

**COAL/BIOMASS FUELS AND THE GAS TURBINE:  
UTILIZATION OF SOLID FUELS AND THEIR DERIVATIVES**

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**ABSTRACT**

This paper discusses key design and development issues in utilizing coal and other solid fuels in gas turbines. These fuels may be burned in raw form or processed to produce liquids or gases in more or less refined forms. The use of such fuels in gas turbines requires resolution of technology issues which are of little or no consequence for conventional natural gas and refined oil fuels. For coal, these issues are primarily related to the solid form in which coal is naturally found and its high ash and contaminant levels. Biomass presents another set of issues similar to those of coal. Among the key areas discussed are effects of ash and contaminant level on deposition, corrosion, and erosion of turbine hot parts, with particular emphasis on deposition effects.

The aim of this paper is to consider the key requirements of generic GT components, namely compressor, combustor, and turbine. This is the heart of the GT plant, developed at considerable cost, which the coal-use plant developer hopes to use with as little change as possible (Corman, 1995). Bringing key problem areas into sharper focus will help keep attention on areas where improvement and innovation have the largest payoff and where development effort must be directed. The concerns with coal are also relevant for other solid fuels such as biomass. Among the key areas discussed are: effects of ash and contaminant level on deposition, corrosion, and erosion of turbine hot parts; effects of ash and contaminant level on emissions; and combustor design.

**INTRODUCTION**

This paper discusses key design and development issues which must be addressed in order to utilize fuels derived from coal and other solid fuels in gas turbines (GTs). These fuels may be burned in raw form or processed with various degrees of sophistication to produce refined solids, liquids or gases.

The development of coal use in GTs requires resolution of technology issues which are of little or no consequence for conventional natural gas and refined oil fuels. These issues are primarily related to the solid form in which coal is naturally found and its high ash and contaminant levels. Unlike refined, conventional fuels, the structure and chemistry of coal, its ash, and its impurities are extremely variable.

**CHARACTERIZATION OF FUELS**

Coals from different sources vary greatly in both physical and chemical characteristics, depending on the biomass from which they have been derived, their ages, and the severity of physical conditions to which they have been subjected. For our purposes, coals can be regarded as mixtures of hydrocarbons, chemically bound impurities, and adventitious impurities. The hydrocarbons, which contain from one to seven percent hydrogen, constitute the fuel component. Oxygen, nitrogen, and sulfur are the most abundant chemically-combined impurities. Silicon, aluminum, iron, calcium, magnesium, sodium, potassium, and sulfur are adventitious contaminants. Adventitious sulfur occurs as sulfides of iron and other metals. Ash from combustion of coal consists essentially of the oxides of the metallic

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impurities.

The separation processes applied to coal-derived gas fall into three main categories as follows:

- Dry physical separation (cyclones, filters, etc.)
- Dry chemical separation (e.g., reaction of sulfur species with active sorbents)
- Wet separation (scrubbing with water or chemical solutions).

When coal cleaning is confined to physical separation of ash forming constituents, for example by washing or density separation, the products of combustion cannot be passed through a gas turbine without further treatment. Usually this means dust removal in high efficiency cyclones, or in ceramic filters. The efficacy of either method is directly related to the number of stages used, the acceptable pressure drop penalty, and the cost. Typically, practical cyclone systems have achieved dust burdens around 200 ppm(w) when applied to pressurized fluidized bed combustors. Ceramic candle filter systems have achieved dust levels below 10 ppm in prototype testing. The limiting factors are leakage around filter seals and damaged filters that occur in multi-filter arrays.

Cyclones and ceramic filters can also be used in gasification systems. In this application the product gas can be partially cooled before filtration, thus simplifying design and improving reliability of filter systems. Also the volume of gas to be treated is only one third to one tenth of the products of combustion, which permits the use of more dust separation stages without incurring excessive pressure loss penalties in the turbine hot gas path.

Dry chemical treatment is carried out by contacting a suitable reactant (such as iron or zinc based materials) with the product gas to remove sulfur compounds. The reagent can be regenerated to recover sulfur. The U.S. Department of Energy has expended considerable effort on the development of hot sulfur removal methods. (Bevan, 1995), (Ghazanfari, 1995), (Gangwal, 1995).

The use of dry separation methods is critical to the successful use of pressurized fluidized combustion and pressurized air blown gasification systems, for which the costs and thermal losses incurred in wet scrubbing are unacceptable. For the richer gases from oxygen blown gasifiers or pyrolyzers wet scrubbing becomes economically possible, and for the relatively simple tar free gases from oxygen blown

gasifiers the process is fairly simple. Very high levels of purity are possible, but again economic considerations come into play. Ash, sulfur compounds, and chlorine compounds, can all be removed. Particulate levels on the order of 1 ppm can be achieved in practical systems, with sulfur below 100 ppm.

An important consideration in the removal of ash from coal gasification processes is the behavior of volatile metallic compounds, in particular those related to the alkali metals, sodium and potassium. When the gases are cooled before filtration these compounds, which are in vapor form at gasification temperatures, condense progressively onto the surfaces of solid ash particles, and are removed with them at the filter. If filtration is carried out without such cooling the alkali vapors can pass through the filter whereas most of the solids are retained. As a result, the inorganic (ash) impurities entering the GT combustor will be alkali rich, and even in low concentrations they will be potentially corrosive to turbine components. Preferably, filtration should occur at temperatures low enough, below 600°C, depending on pressure, to avoid this problem. As well as the inorganic ash forming impurities coal includes a range of complex organic molecules, some of which incorporate oxygen and nitrogen atoms. These can cause complications in fuel handling, combustion and emissions. Sulfur, as well as contributing to emissions, has a propensity to form corrosive salts, especially with any alkali metals that may be present.

Table 1 presents approximate values of the fuel impurity levels that can be expected following the coal conversion and for product purification methods listed in the first two columns. It must be emphasized that in general, minimal data is available on the actual performances of full-scale or even pilot-scale gas cleanup systems, especially in terms of alkali metal levels and other details of gas contaminant compositions. It is clear, however, that with the lower heating value gases and dry gas cleanup systems the total impurity levels, in terms of mass per unit of energy input (mg/MJ) are liable to be much higher than those with the better quality scrubbed fuels. Note that all of the impurity levels listed in Table 1 are well above those found in natural gas supplies, in which solid contaminants are not usually present in detectable amounts, and sulfur levels are about 10 ppm - less than 1 mg/J.

TABLE ONE: Approximate Impurity Levels For Coal Derived Fuels  
(By Weight)

Conversion Method	Cleaning Method	Cleaning Temp. Deg. C	Non-alkali Solids (oxide)		Alkali (as oxides)		Sulfur (elemental)		Tars		Fixed N2	
			ppm	mg/Mj	ppm	mg/Mj	ppm	mg/Mj	ppm	mg/Mj	ppm	mg/Mj
raw coal	as mined		1x10 <sup>6</sup>	3800	2000	70	2x10 <sup>4</sup>	700	-	-	1x10 <sup>4</sup>	350
size reduced												
99% < 44	washed		7000	200	200	8	1x10 <sup>4</sup>	300	-	-	1x10 <sup>4</sup>	300
pyrolysis	hot filter	600	3-10	0.06-0.2	0.05-0.4	0.001-0.01	100	2	1x10 <sup>4</sup>	200	2x10 <sup>4</sup>	400
pyrolysis	wet scrub		1	0.02	1	0.02	100	2	1x10 <sup>4</sup>	0.2	100	2
liquefactn	crude		1000	25	50	1	2000	50	10	250	1x10 <sup>4</sup>	250
liquefactn	distilled		0	0	0	0	1000	25	0	0	2000	50
air blown	hot filter	600	3-10	0.9-3	0.05-0.4	0.01-0.1	1000	300	500	150	500	150
gas		950			2	0.8						
O2 blown	hot filter	600	3-10	0.9-3	0.05-0.6	0.004-0.05	100	300	0	0	500	40
gas		950			3	0.3						
O2 blown	wet scrub		0.1	0.01	0.01	0.001	100	9	0	0	100	9
gas												
combustn	hot cyclone	840C	200*	90	0.1-4*	0.05-2	150*	70	-	-	200*	100
(PFBC)	hot filter	750C	3-10*	1.2-4	0.1-4*	0.03-1	150*	70	-	-	200*	100
combustn	clean slurry		60*	20	8*	3	800*	300	-	-	200*	80
(cyclone)												

NOTE \* Indicates ppm in products of combustion

Because biomass is the precursor of coal it is not surprising that it has many of the characteristics of coal. The main differences lie in its lower carbon content, higher level of volatile constituents, lower level of contamination by adventitious minerals, and lower sulfur content. Table 2 shows how the ratio of volatile matter to fixed carbon changes in the progressive development of biomass from fresh material through young coals to highly carbonized coals.

Reactivity tends to increase with VM content, thus biomass fuels are relatively responsive to gasification, pyrolysis, and liquefaction treatment, and to biological treatments such as fermentation and microbial digestion. These can be attractive for small scale upgrading operations because severe thermal and pressure conditions are unnecessary. Furthermore, the bioprocessing routes do not result in carry-over of ash forming constituents or tars, which simplifies or eliminates purification steps. However, the low energy density of biomass tends to increase plant and fuel transportation costs. The heating value of wood is around 19KJ/g (green) or 33KJ/g (dry) compared with 50 KJ/g for coal, and most biomass fuels also have low density, about 1/3 that of coal,

Table 2: Ratio of Volatile Matter (VM) to Fixed Carbon (FC) in Solid Fuels

Fuel	VM/FC	
Biomass	Wood	3.8
	Bark	3.0
	Peat	2.0
Coal	Lignite	1.0
	Sub Bituminous	0.7
	High Volatile Bituminous	0.6
	Low Volatile Bituminous	0.2
Anthracite	0.1	

necessitating large equipment.

In summary, coal and biomass contain ash forming impurities which must be removed from the fuel or from the combustion products before they can be passed through a gas turbine. Inertial separation (e.g. in cyclones) and hot gas filtration are feasible at up to 900°C. Refined fuels prepared from coal or biomass by liquefaction or gasification can be purified to acceptable levels. Oxygen blown gasifiers

followed by wet gas cleaning can achieve ash levels around 0.1 ppm (0.01 mg/MJ) and sulfur content below 100 ppm (9mg/MJ). Pyrolysis, applicable especially to biomass, can produce gases that can be cleaned to similar levels. Some biomass fuels can also be gasified by biological processes without carryover of ash forming impurities.

#### NATURE AND DEPOSITON BEHAVIOR OF COAL AND BIOMASS IMPURITIES

There have been numerous attempts to relate the fusion behavior of coal ash to its chemical composition, but the complexity of ash chemistry precludes the possibility of finding a reasonably simple universal relationship (Bryers 1982). In any case, ash deposition behavior does not relate simply to bulk fusion characteristics, and deposit chemistry and characteristics may differ significantly from those of the parent ash. The bonding of ash particles to one another and to engine components depends essentially on their surface properties, which in turn are influenced strongly by the condensation of volatilized alkali compounds onto particle surfaces as gas temperatures drop. Further condensation and chemical modification occurs after deposition has occurred, and can lead to formation of corrodants such as complex salts. Most of our experience comes from coal fired boilers. In coal fired boilers, each of the various depositing species is active over a fairly well-defined temperature range, within which its corrosive effects can be characterized graphically by a bell-shaped curve relating corrosivity to temperature. This curve lies between the minimum temperature at which the depositing material will adhere (fusion temperature) and the maximum temperature at which it is physically or chemically stable. For species of major concern in boilers the relationships are fairly well-known. For example, (Borio, et.al.,1977) show a curve of stainless steel corrosion versus temperature rising from about 550°C to a peak at 650°C and falling off below 700°C at which the corrosive alkali/iron pyrosulfates responsible for corrosion become unstable. (Shigeto, et.al., 1986) show similar data for a range of corrosion resistant alloys attacked by a synthetic ash, and their results also illustrate the concentration of alkalis in the inner layers of deposits. Unfortunately, there is a lack of similar plant scale data that might apply at higher temperatures and with the mixture of possible depositing species that would apply in modern gas turbines where metal temperatures up to

1000°C may be encountered. While pyrosulfate corrosion, if it occurs, will likely be confined to the later turbine stages, the possibility exists of encountering partially fused particles, which may also be corrosive, in the range of metal temperatures between 700°C and 1000°C. Sodium and potassium form a number of compounds including oxides, carbonates, silicates, chlorides and sulfates with melting points in this range, and in combination with other substances they present a considerable potential for deposit formation and corrosion. In the presence of sulfur, the stable corrosive forms are alkali sulfates. (Imet, 1989).

In attempts to develop direct coal fired gas turbines the concern at first was erosion of blades by solid ash, with uncooled blades running at 750-850°C. Work on pressurized fluidized bed systems at these temperatures has demonstrated that even with dust burdens of 200 ppm entering the turbine serious erosion can be avoided if the ash particle size is below 5 microns (Boericke, 1982). Work on cyclone fired or other ash retentive slagging gas turbine combustors has illustrated the difficulty of achieving, at acceptable pressure drop, particulate ash burdens below 300 ppm when operating at gas temperatures above 1000°C except when using coals of very low ash content. With inertial separators such as cyclones and moderately clean coals, particulate burdens around 1000 ppm or more were experienced by Allison. (Wenglarz, 1992).

The ash residue from biomass combustion is very variable in composition, but in general is characterized by relatively high levels of alkali ( $K_2O$  and  $Na_2O$ ). Wood is often contaminated with soil during harvesting, resulting in total ash levels as high as 5 percent and elevated levels of  $SiO_2$ ,  $Al_2O_3$ , and  $CaO$ , all of which are also inherently present in the wood. Typically, wood ash represents about 1 or 2 percent of the dry mass and most analyses report that the ash contains about 30-50 per cent  $CaO$ , 10-20 percent  $SiO_2$ , 5 - 15 percent  $MgO$ , 4-6 percent  $K_2O$  and 2-3 percent  $Na_2O$ . However, analysis by low temperature plasma ashing suggests that potassium levels may be much higher, (Zicherman, 1972). Potassium exists in the wood as highly volatile compounds such as halide salts which may be lost in conventional analysis. The sulfur content of biomass is also variable but always relatively low, on the order of 0.1 percent or less. This sulfur is nonetheless significant, because it results in formation of complex sulfate eutectics with potassium, sodium, calcium, and magnesium. These can have melting

points as low as 650°C and are potentially corrosive. The alkalis can form glasses with silica and other metals and these will be molten over a range of temperatures above about 750°C. Thus, the potential for fouling and/or corrosion of gas turbines by biomass fuels is considerable, and the problem is aggravated by the volatility of the alkalis. Pyrolytic oil from wood bark has ash and sulfur contents about half those of wood (Power from Wood, 1980) and would need refining to avoid fouling problems if used as a fuel, while gas made from biomass would appear to require scrubbing or low temperature filtration to remove alkali vapors and aerosols.

Experience with direct biomass firing in gas turbines supports the foregoing analysis, although the low temperature deposit problem has been exacerbated by using sulfur - containing oil as auxiliary or starting fuel (Hamrick, 1991). All reported experience has applied to low temperature turbine operation (TiT < 750°C). At these temperatures, biomass firing without auxiliary fuel did not form serious deposits. Additions of CaO were effective in absorbing SO<sub>2</sub>, and rendering deposits more friable.

## CRITICAL TURBINE CONCERNS

### COMBUSTOR DESIGN

#### Types of combustors

The type of combustor selected will be dictated by engine performance objectives.

a) What are the emission objectives?

NO<sub>x</sub>, CO, particulate, UHC (unburned hydrocarbon) (sulfur is a pass-through insofar as the combustor is concerned)

b) What is the TiT level?

c) What is fuel form?

Indirect air, medium Btu gas, low Btu gas, liquid, FBN containing fuel, Solids

d) Will exhaust cleanup be used?

e) Stability at turndown, especially with lean mixtures

There are three basic types of combustors to consider:

- Conventional (diffusion flame) combustor  
Requires water or steam injection for NO<sub>x</sub> control
- DLN (Dry Low NO<sub>x</sub>; a lean premixed flame) combustor.

When burning natural gas presently producing NO<sub>x</sub> levels less than 25 PPM.

- Rich-lean combustor

Controls NO<sub>x</sub> when fuel has Fuel Bound Nitrogen

(FBN) but is more complex than other combustors and is not yet commercial.

Indirect burning, such as in a PFBC, transmits hot air to the turbine and therefore requires no gas turbine combustor function.

#### Matching Combustor Types to Fuel Types

- Indirect Fired

Requires no gas turbine combustor, but will require compressor-air-out and turbine-flow-in sections at the turbine plant mid-section. Since TiT is heat exchanger-limited, hot gas transport from the heat exchanger should pose no technical problems.

- Medium Btu Gas (7.5 - 15 MJ/m<sup>3</sup>, 200 to 400 Btu per SCF)

It should be possible to modify DLN combustors to burn this gas. Modification of fuel gas port sizes and development testing will be required.

Conventional combustors are also applicable here. NO<sub>x</sub> control by lean burn design and water or steam injection is required.

- Low Btu Gas (3 - 5.6 MJ/m<sup>3</sup>, 90 to 150 Btu per SCF)

For this fuel conventional combustors are suitable, (Pillsbury, et al., 1976). Because of the large inert content of this fuel, the NO<sub>x</sub> generated will be low. If required, further NO<sub>x</sub> reduction by water or steam injection is possible. Combustor may require enlarged diameter primary zone to attain complete burning of the fuel which has a high inert content. One may not be able to generate 1300°C gas with lower heating values.

- Liquid Fuels (from coal or biomass)

Conventional combustors with water or steam injection for NO<sub>x</sub> control are applicable here. DLN combustors which operate on liquid fuel would also be applicable, when development for liquid fuel operation is completed.

- Fuel Bound Nitrogen, (FBN)-containing fuels

A rich-lean combustor will be required where the fuel contains a significant amount of FBN. (Toof, 1985). The Allison company operated a rich-lean combustor briefly in an engine test (Wenglarz, 1986).

- Solid fuel

Here the coal/biomass combustible arrives at the combustor containing hydrocarbon solids. The prime



choices here are conventional or rich/lean. The requirement to burn solids means that flame residence times 10X greater than for gas or distillate oil are required and combustors will have to be commensurately larger than conventional combustors. If the combustors are external to the turbine casing, which is likely because of the combustor size required, combustion and ash removal processes may be combined (Scalzo, et.al., 1991).

If combustors are external, the ability to operate at high TiT (say above 1200°C) will be limited by the hot gas transport ducting distance to turbine inlet.

The combustor choice will be affected if exhaust cleanup devices are to be used, with NOx control burden shifted to exhaust devices such as Selective Catalytic Reduction (SCR).

#### Development Testing

The combustor types (conventional combustors less than others) will require extensive testing either in a test laboratory or in prototype engine operation itself. The matchup of combustor and fuel types is summarized as follows:

	Conventional	DLN	R-L
Med BTU Gas	X	X	
Low BTU Gas	X		
Liquid Fuels	X	X	
Fuel w/FBN			X
Solid Fuels	X		X

#### DEPOSITION ON HOT PARTS

Figure 1, a figure from the U.S. Department of Energy's (High Temperature Turbine Technology Program, 1977) and (DeCorso, 1980) shows the experience with turbine deposition as related to average particle size and turbine inlet temperature, TiT. This plot was prepared considering a variety of actual engine operating cases. The plot may also be considered as one of particle concentration vs. TiT. The plot implies the existence of a threshold of particle concentration (and size) at any particular TiT below which deposition will not occur. The deposition threshold in turn may also be linked to the corrosion threshold.

The concept of a deposition threshold suggests that deposition and corrosion can be avoided by design even with high dust burdens. Experience indicates that this is true. Starting in the late 1940's and into the early 1970's all GT manufacturers had active lab test programs to determine the threshold for

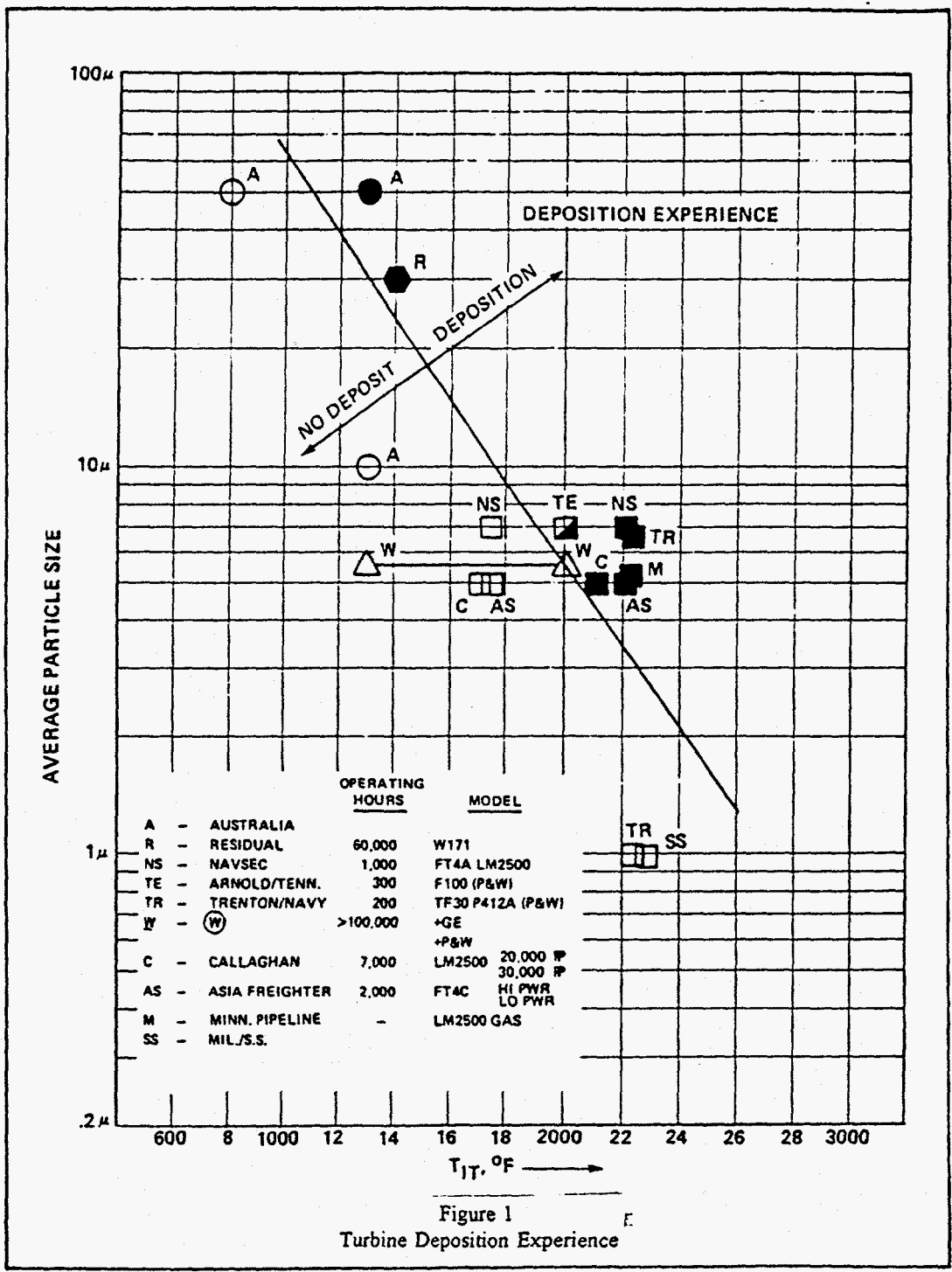
the allowable contaminant level for various fuels. This work was driven by the active consideration of a variety of liquid fuels at that time including residual fuel and crude oil, and involved laboratory investigations with benchmark forays into field tests. From this work the current ASTM GT fuel specification D-2880 evolved. (ASTM Standards, 1989), (Hussey, 1968). These contaminant limits typically are in the range of a few ppm allowable in the fuel. The work also suggested that the metal temperature governs the corrosion process and the gas stream temperature, per se, is largely irrelevant.

With the advent of natural gas as the primary fuel for GTs, lab tests of the deposition and corrosion limits were stopped, and the fuel specifications (and limits on contaminants in the hot gas stream) were frozen. Now we are entering a product cycle where TiT's have increased from the 1975 levels (1000°C) to 1425+°C, but our knowledge of the critical threshold of deposition (and corrosion) is frozen at the 1975 level. Natural experiments have occurred which are relevant to our discussion, namely - volcanic explosions at: Mt. St. Helen's, Oregon; Redoubt, Alaska, and Galunggung, Java, with aircraft flying through volcanic dust clouds. Engine failures due to deposition of the dust occurred. (New York Times, 1995). The newer, hotter engines were more susceptible to deposition problems. (Science, 1981). Concern with deposition in airplane engines flying through volcanic ash or the debris of war led to the work of (Kim, 1992) and (Dunn, 1994), wherein engines were operated in a laboratory with simulated volcanic ash injection. These tests can be seen to represent test points on the concentration/particle size vs. TiT plot such as that of Figure 1 and are of fundamental interest to our discussion, if the dust loading used were known. It was reported that selected engine parameters responded very quickly to the presence of a dust cloud when the engine was operating at a TiT in excess of 1090°C.

#### EFFECT ON TiT

(Borio, 1986) showed that in steam boiler conditions the gas temperature affects the rate and character of deposition onto heat transfer surfaces (Fig. 2).

Deposits change from powdery at lower temps to sintered/friable in a transition range and molten at higher temperatures. These deposits are more massive than those in gas turbines and are formed under very different conditions; however, despite earlier indications to the contrary (noted above), tests



have also shown extreme effects of gas temperature on deposits formed from coal-water fuels on turbine alloy specimens at turbine gas velocities and surface

temperatures (Wenglarz, 1986). Deposits formed at a 1093°C gas temperature (Figure 3) are two orders of magnitude greater than deposits formed at a 982°C gas temperature (See Figure 4).



Figure 2 - Deposition on Boiler Tubes

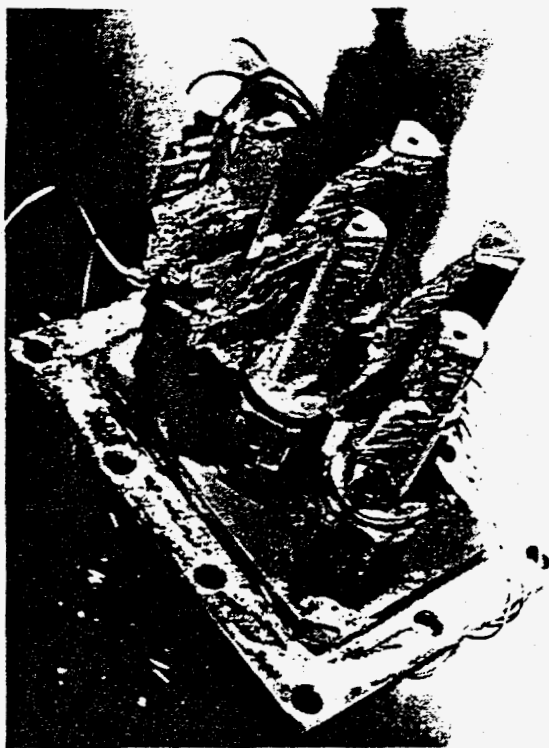
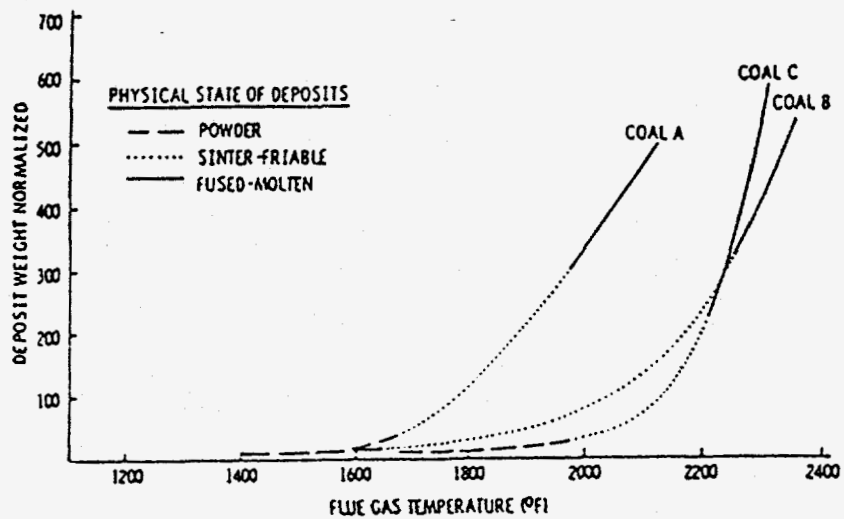


Figure 3 - Deposits Formed From CWF at Gas Temperature of 1093C

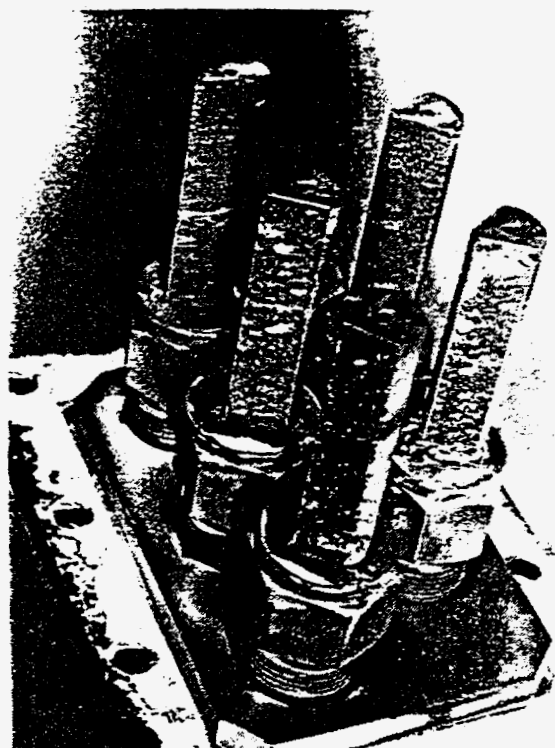


Figure 4 - Deposits Formed From CWF at Gas Temperatures of 982C



Figure 5 - Deposits Formed From a Coal-Derived Liquid Fuel at 1260C

Similar gas temperature effects on deposition have also been observed in tests of residual oils and coal-derived liquid fuels. A washed and treated residual oil produced about 30 times higher deposition rates at a gas temperature of 1260°C compared to a gas temperature of 1038°C (Whitlow, 1981). At the 1260°C gas temperature, deposits as thick as 2.8 cm were formed in 300 hours, even though the gas stream particle concentration was only on the order of 10 ppmw. Heavy deposits were also formed (Figure 5) in about 100 hours at a gas temperature of 1260°C from a coal-derived liquid fuel which produced about 2 to 3 ppmw particulate loading in the gas stream (Mulik, 1985).

These and other tests with ash-bearing fuels have shown the following typical deposition characteristics:

- low levels of deposition which are not strongly affected by gas temperature at lower temperatures
- a transition gas temperature above which deposition rates drastically increase with gas temperature, along with deposit tenacity
- above the transition temperature, high deposition rates can occur even for very low gas stream particle concentrations on the order of a few ppmw and lower.

## TURBINE MASS FLOW RATES

Combustion turbines are very high mass flow engines. Mass flows can range up to 680 kg/sec (e.g., for the GE Frame 7G/H turbines). At particle loadings of 3 to 5 ppmw, such as pass through hot gas filters in alternate fuel plants (Wenglarz, 1995), an advanced 15,000 hp industrial turbine could ingest 2400 to 3900 kg of particulates in an 8000 hour operating year. A GE Frame 7G/H would ingest 65 to 108 tons. Excessive turbine deposition occurs if only a very small fraction of the particulate is delivered to the expander airfoils and sticks on those surfaces. For example, less than 0.32 kg of deposited ash blocked the first stator row flow area to the verge of compressor surge during turbine tests using a coal-water fuel (Wenglarz, 1992). That turbine was about the same scale as the 15,000 hp advanced industrial engine mentioned above which would ingest 2400kg of particulate in 8000 hr at 3ppmw entering the expander. The potential for serious deposition is obvious, but the probability of it occurring is not well defined.

## TURBINE INLET TEMPERATURES

Industrial and utility turbines are being developed with rotor inlet temperatures up to 1427°C. This is well above the gas temperatures that produced extreme deposition, even for gas stream particle concentrations down to 2 to 3 ppmw in the tests of alternate fuels described earlier. The magnified rates of deposition occurred in these tests because the gas stream temperature was above the melting point of a significant fraction of the fuel ash particulate. The transition temperature range where deposition greatly increases corresponds to the melting of various ash constituents. An assessment of phase chemistry diagrams (Tabakoff, 1988) indicates that constituents of ash, dust, and dirt will be molten at the inlet temperatures of 1427°C, the TiT of the next generation industrial and utility turbines.

Figure 1 indicates that excessive deposition has occurred in commercial and experimental turbines with relatively low inlet temperatures compared to current designs. More recently, turbines located at a gypsum wallboard plant ingesting about 0.3 ppmw particulate in the air (which then passed through a multistage inlet air cleanup system including barrier filters) experienced severe deposition in 10,000 hours and less (John, 1995).

## CORROSION

A major cause of accelerated corrosion in the hot section of GTs is the ingestion of species that can react in the combustion zone to form condensable alkali sulfates. Certain molten salts can effectively dissolve the protective oxide scale formed on GT hot parts, greatly accelerating the depletion of the reservoir of protective scale-forming elements. These species may enter in the fuel and in the air. The impurities involved in condensed salt attack (commonly known as Type I hot corrosion) are sulfates and chlorides of the alkali metals (Na and K), and of the alkaline earths (Ca and Mg). This form of attack occurs in the metal temperature range 955°C to 790°C, and the dew point of the condensable salts is a function of both concentration of salt in the gas, and the total pressure.

When the duty cycle of current GTs results in operation where the surface temperatures of the critical first stage vanes and blades is above about 955°C, the major mode of high-temperature corrosion of these components is oxidation. With increasing total pressure, however, the dew point of the condensable salts is increased so that Type I hot corrosion will likely be possible at higher temperatures in future turbines. SO<sub>3</sub> in the combustion gas (which may form from the catalytic oxidation of SO<sub>2</sub> on component surfaces) can lead to a further form of accelerated corrosion - Type II Hot Corrosion in which low-melting (590°C) mixtures of sodium and cobalt sulfates can form. This form of hot corrosion occurs in the metal temperature range of approximately 750 to 600°C, and so is a factor for the later-stage vanes and blades.

## EROSION

The main approach to mitigating erosion in gas turbines is through the setting of limits on allowable particulate ingestion. Specifications are set by gas turbine manufacturers for the maximum acceptable amount and size of solid particles entering the turbine. For example one set of recommendations specified that particle size be less than six microns. (High Temperature Turbine Technology Program, 1977). It is expected that fuel-related erosion problems will be a concern in combustion and expansion turbines only under upset conditions in the gas clean-up systems.

## STATE-OF-THE-ART TURBINE MATERIALS AND DEVELOPMENTS

Turbine materials development is currently focused on achieving higher inlet temperatures with conventional turbine fuels using single-crystal and directionally - solidified superalloys, refractory metals, intermetallics, and ceramics (Bannister, et al., 1994). The high-temperature materials are coupled with improved blade cooling techniques and thermal barrier coatings (for example, Yttria-stabilized zirconia, alumina, TiN). Little development is in progress to improve the resistance of turbine materials to erosion. Some evaluations to understand the potential of limiting erosion and deposition damage by improved aerofoil design have been conducted. (Wenglarz, 1995).

## EMISSIONS SPECIFICATIONS

Emission regulations vary significantly with plant location throughout the world. For developing technologies, such as solid-fuel gas turbines, the properties of the solid fuel and the demonstrated emissions experience of the fuel processing technology will weigh heavily on the emissions requirements adopted by local agencies. In the U.S., the 1990 Clean Air Act Amendments require the consideration of standards for hazardous air pollutants (HAPs), including several metals, volatile organic compounds, HCl, dioxins and furans, and specifically include the consideration of particulate matter less than 10 microns in diameter (PM-10). Preliminary indications are that the HAPs regulations will not have a great impact on solid fueled utility power plants, except possibly for HCl emissions, mercury and PM-10.

It is expected that the emissions regulations for solid fueled gas turbine plants will be similar to those for conventional power plants burning the same solid fuel. The current New Source Performance Standard (NSPS) for coal-fired electric utility plants is 0.03 lb/MBtu particulate emission, equivalent to about 20-30 ppmw ash loading in the stack gas. The NSPS would allow particulate emissions from a coal-fueled turbine greater than those generally specified by the turbine manufacturer based on erosion and deposition considerations. PM-10 legislation may make the emissions requirements for solid fuels more stringent than required for turbine protection.

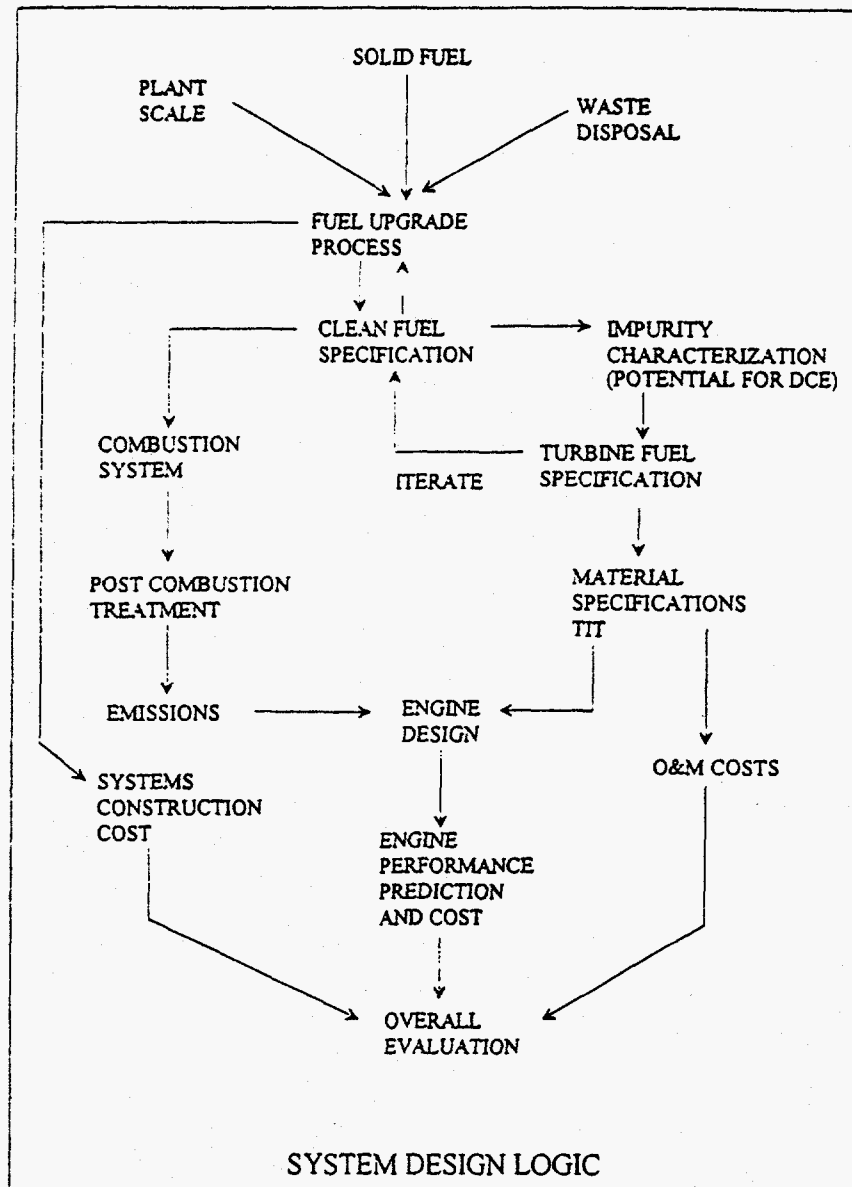


Figure 6  
System Design Logic

**DESIGN/ DECISION LOGIC**

It is possible to construct design/decision charts covering the key design issues discussed in this paper. Such charts show schematically a sequence in which overall plant component decisions have to be made and where additional design information is required. A simplified form of such a chart is shown in Figure 6. The chart illustrates that potential deposition/corrosion/erosion (DCE) effects must be evaluated early in the process.

**CONCLUSIONS AND RECOMMENDATIONS**

A number of advanced power systems are being developed to operate on natural gas with ostensible future use on coal and biomass fuels. However, except for coal gasification with cold gas scrubbing and first generation PFBC, a relatively small amount of work has been directed to verifying the prospects for the successful marriage of the GT with many of the upgrading processes being considered for coal and biomass fuels in the future. Knowing deposition

thresholds for coal - and biomass - derived fuels is critical to reliable turbine operation.

From the standpoint of advanced gas turbines and future markets there appears to be little justification for pursuing fuel upgrading processes that do not produce very clean products. PFBC, using raw coal and relatively inefficient turbines may still be competitive because of low fuel costs.

Three basic types of combustors to consider in covering the various possible coal and biomass fuels: Conventional (diffusion flame burning); DLN (lean premixed flame combustor); and rich-lean combustor. These combustors (conventional combustors less than others) will require extensive testing either in a test laboratory or in prototype engine operation itself.

Development testing, when required, should start with relatively inexpensive tests using specimens rather than expensive turbine engine tests. Until the capability is developed to protect specimens from excessive deposition, corrosion, and erosion, (DCE) there will not be the capability to protect turbine airfoils at the same gas and surface temperatures. Basic tests/analyses are recommended to develop the fundamental knowledge necessary for control of DCE at these high temperatures. The DOE Wilsonville test plant (Geiling, 1993) offers a facility not only to test hot gas cleanup devices and turbines, but also to conduct relatively inexpensive DCE tests downstream of cleanup devices. The test facility at the General Electric R & D Center has capability to produce a variety of derivative fuels for turbine component testing (Corman, 1993).

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