- **Carbon monoxide (CO)** = 90.10 : 298.30 (ppm)

- Oxygen (O_2) = 8.69 : 1.90 (% by dry volume)

- **Carbon dioxide** (CO_2) = 12.06 : 1.96 (% by dry volume)

- Hydrocarbons (HCs) = 5.87 : 21.04 (% by dry volume)

- **Oxides of Nitrogen** (NO_x) = 74.20 : 18.37 (ppm)

- Sulphur dioxide (SO_2) = 5.87 : 21.04 (ppm)

- Particulate in exhaust (PART.) = .0521 (grains/dscf)[a]

- Combustible in Particulate (COMB.) = 33.88 (% dry basis)

[a] : dscf = dry standard cubic foot ; grain = 1/7000th ounce; data are adjusted to 12% CO_2.

COMBUSTION TEST DATA

TEST # 8.1   FUEL CODE : 1

OBJECTIVE : One "block" (out of 15) of the experimental

matrix to find optimal firing condition as a function of

excess air and under fire air for fuel #1.

Length of run = 60 (minutes)

FUEL AND AIR PARAMETERS (CONSTANT FOR TEST)

Fuel feedrate 1 (FF1) = 4.114 (lb/hr-dry basis)

Air/Fuel Ratio (A/F) = 6.265 (lb-dry air/lb-dry fuel)

Fuel feedrate 2 (FF2) = 36893.46 (Btu/hr)

Excess Air (%EA) percent = 87.23

Under fire air percent (%UF) = 20.00

Under-fire (UF) air supply temperature (TUF) = 76 (°F)

Over-fire (OF) air supply temperature[a] (TOF) = 68 (°F)

[a] : OF air temperature is measured before entrance to the
Biomass Combustion Unit (BCU). This is not the actual
supply temperature. It was not feasible to measure the
actual OF supply air (heated as it travels down the OF tube
inside the BCU) because of the difficulty of thermocouple
placement and lifespan in the harsh combustion gas
environment.

COMBUSTION GAS DATA

(From Enerac Gas Analysis Unit and Separate Temp. Probes)

Note : All data is given as the mean value first and the standard deviation second, separated by a colon. Example – "mean CO_2 value" : "standard deviation of mean CO_2"

- **Gas temperature (T_g)** = 1248.92 : 38.97 ($^{\circ}$F)

- **Carbon monoxide (CO)** = 116.63 : 46.60 (ppm)

- Oxygen (O_2) = 12.08 : 1.80 (% by dry volume)

- **Carbon dioxide (CO_2)** = 8.69 : 1.82 (% by dry volume)

- Hydrocarbons (HCs) = 0.0 : 0.0 (% by dry volume)

- **Oxides of Nitrogen (NO_x)** = 49.00 : 12.04 (ppm)

- Sulphur dioxide (SO_2) = 0.0 : 0.0 (ppm)

- Particulate in exhaust (PART.) = .0638 (grains/dscf)[a]

- Combustible in Particulate (COMB.) = 38.35 (% dry basis)

[a] : dscf = dry standard cubic foot ; grain = 1/7000th ounce; data are adjusted to 12% CO_2.

COMBUSTION TEST DATA

TEST # 8.2   <u>FUEL CODE</u> : 1

<u>OBJECTIVE</u> : One "block" (out of 15) of the experimental matrix to find optimal firing condition as a function of excess air and under fire air for fuel #1.

Length of run = 60 (minutes)

FUEL AND AIR PARAMETERS (CONSTANT FOR TEST)

Fuel feedrate 1 (FF1) = 4.114 (lb/hr-dry basis)

Air/Fuel Ratio (A/F) = 6.265 (lb-dry air/lb-dry fuel)

Fuel feedrate 2 (FF2) = 36893.46 (Btu/hr)

Excess Air (%EA) percent = 87.23

Under fire air percent (%UF) = 30.00

Under-fire (UF) air supply temperature (TUF) = 74 ($^\circ$F)

Over-fire (OF) air supply temperature[a] (TOF) = 68 ($^\circ$F)

[a] : OF air temperature is measured before entrance to the Biomass Combustion Unit (BCU). This is not the actual supply temperature. It was not feasible to measure the actual OF supply air (heated as it travels down the OF tube inside the BCU) because of the difficulty of thermocouple placement and lifespan in the harsh combustion gas environment.

COMBUSTION GAS DATA

(From Enerac Gas Analysis Unit and Separate Temp. Probes)

Note : All data is given as the mean value first and the standard deviation second, separated by a colon. Example - "mean CO_2 value" : "standard deviation of mean CO_2"

- Gas temperature (T_g) = 1253.87 : 18.03 ($°F$)

- Carbon monoxide (CO) = 102.30 : 22.50 (ppm)

- Oxygen (O_2) = 12.36 : 1.18 (% by dry volume)

- Carbon dioxide (CO_2) = 8.37 : 1.06 (% by dry volume)

- Hydrocarbons (HCs) = 0.0 : 0.0 (% by dry volume)

- Oxides of Nitrogen (NO_x) = 47.23 : 5.25 (ppm)

- Sulphur dioxide (SO_2) = 0.0 : 0.0 (ppm)

- Particulate in exhaust (PART.) = .0494 (grains/dscf)[a]

- Combustible in Particulate (COMB.) = 38.00 (% dry basis)

[a] : dscf = dry standard cubic foot ; grain = 1/7000th ounce; data are adjusted to 12% CO_2.

COMBUSTION TEST DATA

TEST # 8.3   FUEL CODE : 1

OBJECTIVE : One "block" (out of 15) of the experimental matrix to find optimal firing condition as a function of excess air and under fire air for fuel #1.

Length of run = 60 (minutes)

FUEL AND AIR PARAMETERS (CONSTANT FOR TEST)

Fuel feedrate 1 (FF1) = 4.114 (lb/hr-dry basis)

Air/Fuel Ratio (A/F) = 6.265 (lb-dry air/lb-dry fuel)

Fuel feedrate 2 (FF2) = 36893.46 (Btu/hr)

Excess Air (%EA) percent = 87.23

Under fire air percent (%UF) = 12.60

Under-fire (UF) air supply temperature (TUF) = 82 (°F)

Over-fire (OF) air supply temperature[a] (TOF) = 68 (°F)

_____

[a] : OF air temperature is measured before entrance to the Biomass Combustion Unit (BCU). This is not the actual supply temperature. It was not feasible to measure the actual OF supply air (heated as it travels down the OF tube inside the BCU) because of the difficulty of thermocouple placement and lifespan in the harsh combustion gas environment.

COMBUSTION GAS DATA

(From Enerac Gas Analysis Unit and Separate Temp. Probes)

Note : All data is given as the mean value first and the standard deviation second, separated by a colon. Example − "mean CO_2 value" : "standard deviation of mean CO_2"

- Gas temperature (T_g) = 1273.57 : 14.76 (°F)

- Carbon monoxide (CO) = 122.23 : 24.36 (ppm)

- Oxygen (O_2) = 13.19 : 0.67 (% by dry volume)

- Carbon dioxide (CO_2) = 7.57 : 0.76 (% by dry volume)

- Hydrocarbons (HCs) = 0.0 : 0.0 (% by dry volume)

- Oxides of Nitrogen (NO_x) = 42.70 : 2.87 (ppm)

- Sulphur dioxide (SO_2) = 0.0 : 0.0 (ppm)

- Particulate in exhaust (PART.) = .0328 (grains/dscf)[a]

- Combustible in Particulate (COMB.) = 38.69 (% dry basis)

[a] : dscf = dry standard cubic foot ; grain = 1/7000th ounce; data are adjusted to 12% CO_2.

COMBUSTION TEST DATA

TEST # 8.4   FUEL CODE : 1

OBJECTIVE : One "block" (out of 15) of the experimental
matrix to find optimal firing condition as a function of
excess air and under fire air for fuel #1.

Length of run = 60 (minutes)

FUEL AND AIR PARAMETERS (CONSTANT FOR TEST)

Fuel feedrate 1 (FF1) = 4.114 (lb/hr-dry basis)

Air/Fuel Ratio (A/F) = 6.265 (lb-dry air/lb-dry fuel)

Fuel feedrate 2 (FF2) = 36893.46 (Btu/hr)

Excess Air (%EA) percent = 87.23

Under fire air percent (%UF) = 50.00

Under-fire (UF) air supply temperature (TUF) = 74 ($^\circ$F)

Over-fire (OF) air supply temperature[a] (TOF) = 71 ($^\circ$F)

[a] : OF air temperature is measured before entrance to the
Biomass Combustion Unit (BCU). This is not the actual
supply temperature. It was not feasible to measure the
actual OF supply air (heated as it travels down the OF tube
inside the BCU) because of the difficulty of thermocouple
placement and lifespan in the harsh combustion gas
environment.

COMBUSTION GAS DATA

(From Enerac Gas Analysis Unit and Separate Temp. Probes)

Note : All data is given as the mean value first and the standard deviation second, separated by a colon. Example - "mean CO_2 value" : "standard deviation of mean CO_2"

- Gas temperature (T_g)   =   1319.38 : 12.04 ($^\circ$F)

- Carbon monoxide (CO)   =   54.90 : 13.13 (ppm)

- Oxygen (O_2)   =   12.95 : 1.17 (% by dry volume)

- Carbon dioxide (CO_2)   =   7.87 : 1.04 (% by dry volume)

- Hydrocarbons (HCs)   =   0.0 : 0.0 (% by dry volume)

- Oxides of Nitrogen (NO_x)   =   44.67 : 5.52 (ppm)

- Sulphur dioxide (SO_2)   =   0.0 : 0.0 (ppm)

- Particulate in exhaust (PART.)   =   .0741 (grains/dscf)[a]

- Combustible in Particulate (COMB.)   =   36.57 (% dry basis)

[a] : dscf = dry standard cubic foot ; grain = 1/7000th ounce; data are adjusted to 12% CO_2.

COMBUSTION TEST DATA

TEST # 8.5   FUEL CODE : 1

OBJECTIVE : One "block" (out of 15) of the experimental matrix to find optimal firing condition as a function of excess air and under fire air for fuel #1.

Length of run = 60 (minutes)

FUEL AND AIR PARAMETERS (CONSTANT FOR TEST)

Fuel feedrate 1 (FF1) = 4.114 (lb/hr-dry basis)

Air/Fuel Ratio (A/F) = 6.265 (lb-dry air/lb-dry fuel)

Fuel feedrate 2 (FF2) = 36893.46 (Btu/hr)

Excess Air (%EA) percent = 87.23

Under fire air percent (%UF) = 40.00

Under-fire (UF) air supply temperature (TUF) = 74 ($^\circ$F)

Over-fire (OF) air supply temperature^a (TOF) = 69 ($^\circ$F)

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^{a} : OF air temperature is measured before entrance to the Biomass Combustion Unit (BCU). This is not the actual supply temperature. It was not feasible to measure the actual OF supply air (heated as it travels down the OF tube inside the BCU) because of the difficulty of thermocouple placement and lifespan in the harsh combustion gas environment.

COMBUSTION GAS DATA

(From Enerac Gas Analysis Unit and Separate Temp. Probes)

Note : All data is given as the mean value first and the standard deviation second, separated by a colon. Example - "mean CO_2 value" : "standard deviation of mean CO_2"

- Gas temperature (T_g) = 1303.73 : 32.39 ($^\circ$F)

- Carbon monoxide (CO) = 65.93 : 22.52 (ppm)

- Oxygen (O_2) = 13.39 : 1.21 (% by dry volume)

- Carbon dioxide (CO_2) = 7.35 : 1.12 (% by dry volume)

- Hydrocarbons (HCs) = 0.0 : 0.0 (% by dry volume)

- Oxides of Nitrogen (NO_x) = 40.90 : 6.27 (ppm)

- Sulphur dioxide (SO_2) = 0.0 : 0.0 (ppm)

- Particulate in exhaust (PART.) = .0521 (grains/dscf)[a]

- Combustible in Particulate (COMB.) = 33.88 (% dry basis)

[a] : dscf = dry standard cubic foot ; grain = 1/7000th ounce; data are adjusted to 12% CO_2.

COMBUSTION TEST DATA

TEST # 9.1   FUEL CODE : 1

OBJECTIVE : One "block" (out of 15) of the experimental matrix to find optimal firing condition as a function of excess air and under fire air for fuel #1.

Length of run = 60 (minutes)

FUEL AND AIR PARAMETERS (CONSTANT FOR TEST)

Fuel feedrate 1 (FF1) = 4.083 (lb/hr-dry basis)

Air/Fuel Ratio (A/F) = 6.265 (lb-dry air/lb-dry fuel)

Fuel feedrate 2 (FF2) = 36621.94 (Btu/hr)

Excess Air (%EA) percent = 20.80

Under fire air percent (%UF) = 20.00

Under-fire (UF) air supply temperature (TUF) = 75 (°F)

Over-fire (OF) air supply temperature[a] (TOF) = 66 (°F)

[a] : OF air temperature is measured before entrance to the Biomass Combustion Unit (BCU). This is not the actual supply temperature. It was not feasible to measure the actual OF supply air (heated as it travels down the OF tube inside the BCU) because of the difficulty of thermocouple placement and lifespan in the harsh combustion gas environment.

COMBUSTION GAS DATA

(From Enerac Gas Analysis Unit and Separate Temp. Probes)

Note : All data is given as the mean value first and the standard deviation second, separated by a colon. Example – "mean CO_2 value" : "standard deviation of mean CO_2"

- **Gas temperature** (T_g) = 1331.83 : 23.00 ($^\circ$F)

- **Carbon monoxide (CO)** = 57.73 : 5.63 (ppm)

- Oxygen (O_2) = 12.53 : 1.03 (% by dry volume)

- **Carbon dioxide** (CO_2) = 8.34 : 0.87 (% by dry volume)

- Hydrocarbons (HCs) = 0.0 : 0.0 (% by dry volume)

- **Oxides of Nitrogen** (NO_x) = 46.23 : 7.08 (ppm)

- Sulphur dioxide (SO_2) = 0.0 : 0.0 (ppm)

- Particulate in exhaust (PART.) = .0393 (grains/dscf)[a]

- Combustible in Particulate (COMB.) = 33.43 (% dry basis)

[a] : dscf = dry standard cubic foot ; grain = 1/7000th ounce; data are adjusted to 12% CO_2.

COMBUSTION TEST DATA

TEST # 9.2   FUEL CODE : 1

OBJECTIVE : One "block" (out of 15) of the experimental
matrix to find optimal firing condition as a function of
excess air and under fire air for fuel #1.

Length of run = 60 (minutes)

FUEL AND AIR PARAMETERS (CONSTANT FOR TEST)

Fuel feedrate 1 (FF1)   =   4.083 (lb/hr-dry basis)

Air/Fuel Ratio (A/F)   =   6.265 (lb-dry air/lb-dry fuel)

Fuel feedrate 2 (FF2)   =   36621.94 (Btu/hr)

Excess Air (%EA) percent =   20.80

Under fire air percent (%UF) =   40.00

Under-fire (UF) air supply temperature (TUF) =   75 ($^\circ$F)

Over-fire (OF) air supply temperature[a] (TOF) =   70 ($^\circ$F)

[a] : OF air temperature is measured before entrance to the
Biomass Combustion Unit (BCU). This is not the actual
supply temperature. It was not feasible to measure the
actual OF supply air (heated as it travels down the OF tube
inside the BCU) because of the difficulty of thermocouple
placement and lifespan in the harsh combustion gas
environment.

COMBUSTION GAS DATA

(From Enerac Gas Analysis Unit and Separate Temp. Probes)

Note : All data is given as the mean value first and the standard deviation second, separated by a colon. Example - "mean CO_2 value" : "standard deviation of mean CO_2"

- **Gas temperature (T_g)** = 1425.93 : 25.24 (°F)

- **Carbon monoxide (CO)** = 128.37 : 186.70 (ppm)

- Oxygen (O_2) = 12.31 : 0.83 (% by dry volume)

- **Carbon dioxide (CO_2)** = 8.34 : 0.85 (% by dry volume)

- Hydrocarbons (HCs) = 0.0 : 0.0 (% by dry volume)

- **Oxides of Nitrogen (NO_x)** = 52.27 : 5.48 (ppm)

- Sulphur dioxide (SO_2) = 0.0 : 0.0 (ppm)

- Particulate in exhaust (PART.) = .0747 (grains/dscf)[a]

- Combustible in Particulate (COMB.) = 36.52 (% dry basis)

[a] : dscf = dry standard cubic foot ; grain = 1/7000th ounce; data are adjusted to 12% CO_2.

COMBUSTION TEST DATA

TEST # 9.3   FUEL CODE : 1

OBJECTIVE : One "block" (out of 15) of the experimental
matrix to find optimal firing condition as a function of
excess air and under fire air for fuel #1.

Length of run = 60 (minutes)

FUEL AND AIR PARAMETERS (CONSTANT FOR TEST)

Fuel feedrate 1 (FF1) = 4.083 (lb/hr-dry basis)

Air/Fuel Ratio (A/F) = 6.265 (lb-dry air/lb-dry fuel)

Fuel feedrate 2 (FF2) = 36621.94 (Btu/hr)

Excess Air (%EA) percent = 20.80

Under fire air percent (%UF) = 50.00

Under-fire (UF) air supply temperature (TUF) = 76 ($^\circ$F)

Over-fire (OF) air supply temperature[a] (TOF) = 73 ($^\circ$F)

[a] : OF air temperature is measured before entrance to the
Biomass Combustion Unit (BCU). This is not the actual
supply temperature. It was not feasible to measure the
actual OF supply air (heated as it travels down the OF tube
inside the BCU) because of the difficulty of thermocouple
placement and lifespan in the harsh combustion gas
environment.

COMBUSTION GAS DATA

(From Enerac Gas Analysis Unit and Separate Temp. Probes)

Note : All data is given as the mean value first and the standard deviation second, separated by a colon. Example - "mean CO_2 value" : "standard deviation of mean CO_2"

- **Gas temperature (T_g)** = 1481.13 : 18.47 ($^\circ$F)

- **Carbon monoxide (CO)** = 258.17 : 372.64 (ppm)

- Oxygen (O_2) = 11.05 : 1.04 (% by dry volume)

- **Carbon dioxide (CO_2)** = 9.75 : 1.02 (% by dry volume)

- Hydrocarbons (HCs) = 0.05 : 0.19 (% by dry volume)

- **Oxides of Nitrogen (NO_x)** = 61.63 : 5.54 (ppm)

- Sulphur dioxide (SO_2) = 0.0 : 0.0 (ppm)

- Particulate in exhaust (PART.) = .0798 (grains/dscf)[a]

- Combustible in Particulate (COMB.) = 37.03 (% dry basis)

[a] : dscf = dry standard cubic foot ; grain = 1/7000th ounce; data are adjusted to 12% CO_2.

COMBUSTION TEST DATA

TEST # 9.4   FUEL CODE : 1

OBJECTIVE : One "block" (out of 15) of the experimental

matrix to find optimal firing condition as a function of

excess air and under fire air for fuel #1.

Length of run = 60 (minutes)

FUEL AND AIR PARAMETERS (CONSTANT FOR TEST)

Fuel feedrate 1 (FF1)   =   4.083 (lb/hr-dry basis)

Air/Fuel Ratio (A/F) =   6.265 (lb-dry air/lb-dry fuel)

Fuel feedrate 2 (FF2) =   36621.94 (Btu/hr)

Excess Air (%EA) percent =   20.80

Under fire air percent (%UF) =   12.60

Under-fire (UF) air supply temperature (TUF) = 87 (°F)

Over-fire (OF) air supply temperature* (TOF) = 72 (°F)

* : OF air temperature is measured before entrance to the
Biomass Combustion Unit (BCU). This is not the actual
supply temperature. It was not feasible to measure the
actual OF supply air (heated as it travels down the OF tube
inside the BCU) because of the difficulty of thermocouple
placement and lifespan in the harsh combustion gas
environment.

COMBUSTION GAS DATA

(From Enerac Gas Analysis Unit and Separate Temp. Probes)

Note : All data is given as the mean value first and the standard deviation second, separated by a colon. Example - "mean CO_2 value" : "standard deviation of mean CO_2"

- Gas temperature (**T_g**)   =   1510.81 : 22.35 (°F)

- Carbon monoxide (**CO**)   =   54.27 : 172.81 (ppm)

- Oxygen (O_2)   =   11.29 : .95 (% by dry volume)

- Carbon dioxide (**CO_2**)   =   9.47 : 0.91 (% by dry volume)

- Hydrocarbons (HCs)   =   0.02 : 0.10 (% by dry volume)

- Oxides of Nitrogen (**NO_x**)   =   64.77 : 5.73 (ppm)

- Sulphur dioxide (SO_2)   =   0.0 : 0.0 (ppm)

- Particulate in exhaust (PART.)   =   .0264 (grains/dscf)[a]

- Combustible in Particulate (COMB.)   =   22.04 (% dry basis)

[a] : dscf = dry standard cubic foot ; grain = 1/7000th ounce; data are adjusted to 12% CO_2.

COMBUSTION TEST DATA

TEST # 9.5   FUEL CODE : 1

OBJECTIVE : One "block" (out of 15) of the experimental

matrix to find optimal firing condition as a function of

excess air and under fire air for fuel #1.

Length of run = 60 (minutes)

FUEL AND AIR PARAMETERS (CONSTANT FOR TEST)

Fuel feedrate 1 (FF1) = 4.083 (lb/hr-dry basis)

Air/Fuel Ratio (A/F) = 6.265 (lb-dry air/lb-dry fuel)

Fuel feedrate 2 (FF2) = 36621.94 (Btu/hr)

Excess Air (%EA) percent = 20.80

Under fire air percent (%UF) = 30.00

Under-fire (UF) air supply temperature (TUF) = 83 ($^\circ$F)

Over-fire (OF) air supply temperature^a (TOF) = 74 ($^\circ$F)

^{a} : OF air temperature is measured before entrance to the
Biomass Combustion Unit (BCU). This is not the actual
supply temperature. It was not feasible to measure the
actual OF supply air (heated as it travels down the OF tube
inside the BCU) because of the difficulty of thermocouple
placement and lifespan in the harsh combustion gas
environment.

COMBUSTION GAS DATA

(From Enerac Gas Analysis Unit and Separate Temp. Probes)

Note : All data is given as the mean value first and the standard deviation second, separated by a colon. Example - "mean CO_2 value" : "standard deviation of mean CO_2"

- Gas temperature (T_g) = 1565.61 : 14.16 ($^\circ$F)

- Carbon monoxide (CO) = 71.43 : 208.70 (ppm)

- Oxygen (O_2) = 10.27 : .75 (% by dry volume)

- Carbon dioxide (CO_2) = 10.50 : 0.69 (% by dry volume)

- Hydrocarbons (HCs) = 0.01 : 0.05 (% by dry volume)

- Oxides of Nitrogen (NO_x) = 68.23 : 5.54 (ppm)

- Sulphur dioxide (SO_2) = 0.0 : 0.0 (ppm)

- Particulate in exhaust (PART.) = .0854 (grains/dscf)[a]

- Combustible in Particulate (COMB.) = 33.53 (% dry basis)

[a] : dscf = dry standard cubic foot ; grain = 1/7000th ounce; data are adjusted to 12% CO_2.

COMBUSTION TEST DATA

TEST # 11.1   FUEL CODE : 5

OBJECTIVE : To examine the combustion efficiency for a number of woody biomass fuels (nine fuels in all, including test 6.3 from the optimal firing condition test on fuel #1.

Length of run = 30 (minutes)

FUEL AND AIR PARAMETERS (CONSTANT FOR TEST)

Fuel feedrate 1 (FF1)   =   4.590 (lb/hr-dry basis)

Air/Fuel Ratio (A/F)   =   6.588 (lb-dry air/lb-dry fuel)

Fuel feedrate 2 (FF2)   =   42158.44 (Btu/hr)

Excess Air (%EA) percent =   29.18

Under fire air percent (%UF) =   30.00

Under-fire (UF) air supply temperature (TUF) = 73 (°F)

Over-fire (OF) air supply temperature° (TOF) = 67 (°F)

" : OF air temperature is measured before entrance to the Biomass Combustion Unit (BCU). This is not the actual supply temperature. It was not feasible to measure the actual OF supply air (heated as it travels down the OF tube inside the BCU) because of the difficulty of thermocouple placement and lifespan in the harsh combustion gas environment.

COMBUSTION GAS DATA

(From Enerac Gas Analysis Unit and Separate Temp. Probes)

Note : All data is given as the mean value first and the standard deviation second, separated by a colon. Example - "mean CO_2 value" : "standard deviation of mean CO_2"

- Gas temperature (T_g)   =   1376.46 : 13.22 ($^\circ$F)

- Carbon monoxide (CO)   =   186.13 : 16.88 (ppm)

- Oxygen (O_2)   =   8.25 : .93 (% by dry volume)

- Carbon dioxide (CO_2)   =   12.44 : 0.85 (% by dry volume)

- Hydrocarbons (HCs)   =   0.0 : 0.0 (% by dry volume)

- Oxides of Nitrogen (NO_x)   =   194.67 : 40.74 (ppm)

- Sulphur dioxide (SO_2)   =   0.0 : 0.0 (ppm)

- Particulate in exhaust (PART.)   =   .0751 (grains/dscf)[a]

- Combustible in Particulate (COMB.)   =   89.59 (% dry basis)

[a] : dscf = dry standard cubic foot ; grain = 1/7000th ounce; data are adjusted to 12% CO_2.

COMBUSTION TEST DATA

TEST # 11.2   FUEL CODE : 2

OBJECTIVE : To examine the combustion efficiency for a

number of woody biomass fuels (nine fuels in all, including

test 6.3 from the optimal firing condition test on fuel #1.

Length of run = 30 (minutes)

FUEL AND AIR PARAMETERS (CONSTANT FOR TEST)

Fuel feedrate 1 (FF1) = 3.943 (lb/hr-dry basis)

Air/Fuel Ratio (A/F) = 6.197 (lb-dry air/lb-dry fuel)

Fuel feedrate 2 (FF2) = 35208.12 (Btu/hr)

Excess Air (%EA) percent = 50.38

Under fire air percent (%UF) = 30.00

Under-fire (UF) air supply temperature (TUF) = 74 ($^\circ$F)

Over-fire (OF) air supply temperature^a (TOF) = 69 ($^\circ$F)

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^{a} : OF air temperature is measured before entrance to the
Biomass Combustion Unit (BCU). This is not the actual
supply temperature. It was not feasible to measure the
actual OF supply air (heated as it travels down the OF tube
inside the BCU) because of the difficulty of thermocouple
placement and lifespan in the harsh combustion gas
environment.

COMBUSTION GAS DATA

(From Enerac Gas Analysis Unit and Separate Temp. Probes)

Note : All data is given as the mean value first and the standard deviation second, separated by a colon. Example – "mean CO_2 value" : "standard deviation of mean CO_2"

- Gas temperature (T_g)   =   1354.29 : 22.78 ($^\circ$F)

- Carbon monoxide (CO)   =   114.60 : 10.89 (ppm)

- Oxygen (O_2)   =   9.52 : 1.81 (% by dry volume)

- Carbon dioxide (CO_2)   =   11.21 : 1.79 (% by dry volume)

- Hydrocarbons (HCs)   =   0.0 : 0.0 (% by dry volume)

- Oxides of Nitrogen (NO_x)   =   130.30 : 18.39 (ppm)

- Sulphur dioxide (SO_2)   =   0.0 : 0.0 (ppm)

- Particulate in exhaust (PART.)   =   .0898 (grains/dscf)[a]

- Combustible in Particulate (COMB.)   =   7.080 (% dry basis)

[a] : dscf = dry standard cubic foot ; grain = 1/7000th ounce; data are adjusted to 12% CO_2.

COMBUSTION TEST DATA

TEST # 11.3   FUEL CODE : 6

OBJECTIVE : To examine the combustion efficiency for a number of woody biomass fuels (nine fuels in all, including test 6.3 from the optimal firing condition test on fuel #1.

Length of run = 30 (minutes)

FUEL AND AIR PARAMETERS (CONSTANT FOR TEST)

Fuel feedrate 1 (FF1) = 4.456 (lb/hr-dry basis)

Air/Fuel Ratio (A/F) = 6.339 (lb-dry air/lb-dry fuel)

Fuel feedrate 2 (FF2) = 40735.10 (Btu/hr)

Excess Air (%EA) percent = 33.06

Under fire air percent (%UF) = 30.00

Under-fire (UF) air supply temperature (TUF) = 76 (°F)

Over-fire (OF) air supply temperature° (TOF) = 71 (°F)

" : OF air temperature is measured before entrance to the Biomass Combustion Unit (BCU). This is not the actual supply temperature. It was not feasible to measure the actual OF supply air (heated as it travels down the OF tube inside the BCU) because of the difficulty of thermocouple placement and lifespan in the harsh combustion gas environment.

COMBUSTION GAS DATA

(From Enerac Gas Analysis Unit and Separate Temp. Probes)

Note : All data is given as the mean value first and the standard deviation second, separated by a colon. Example - "mean CO_2 value" : "standard deviation of mean CO_2"

- **Gas temperature (T_g)** = 1460.91 : 21.61 ($^\circ$F)

- **Carbon monoxide (CO)** = 188.20 : 157.48 (ppm)

- Oxygen (O_2) = 7.99 : 1.38 (% by dry volume)

- **Carbon dioxide (CO_2)** = 12.73 : 1.37 (% by dry volume)

- Hydrocarbons (HCs) = 0.0 : 0.0 (% by dry volume)

- **Oxides of Nitrogen (NO_x)** = 203.57 : 22.52 (ppm)

- Sulphur dioxide (SO_2) = 0.0 : 0.0 (ppm)

- Particulate in exhaust (PART.) = .0623 (grains/dscf)[a]

- Combustible in Particulate (COMB.) = 3.830 (% dry basis)

[a] : dscf = dry standard cubic foot ; grain = 1/7000th ounce; data are adjusted to 12% CO_2.

COMBUSTION TEST DATA

TEST # 11.4   FUEL CODE : 7

OBJECTIVE : To examine the combustion efficiency for a
number of woody biomass fuels (nine fuels in all, including
test 6.3 from the optimal firing condition test on fuel #1.

Length of run = 30 (minutes)

FUEL AND AIR PARAMETERS (CONSTANT FOR TEST)

Fuel feedrate 1 (FF1) = 3.890 (lb/hr-dry basis)

Air/Fuel Ratio (A/F) = 6.005 (lb-dry air/lb-dry fuel)

Fuel feedrate 2 (FF2) = 33798.29 (Btu/hr)

Excess Air (%EA) percent = 52.42

Under fire air percent (%UF) = 30.00

Under-fire (UF) air supply temperature (TUF) = 78 (°F)

Over-fire (OF) air supply temperature[a] (TOF) = 72 (°F)

[a] : OF air temperature is measured before entrance to the
Biomass Combustion Unit (BCU). This is not the actual
supply temperature. It was not feasible to measure the
actual OF supply air (heated as it travels down the OF tube
inside the BCU) because of the difficulty of thermocouple
placement and lifespan in the harsh combustion gas
environment.

COMBUSTION GAS DATA

(From Enerac Gas Analysis Unit and Separate Temp. Probes)

Note : All data is given as the mean value first and the standard deviation second, separated by a colon. Example - "mean CO_2 value" : "standard deviation of mean CO_2."

- Gas temperature (T_g) = 1337.48 : 31.58 (°F)

- Carbon monoxide (CO) = 153.07 : 15.94 (ppm)

- Oxygen (O_2) = 10.68 : 1.54 (% by dry volume)

- Carbon dioxide (CO_2) = 10.11 : 1.48 (% by dry volume)

- Hydrocarbons (HCs) = 0.0 : 0.0 (% by dry volume)

- Oxides of Nitrogen (NO_x) = 214.97 : 34.42 (ppm)

- Sulphur dioxide (SO_2) = 0.0 : 0.0 (ppm)

- Particulate in exhaust (PART.) = .0372 (grains/dscf)[a]

- Combustible in Particulate (COMB.) = 1.700 (% dry basis)

[a] : dscf = dry standard cubic foot ; grain = 1/7000th ounce; data are adjusted to 12% CO_2.

COMBUSTION TEST DATA

TEST # 11.5   FUEL CODE : 4

OBJECTIVE : To examine the combustion efficiency for a number of woody biomass fuels (nine fuels in all, including test 6.3 from the optimal firing condition test on fuel #1.

Length of run = 30 (minutes)

FUEL AND AIR PARAMETERS (CONSTANT FOR TEST)

Fuel feedrate 1 (FF1) = 4.606 (lb/hr-dry basis)

Air/Fuel Ratio (A/F) = 6.187 (lb-dry air/lb-dry fuel)

Fuel feedrate 2 (FF2) = 40469.55 (Btu/hr)

Excess Air (%EA) percent = 28.73

Under fire air percent (%UF) = 30.00

Under-fire (UF) air supply temperature (TUF) = 77 (°F)

Over-fire (OF) air supply temperature[a] (TOF) = 73 (°F)

[a] : OF air temperature is measured before entrance to the Biomass Combustion Unit (BCU). This is not the actual supply temperature. It was not feasible to measure the actual OF supply air (heated as it travels down the OF tube inside the BCU) because of the difficulty of thermocouple placement and lifespan in the harsh combustion gas environment.

COMBUSTION GAS DATA

(From Enerac Gas Analysis Unit and Separate Temp. Probes)

Note : All data is given as the mean value first and the standard deviation second, separated by a colon. Example - "mean CO_2 value" : "standard deviation of mean CO_2"

- Gas temperature (T_g) = 1482.34 : 27.48 ($°F$)

- Carbon monoxide (CO) = 134.67 : 192.91 (ppm)

- Oxygen (O_2) = 7.77 : 1.49 (% by dry volume)

- Carbon dioxide (CO_2) = 12.50 : 2.77 (% by dry volume)

- Hydrocarbons (HCs) = 1.70 : 9.16 (% by dry volume)

- Oxides of Nitrogen (NO_x) = 125.43 : 28.14 (ppm)

- Sulphur dioxide (SO_2) = 0.0 : 0.0 (ppm)

- Particulate in exhaust (PART.) = .7045 (grains/dscf)[a]

- Combustible in Particulate (COMB.) = 00.19 (% dry basis)

[a] : dscf = dry standard cubic foot ; grain = 1/7000th ounce; data are adjusted to 12% CO_2.

COMBUSTION TEST DATA

TEST # 11.6   FUEL CODE : 3

OBJECTIVE : To examine the combustion efficiency for a number of woody biomass fuels (nine fuels in all, including test 6.3 from the optimal firing condition test on fuel #1.

Length of run = 30 (minutes)

FUEL AND AIR PARAMETERS (CONSTANT FOR TEST)

Fuel feedrate 1 (FF1) = 3.892 (lb/hr-dry basis)

Air/Fuel Ratio (A/F) = 6.549 (lb-dry air/lb-dry fuel)

Fuel feedrate 2 (FF2) = 34912.21 (Btu/hr)

Excess Air (%EA) percent = 52.34

Under fire air percent (%UF) = 30.00

Under-fire (UF) air supply temperature (TUF) = 78 ($^\circ$F)

Over-fire (OF) air supply temperature[a] (TOF) = 73 ($^\circ$F)

[a] : OF air temperature is measured before entrance to the Biomass Combustion Unit (BCU). This is not the actual supply temperature. It was not feasible to measure the actual OF supply air (heated as it travels down the OF tube inside the BCU) because of the difficulty of thermocouple placement and lifespan in the harsh combustion gas environment.

COMBUSTION GAS DATA

(From Enerac Gas Analysis Unit and Separate Temp. Probes)

<u>Note : All data is given as the mean value first and the standard deviation second, separated by a colon. Example - "mean CO_2 value" : "standard deviation of mean CO_2"</u>

- Gas temperature (T_g) = 1395.74 : 20.20 ($^\circ$F)

- Carbon monoxide (CO) = 92.83 : 10.20 (ppm)

- Oxygen (O_2) = 10.52 : 1.13 (% by dry volume)

- Carbon dioxide (CO_2) = 10.18 : 1.07 (% by dry volume)

- Hydrocarbons (HCs) = 0.00 : 0.00 (% by dry volume)

- Oxides of Nitrogen (NO_x) = 122.47 : 13.88 (ppm)

- Sulphur dioxide (SO_2) = 0.0 : 0.0 (ppm)

- Particulate in exhaust (PART.) = .0292 (grains/dscf)[a]

- Combustible in Particulate (COMB.) = 9.160 (% dry basis)

[a] : dscf = dry standard cubic foot ; grain = 1/7000th ounce; data are adjusted to 12% CO_2.

COMBUSTION TEST DATA

TEST # 11.7   FUEL CODE : 8

OBJECTIVE : To examine the combustion efficiency for a number of woody biomass fuels (nine fuels in all, including test 6.3 from the "Optimal Firing Condition Test" on fuel #1.

Length of run = 30 (minutes)

FUEL AND AIR PARAMETERS (CONSTANT FOR TEST)

Fuel feedrate 1 (FF1) = 4.383 (lb/hr-dry basis)

Air/Fuel Ratio (A/F) = 6.672 (lb-dry air/lb-dry fuel)

Fuel feedrate 2 (FF2) = 37437.80 (Btu/hr)

Excess Air (%EA) percent = 47.04

Under fire air percent (%UF) = 30.00

Under-fire (UF) air supply temperature (TUF) = 78 (°F)

Over-fire (OF) air supply temperature[a] (TOF) = 73 (°F)

[a] : OF air temperature is measured before entrance to the Biomass Combustion Unit (BCU). This is not the actual supply temperature. It was not feasible to measure the actual OF supply air (heated as it travels down the OF tube inside the BCU) because of the difficulty of thermocouple placement and lifespan in the harsh combustion gas environment.

COMBUSTION GAS DATA

(From Enerac Gas Analysis Unit and Separate Temp. Probes)

Note : All data is given as the mean value first and the standard deviation second, separated by a colon. Example – "mean CO_2 value" : "standard deviation of mean CO_2"

- Gas temperature (T_g) = 1448.46 : 13.40 ($^\circ$F)

- Carbon monoxide (CO) = 138.73 : 30.82 (ppm)

- Oxygen (O_2) = 9.81 : 0.87 (% by dry volume)

- Carbon dioxide (CO_2) = 10.94 : 0.92 (% by dry volume)

- Hydrocarbons (HCs) = 0.00 : 0.00 (% by dry volume)

- Oxides of Nitrogen (NO_x) = 153.80 : 16.46 (ppm)

- Sulphur dioxide (SO_2) = 0.2 : 1.08 (ppm)

- Particulate in exhaust (PART.) = .6311 (grains/dscf)[a]

- Combustible in Particulate (COMB.) = 00.98 (% dry basis)

[a] : dscf = dry standard cubic foot ; grain = 1/7000th ounce; data are adjusted to 12% CO_2.

COMBUSTION TEST DATA

TEST # 11.8   FUEL CODE : 9

OBJECTIVE : To examine the combustion efficiency for a number of woody biomass fuels (nine fuels in all, including test 6.3 from the "Optimal Firing Condition Test" on fuel #1.

 Length of run = 30 (minutes)

FUEL AND AIR PARAMETERS (CONSTANT FOR TEST)

Fuel feedrate 1 (FF1) = 4.118 (lb/hr-dry basis)

Air/Fuel Ratio (A/F) = 6.152 (lb-dry air/lb-dry fuel)

Fuel feedrate 2 (FF2) = 31019.22 (Btu/hr)

Excess Air (%EA) percent = 68.21

Under fire air percent (%UF) = 30.00

Under-fire (UF) air supply temperature (TUF) = 79 ($^\circ$F)

Over-fire (OF) air supply temperature[a] (TOF) = 73 ($^\circ$F)

[a] : OF air temperature is measured before entrance to the Biomass Combustion Unit (BCU). This is not the actual supply temperature. It was not feasible to measure the actual OF supply air (heated as it travels down the OF tube inside the BCU) because of the difficulty of thermocouple placement and lifespan in the harsh combustion gas environment.

COMBUSTION GAS DATA

(From Enerac Gas Analysis Unit and Separate Temp. Probes)

Note : All data is given as the mean value first and the standard deviation second, separated by a colon. Example - "mean CO_2 value" : "standard deviation of mean CO_2"

- Gas temperature (T_g) = 1348.10 : 46.58 ($^{\circ}$F)

- Carbon monoxide (CO) = 119.37 : 18.64 (ppm)

- Oxygen (O_2) = 11.34 : 2.73 (% by dry volume)

- Carbon dioxide (CO_2) = 9.39 : 2.62 (% by dry volume)

- Hydrocarbons (HCs) = 0.00 : 0.00 (% by dry volume)

- Oxides of Nitrogen (NO_x) = 165.10 : 50.95 (ppm)

- Sulphur dioxide (SO_2) = 0.0 : 0.0 (ppm)

- Particulate in exhaust (PART.) = .1678 (grains/dscf)[a]

- Combustible in Particulate (COMB.) = 5.090 (% dry basis)

[a] : dscf = dry standard cubic foot ; grain = 1/7000th ounce; data are adjusted to 12% CO_2.

COMBUSTION TEST DATA

TEST # 12.1   FUEL CODE : 1

OBJECTIVE : To analyze the effect of heating the under fire air on the combustion efficiency of selected pellet fuels. Fuels tested, by code : 1, 4, 2, 8, 9)

Length of run = 30 (minutes)

FUEL AND AIR PARAMETERS (CONSTANT FOR TEST)

Fuel feedrate 1 (FF1) = 3.848 (lb/hr-dry basis)

Air/Fuel Ratio (A/F) = 6.265 (lb-dry air/lb-dry fuel)

Fuel feedrate 2 (FF2) = 35346.57 (Btu/hr)

Excess Air (%EA) percent = 50.20

Under fire air percent (%UF) = 30.00

Under-fire (UF) air supply temperature (TUF) = 78 ($^\circ$F)

Over-fire (OF) air supply temperature^a (TOF) = 73 ($^\circ$F)

^{a} : OF air temperature is measured before entrance to the Biomass Combustion Unit (BCU). This is not the actual supply temperature. It was not feasible to measure the actual OF supply air (heated as it travels down the OF tube inside the BCU) because of the difficulty of thermocouple placement and lifespan in the harsh combustion gas environment.

COMBUSTION GAS DATA

(From Enerac Gas Analysis Unit and Separate Temp. Probes)

Note : All data is given as the mean value first and the standard deviation second, separated by a colon. Example - "mean CO_2 value" : "standard deviation of mean CO_2"

- Gas temperature (T_g) = 1247.63 : 19.06 ($°F$)

- Carbon monoxide (CO) = 123.67 : 16.26 (ppm)

- Oxygen (O_2) = 8.02 : 1.28 (% by dry volume)

- Carbon dioxide (CO_2) = 12.74 : 1.21 (% by dry volume)

- Hydrocarbons (HCs) = 0.00 : 0.00 (% by dry volume)

- Oxides of Nitrogen (NO_x) = 71.70 : 6.13 (ppm)

- Sulphur dioxide (SO_2) = 0.0 : 0.0 (ppm)

- Particulate in exhaust (PART.) = .0875 (grains/dscf)[a]

- Combustible in Particulate (COMB.) = 63.83 (% dry basis)

[a] : dscf = dry standard cubic foot ; grain = 1/7000th ounce; data are adjusted to 12% CO_2.

COMBUSTION TEST DATA

TEST # 12.2   FUEL CODE : 1

OBJECTIVE : To analyze the effect of <u>heating the under fire air</u> on the combustion efficiency of selected pellet fuels. Fuels tested, by code : 1, 4, 2, 8, 9)

 Length of run = 30 (minutes)

FUEL AND AIR PARAMETERS (CONSTANT FOR TEST)

Fuel feedrate 1 (FF1) = 3.848 (lb/hr-dry basis)

Air/Fuel Ratio (A/F) = 6.265 (lb-dry air/lb-dry fuel)

Fuel feedrate 2 (FF2) = 35346.57 (Btu/hr)

Excess Air (%EA) percent = 50.20

Under fire air percent (%UF) = 30.00

Under-fire (UF) air supply temperature (TUF) = 78 ($^\circ$F)

Over-fire (OF) air supply temperature^a (TOF) = 307 ($^\circ$F)

^{a} : OF air temperature is measured before entrance to the Biomass Combustion Unit (BCU). This is not the actual supply temperature. It was not feasible to measure the actual OF supply air (heated as it travels down the OF tube inside the BCU) because of the difficulty of thermocouple placement and lifespan in the harsh combustion gas environment.

COMBUSTION GAS DATA

(From Enerac Gas Analysis Unit and Separate Temp. Probes)

Note : All data is given as the mean value first and the

standard deviation second, separated by a colon. Example -

"mean CO_2 value" : "standard deviation of mean CO_2"

- Gas temperature (T_g) = 1280.43 : 15.89 ($°F$)

- Carbon monoxide (CO) = 71.63 : 9.90 (ppm)

- Oxygen (O_2) = 8.48 : 1.31 (% by dry volume)

- Carbon dioxide (CO_2) = 12.30 : 1.18 (% by dry volume)

- Hydrocarbons (HCs) = 0.00 : 0.00 (% by dry volume)

- Oxides of Nitrogen (NO_x) = 69.67 : 6.17 (ppm)

- Sulphur dioxide (SO_2) = 0.0 : 0.0 (ppm)

- Particulate in exhaust (PART.) = .0468 (grains/dscf)[a]

- Combustible in Particulate (COMB.) = 9.62 (% dry basis)

[a] : dscf = dry standard cubic foot ; grain = 1/7000th ounce;

data are adjusted to 12% CO_2.

COMBUSTION TEST DATA

TEST # 12.3   FUEL CODE : 4

OBJECTIVE : To analyze the effect of <u>heating the under fire air</u> on the combustion efficiency of selected pellet fuels. Fuels tested, by code : 1, 4, 2, 8, 9)

Length of run = 30 (minutes)

FUEL AND AIR PARAMETERS (CONSTANT FOR TEST)

Fuel feedrate 1 (FF1) = 4.977 (lb/hr-dry basis)

Air/Fuel Ratio (A/F) = 6.187 (lb-dry air/lb-dry fuel)

Fuel feedrate 2 (FF2) = 43729.33 (Btu/hr)

Excess Air (%EA) percent = 19.13

Under fire air percent (%UF) = 30.00

Under-fire (UF) air supply temperature (TUF) = 77 (°F)

Over-fire (OF) air supply temperature[a] (TOF) = 306 (°F)

[a] : OF air temperature is measured before entrance to the Biomass Combustion Unit (BCU). This is not the actual supply temperature. It was not feasible to measure the actual OF supply air (heated as it travels down the OF tube inside the BCU) because of the difficulty of thermocouple placement and lifespan in the harsh combustion gas environment.

COMBUSTION GAS DATA

(From Enerac Gas Analysis Unit and Separate Temp. Probes)

Note : All data is given as the mean value first and the standard deviation second, separated by a colon. Example - "mean CO_2 value" : "standard deviation of mean CO_2"

- Gas temperature (T_g) =   1469.99 : 30.85 ($^\circ$F)

- Carbon monoxide (CO)   =   315.18 : 640.11 (ppm)

- Oxygen (O_2) =   5.68 : 4.76 (% by dry volume)

- Carbon dioxide (CO_2) =   14.97 : 4.53 (% by dry volume)

- Hydrocarbons (HCs)   =   0.59 : 1.61 (% by dry volume)

- Oxides of Nitrogen (NO_x) =   136.83 : 40.27 (ppm)

- Sulphur dioxide (SO_2) =   0.40 : 1.47 (ppm)

- Particulate in exhaust (PART.)   =   .0782 (grains/dscf)[a]

- Combustible in Particulate (COMB.)   =   0.49 (% dry basis)

[a] : dscf = dry standard cubic foot ; grain = 1/7000th ounce; data are adjusted to 12% CO_2.

COMBUSTION TEST DATA

TEST # 12.4   FUEL CODE : 2

OBJECTIVE : To analyze the effect of heating the under fire
air on the combustion efficiency of selected pellet fuels.
Fuels tested, by code : 1, 4, 2, 8, 9)

Length of run = 30 (minutes)

FUEL AND AIR PARAMETERS (CONSTANT FOR TEST)

Fuel feedrate 1 (FF1) = 4.657 (lb/hr-dry basis)

Air/Fuel Ratio (A/F) = 6.197 (lb-dry air/lb-dry fuel)

Fuel feedrate 2 (FF2) = 41582.46 (Btu/hr)

Excess Air (%EA) percent = 27.32

Under fire air percent (%UF) = 30.00

Under-fire (UF) air supply temperature (TUF) = 76 ($^{\circ}$F)

Over-fire (OF) air supply temperature[a] (TOF) = 306 ($^{\circ}$F)

[a] : OF air temperature is measured before entrance to the
Biomass Combustion Unit (BCU). This is not the actual
supply temperature. It was not feasible to measure the
actual OF supply air (heated as it travels down the OF tube
inside the BCU) because of the difficulty of thermocouple
placement and lifespan in the harsh combustion gas
environment.

COMBUSTION GAS DATA

(From Enerac Gas Analysis Unit and Separate Temp. Probes)

Note : All data is given as the mean value first and the standard deviation second, separated by a colon. Example - "mean CO_2 value" : "standard deviation of mean CO_2"

- Gas temperature (T_g) = 1485.24 : 52.46 ($°F$)

- Carbon monoxide (CO) = 334.42 : 624.89 (ppm)

- Oxygen (O_2) = 9.42 : 6.34 (% by dry volume)

- Carbon dioxide (CO_2) = 11.70 : 5.74 (% by dry volume)

- Hydrocarbons (HCs) = 0.85 : 1.39 (% by dry volume)

- Oxides of Nitrogen (NO_x) = 128.90 : 62.89 (ppm)

- Sulphur dioxide (SO_2) = 0.40 : 1.50 (ppm)

- Particulate in exhaust (PART.) = .0575 (grains/dscf)[a]

- Combustible in Particulate (COMB.) = 6.14 (% dry basis)

[a] : dscf = dry standard cubic foot ; grain = 1/7000th ounce; data are adjusted to 12% CO_2.

COMBUSTION TEST DATA

<u>TEST #</u> 12.5   <u>FUEL CODE</u> : 8

<u>OBJECTIVE</u> : To analyze the effect of <u>heating the under fire</u>

<u>air</u> on the combustion efficiency of selected pellet fuels.

Fuels tested, by code : 1, 4, 2, 8, 9)

Length of run   =   30 (minutes)

<u>FUEL AND AIR PARAMETERS (CONSTANT FOR TEST)</u>

Fuel feedrate 1 (FF1)   =   4.971 (lb/hr-dry basis)

Air/Fuel Ratio (A/F)   =   6.672 (lb-dry air/lb-dry fuel)

Fuel feedrate 2 **(FF2)**   =   46150.23 (Btu/hr)

Excess Air **(%EA)** percent   =   19.28

Under fire air percent **(%UF)**   =   30.00

Under-fire (UF) air supply temperature (TUF)   =   77 ($^{\circ}$F)

Over-fire (OF) air supply temperature^a (TOF)   =   307 ($^{\circ}$F)

^{a} : OF air temperature is measured before entrance to the
Biomass Combustion Unit (BCU). This is not the actual
supply temperature. It was not feasible to measure the
actual OF supply air (heated as it travels down the OF tube
inside the BCU) because of the difficulty of thermocouple
placement and lifespan in the harsh combustion gas
environment.

COMBUSTION GAS DATA

(From Enerac Gas Analysis Unit and Separate Temp. Probes)

Note : All data is given as the mean value first and the standard deviation second, separated by a colon. Example - "mean CO_2 value" : "standard deviation of mean CO_2"

- Gas temperature (T_g)   =   1598.78 : 21.65 ($^\circ$F)

- Carbon monoxide (CO)   =   96.932 : 18.92 (ppm)

- Oxygen (O_2)   =   4.70 : 1.17 (% by dry volume)

- Carbon dioxide (CO_2)   =   15.94 : 1.13 (% by dry volume)

- Hydrocarbons (HCs)   =   0.00 : 0.00 (% by dry volume)

- Oxides of Nitrogen (NO_x)   =   191.80 : 17.52 (ppm)

- Sulphur dioxide (SO_2)   =   0.00 : 0.00 (ppm)

- Particulate in exhaust (PART.)   =   .7758 (grains/dscf)[a]

- Combustible in Particulate (COMB.)   =   0.35 (% dry basis)

[a] : dscf = dry standard cubic foot ; grain = 1/7000th ounce; data are adjusted to 12% CO_2.

COMBUSTION TEST DATA

TEST # 12.6   FUEL CODE : 9

OBJECTIVE : To analyze the effect of heating the under fire

air on the combustion efficiency of selected pellet fuels.

Fuels tested, by code : 1, 4, 2, 8, 9)

Length of run = 30 (minutes)

FUEL AND AIR PARAMETERS (CONSTANT FOR TEST)

Fuel feedrate 1 (FF1) = 4.413 (lb/hr-dry basis)

Air/Fuel Ratio (A/F) = 6.152 (lb-dry air/lb-dry fuel)

Fuel feedrate 2 (FF2) = 38830.61 (Btu/hr)

Excess Air (%EA) percent = 34.36

Under fire air percent (%UF) = 30.00

Under-fire (UF) air supply temperature (TUF) = 78 ($^{\circ}$F)

Over-fire (OF) air supply temperature^{a} (TOF) = 306 ($^{\circ}$F)

^{a} : OF air temperature is measured before entrance to the
Biomass Combustion Unit (BCU). This is not the actual
supply temperature. It was not feasible to measure the
actual OF supply air (heated as it travels down the OF tube
inside the BCU) because of the difficulty of thermocouple
placement and lifespan in the harsh combustion gas
environment.

COMBUSTION GAS DATA

(From Enerac Gas Analysis Unit and Separate Temp. Probes)

Note : All data is given as the mean value first and the standard deviation second, separated by a colon. Example - "mean CO_2 value" : "standard deviation of mean CO_2"

- **Gas temperature (T_q)** = 1483.39 : 16.77 ($^{\circ}$F)

- **Carbon monoxide (CO)** = 138.13 : 131.98 (ppm)

- Oxygen (O_2) = 5.21 : 1.73 (% by dry volume)

- **Carbon dioxide (CO_2)** = 15.45 : 1.72 (% by dry volume)

- Hydrocarbons (HCs) = 0.00 : 0.00 (% by dry volume)

- **Oxides of Nitrogen (NO_x)** = 237.07 : 37.30 (ppm)

- Sulphur dioxide (SO_2) = 0.00 : 0.00 (ppm)

- Particulate in exhaust (PART.) = .2486 (grains/dscf)[a]

- Combustible in Particulate (COMB.) = 0.05 (% dry basis)

[a] : dscf = dry standard cubic foot ; grain = 1/7000th ounce; data are adjusted to 12% CO_2.

APPENDIX   E

FUEL HOPPER FIGURE

FUEL HOPPER

FUEL METERING DRUM
(VARIABLE R.P.M.)

MOTOR

FEED TUBE WITH HORIZONTAL
FUEL AUGER

MOTOR

30.00   23.25
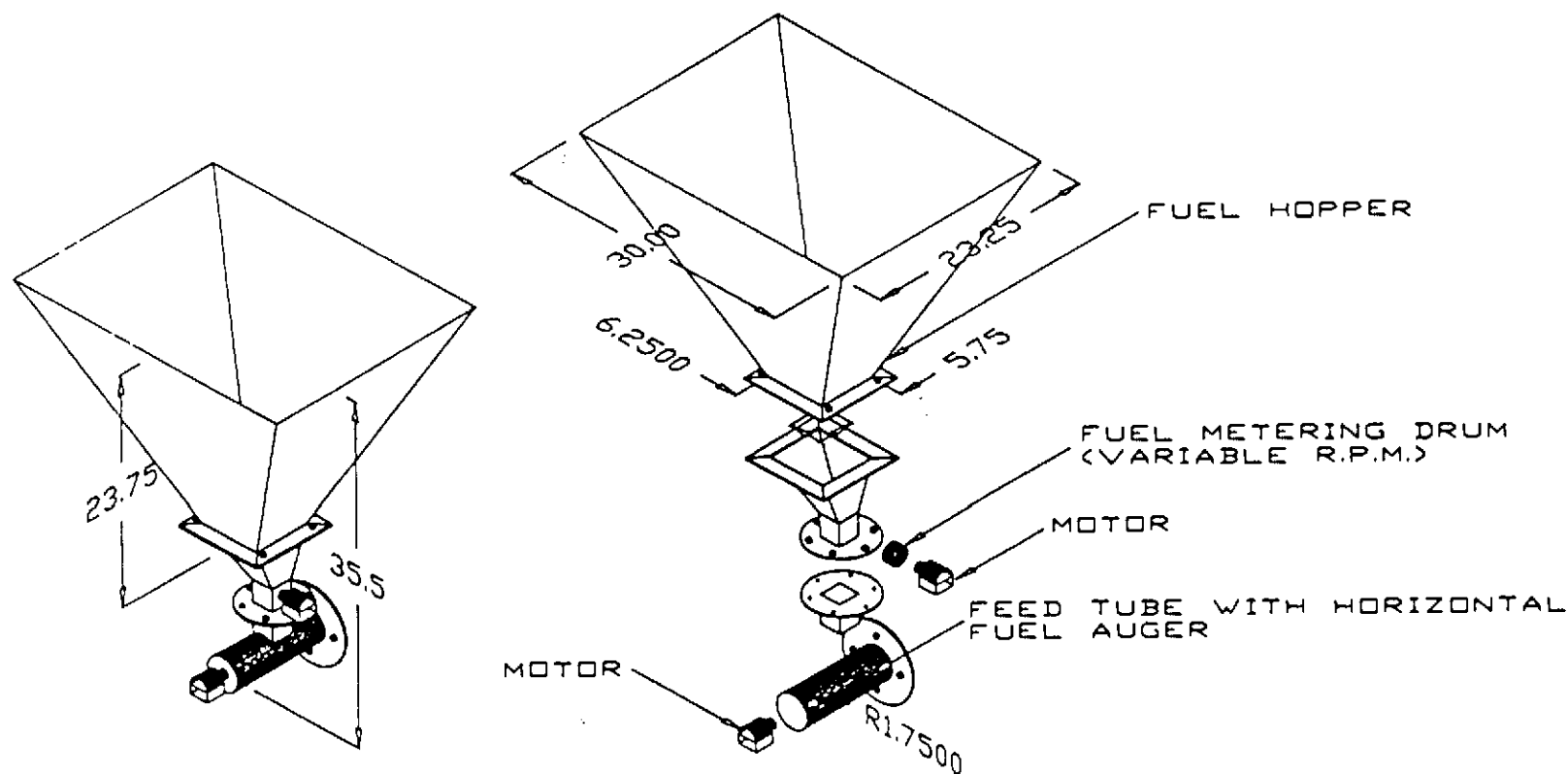
6.2500   5.75

23.75   35.5

R1.7500

Figure 21.   Fuel Hopper, Metering Drum, and Horizontal
Auger.   This System Feeds Pellet Fuel to the Biomass
Combustion Unit (BCU). Dimensions are in INCHES.