GAS TURBINE PERFORMANCE AND MAINTENANCE

Rainer Kurz
Manager, Systems Analysis
Solar Turbines Incorporated
San Diego, CA, USA

Klaus Brun
Director, Machinery Program
Southwest Research Institute®
San Antonio, TX, USA

Cyrus Meher-Homji
Bechtel Fellow
Bechtel Corporation
Houston, TX, USA

Jeff Moore
Manager, Rotating Machinery Dynamics
Southwest Research Institute®
San Antonio, TX, USA

Dr. Rainer Kurz is the Manager, Systems Analysis, at Solar Turbines Incorporated in San Diego, California. His organization is responsible for analyzing compression require-ments, predicting compressor and gas turbine performance, for conducting application studies, and for field performance testing. Dr. Kurz attended the Universitaet der Bundeswehr in Hamburg, Germany, where he received the degree of a Dr.-Ing. in 1991. He has authored numerous publications about turbomachinery related topics, is an ASME fellow, and a member of the Turbomachinery Symposium Advisory Committee.

Dr. Klaus Brun is the Director of the Machinery Program at Southwest Research Institute. His experience includes positions in engineering, project management, and management at Solar Turbines, General Electric, and Alstom. He holds four patents, authored over 100 papers, and published a textbook on gas turbines. Dr. Brun won an R&D 100 award in 2007 for his Semi-Active Valve invention and ASME Oil Gas Committee Best Paper awards in 1998, 2000, 2005, 2009, 2010, and 2012. He was chosen to the "40 under 40" by the San Antonio Business Journal. He is the chair of the ASME-IGTI Board of Directors and the past Chairman of the ASME Oil & Gas Applications Committee. He is also a member of the API 616 Task Forces, the Fan Conference Advisory Committee, and the Latin American Turbomachinery Conference Advisory Committee. Dr. Brun is an editor of Global Gas Turbine News, Executive Correspondent of Turbomachinery International Magazine, and an
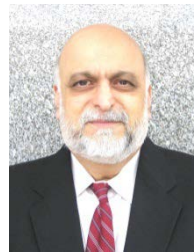
Associate Editor of the ASME Journal of Gas Turbines for Power.

Cyrus Meher-Homji is an Engineering Fellow and Senior Principal Engineer at Bechtel Corporation assigned to the LNG Technology Center of Excellence as a turbomachinery advisor to ongoing LNG projects on the aeromechanical design, selection, and testing of large compressors and gas turbines. His 32 years of industrial experience cover gas turbine and compressor application, design, and troubleshooting. Cyrus is a registered Professional Engineer in the State of Texas, a Fellow of ASME, and he is active in several committees of ASME's International Gas Turbine Institute. He has a Master's Degree in Engineering from Texas A&M University and an MBA from the University of Houston. He is a member of the Texas A&M University Turbomachinery Symposium Advisory Committee.

Dr. Jeffrey Moore is the Manager of the Rotating Machinery Dynamics Section at Southwest Research Institute in San Antonio, TX. He holds a B.S., M.S., and Ph.D. in Mechanical Engineering from Texas A&M University. His professional experience over the last 20 years includes engineering and management responsibilities related to centrifugal compressors and gas turbines at Solar Turbines Inc. in San Diego, CA, Dresser-Rand in Olean, NY, and Southwest Research Institute in San Antonio, TX. His interests include advanced compression methods, rotordynamics, seals and bearings, computational fluid dynamics, finite element analysis, machine design, controls, and aerodynamics. He has authored

over 30 technical papers related to turbomachinery and has three patents pending. Dr. Moore has held the position of Oil and Gas Committee Chair for IGTI Turbo Expo and is the Associate Editor for the Journal of Tribology. He is also a member of the Turbomachinery Symposium Advisory Committee, the IFToMM International Rotordynamics Conference Committee, and the API 616 and 684 Task Forces.

ABSTRACT

Proper maintenance and operating practices can significantly affect the level of performance degradation and thus, time between repairs or overhauls of a gas turbine. Understanding of performance characteristics of gas turbines helps proper applications, as well as driven and process equipment sizing. Proactive condition monitoring will allow the gas turbine operator to make intelligent service decisions based on the actual condition of the gas turbine rather than on fixed and calendar based maintenance intervals. Maintaining inlet air, fuel, and lube oil quality will further reduce gas turbine degradation and deterioration. This tutorial provides a discussion on performance characteristics and how performance degradation can be minimized. Recommendations are provided on how the operator can limit degradation and deterioration of the gas turbines through proper maintenance practices. The effects of water-washing and best washing practices are discussed. Emphasis is on the monitoring of gas turbine performance parameters to establish condition based maintenance practices.

INTRODUCTION

How Does a Gas Turbine Work?

Explanations of the working principles of a gas turbine have to start with the thermodynamic principles of the Brayton cycle, which essentially defines the requirements for the gas turbine components. Since the major components of a gas turbine perform based on aerodynamic principles, we will explain these, too.
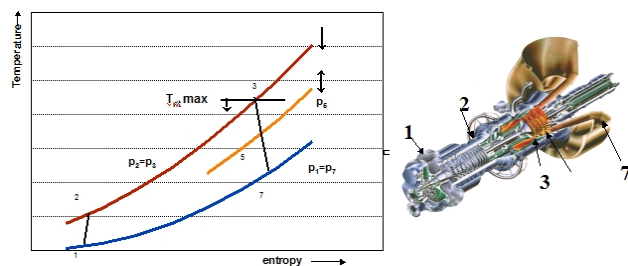

Figure 1: Brayton Cycle

The Brayton or gas turbine cycle (Figure 1) involves compression of air (or another working gas), the subsequent heating of this gas (either by injecting and burning a fuel or by indirectly heating the gas) without a change in pressure, followed by the expansion of the hot, pressurized gas. The compression process consumes power, while the expansion process extracts power from the gas. Some of the power from the expansion process can be used to drive the compression process. If the compression and expansion process are performed efficiently enough, the process will produce useable power output. This principle is used for any gas turbine, from early concepts by F. J. Stolze (in 1899), C.G. Curtiss (in 1895), S. Moss (in 1900), Lemale and Armengaud (in 1901), to today's jet engines and industrial gas turbines (Meher-Homji, 2000). The process is thus substantially different from a steam turbine (Rankine) cycle that does not require the compression process, but derives the pressure increase from external heating. The process is similar to processes used in Diesel or Otto reciprocating engines that also involve compression, combustion, and expansion. However, in a reciprocating engine, compression, combustion, and expansion occur at the same place (the cylinder), but sequentially, in a gas turbine, they occur in dedicated components, but all at the same time.

The major components of a gas turbine include the compressor, the combustor, and the turbine.

The compressor (usually an axial flow compressor, but some smaller gas turbines also use centrifugal compressors) compresses the air to several times atmospheric pressure. In the combustor, fuel is injected into the pressurized air from the compressor and burned, thus increasing the temperature. In the turbine section, energy is extracted from the hot pressurized gas, thus reducing pressure and temperature. A significant part of the turbine's energy (from 50 – 60 percent) is used to power the compressor, and the remaining power can be used to drive generators or mechanical equipment (gas compressors and pumps). Industrial gas turbines are built with a number of different arrangements for the major components:

- Single-shaft gas turbines have all compressor and turbine stages running on the same shaft
- Two-shaft gas turbines consist of two sections: the gas producer (or gas generator) with the gas turbine compressor, the combustor, and the high pressure portion of the turbine on one shaft and a power turbine on a second shaft (Figure 2). In this configuration, the high pressure or gas producer turbine only drives the compressor, while the low pressure or power turbine, working on a separate

shaft at speeds independent of the gas producer, can drive mechanical equipment.

- Multiple spool engines: Industrial gas turbines derived from aircraft engines sometimes have two compressor sections (the HP and the LP compressor), each driven by a separate turbine section (the LP compressor is driven by an LP turbine by a shaft that rotates concentric within the shaft that is used for the HP turbine to drive the HP compressor), and running at different speeds. The energy left in the gas after this process is used to drive a power turbine (on a third, separate shaft), or the LP shaft is used as output shaft.
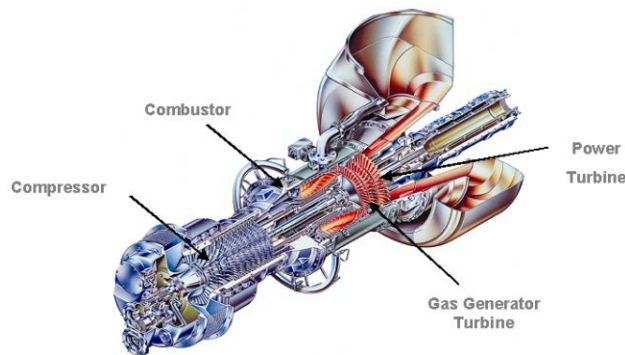

Figure 2: Typical Industrial Gas Turbine

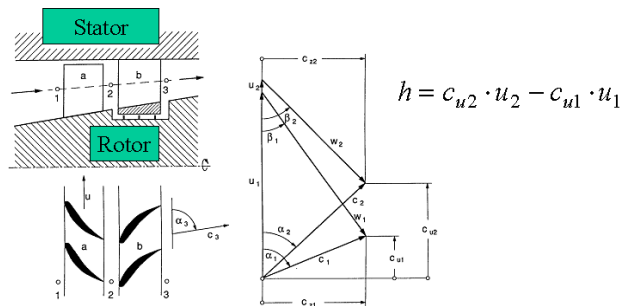$$h = c_{u2} \cdot u_2 - c_{u1} \cdot u_1$$

Figure 3: Velocities in a Typical Compressor Stage. Mechanical Work h Transferred to the Air is Determined by the Change in Circumferential Momentum of the Air.

The **energy conversion** from mechanical work into the gas (in the compressor) and from energy in the gas back to mechanical energy (in the turbine) is performed by the means of aerodynamics, by appropriately manipulating gas flows. Leonard Euler (in 1754) equated the torque produced by a turbine wheel to the change of circumferential momentum of a working fluid passing through the wheel. Somewhat earlier (in 1738), Daniel Bernoulli stated the principle that (in inviscid, subsonic flow) an increase in flow velocity is always accompanied by a reduction in static pressure and vice versa, as long as no external energy

is introduced. While Euler's equation applies Newton's principles of action and reaction, Bernoulli's law is an application of the conservation of energy. These two principles explain the energy transfer in a turbomachinery stage (Figure 3).

The compressed air from the compressor enters the gas turbine **combustor**. Here, the fuel (natural gas, natural gas mixtures, hydrogen mixtures, diesel, kerosene and many others) is injected into the pressurized air and burns in a continuous flame. The flame temperature is usually so high that any direct contact between the combustor material and the flame has to be avoided, and the combustor has to be cooled, using air from the engine compressor. Additional air from the engine compressor is mixed into the combustion products for further cooling.

Another important topic is the combustion process and emissions control:

Unlike in reciprocating engines, the gas turbine combustion is continuous. This has the advantage that the combustion process can be made very efficient, with very low levels of products of incomplete combustion like carbon monoxide (CO) or unburned hydrocarbons (UHC). The other major emissions component, oxides of nitrogen (NO_x), is not related to combustion efficiency, but strictly to the temperature levels in the flame (and the amount of nitrogen in the fuel). The solution to NO_x emissions, therefore, lies in the lowering the flame temperature. Initially, this was accomplished by injecting massive amounts of steam or water in the flame zone, thus 'cooling' the flame. This approach has significant drawbacks, not the least the requirement to provide large amounts (fuel to water ratios are approximately around 1) of extremely clean water. Since the 1990's, combustion technology has focused on systems often referred to as dry low NO_x combustion, or lean-premix combustion (Figure 4). The idea behind these systems is to make sure that the mixture in the flame zone has a surplus of air, rather than allowing the flame to burn under stoichiometric conditions. This lean mixture, assuming the mixing has been done thoroughly, will burn at a lower flame temperature and thus produce less NO_x. One of the key requirements is the thorough mixing of fuel and air before the mixture enters the flame zone. Incomplete mixing will create zones where the mixture is stoichiometric (or at least less lean than intended), thus locally creating more NO_x. The flame temperature has to be carefully managed in a temperature window that minimizes both NO_x and CO. Lean-premix combustion systems allow to keep the NO_x, as well as CO and UHC emissions within prescribed limits for a wide range of loads, usually between full load and about 40 or 50% load. In order

to accomplish this, the air flow into the combustion zone has to be manipulated over the load range.

Gas Turbine Performance Characteristics

The gas turbine power output is a function of the speed, the firing temperature, as well as the position of certain secondary control elements, like adjustable compressor vanes, bleed valves, and in rare cases, adjustable power turbine vanes. The output is primarily controlled by the amount of fuel injected into the combustor. Most single-shaft gas turbines run at constant speed when they drive generators. In this case, the control system modifies fuel flow (and secondary controls) to keep the speed constant, independent of generator load. Higher load will, in general, lead to higher firing temperatures. Two-shaft machines are preferably used to drive mechanical equipment, because being able to vary the power turbine speed allows for a very elegant way to adjust the driven equipment to process conditions. Again, the power output is controlled by fuel flow (and secondary controls), and higher load will lead to higher gas producer speeds and higher firing temperatures.
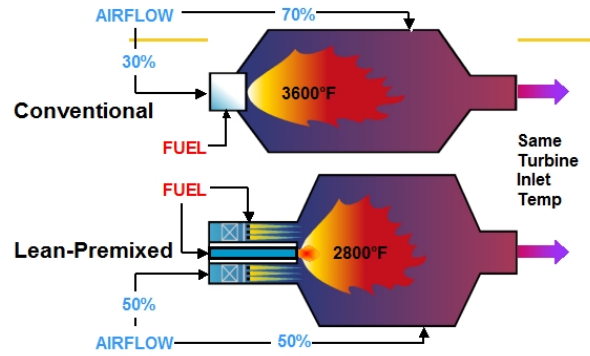

Figure 4: Conventional and Lean-Premix Combustion Systems

Figure 5 shows the influence of ambient pressure and ambient temperature on gas turbine power and heat rate. The influence of ambient temperature on gas turbine performance is very distinct. Any industrial gas turbine in production will produce more power when the inlet temperature is lower, and less power when the ambient temperature gets higher. The rate of change cannot be generalized, and is different for different gas turbine models. Full-load gas turbine power output is typically limited by the constraints of maximum firing temperature and maximum gas producer speed (or, in twin spool engines, by one of the gas producer speeds). Gas turbine efficiency is less impacted by the ambient temperature than the power.
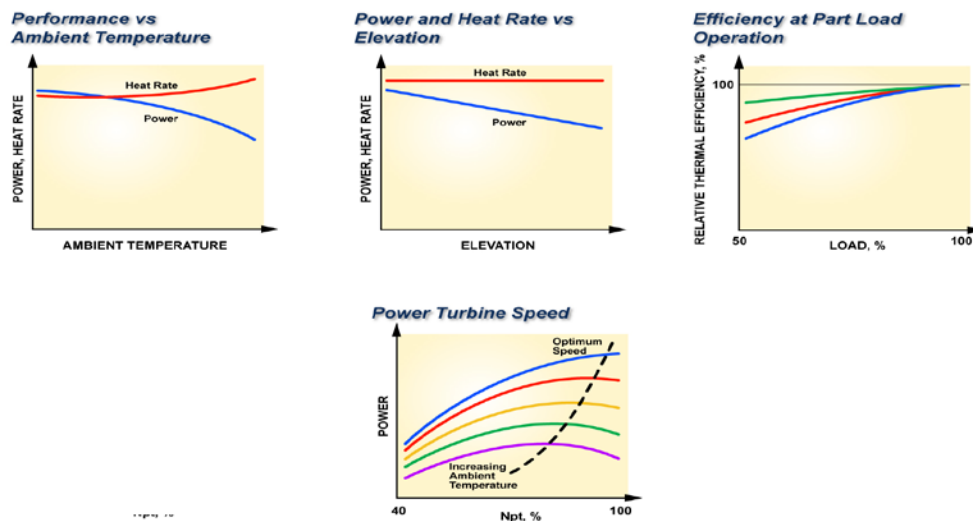

Figure 5: Performance Characteristics

The humidity does impact power output, but to a small degree, (generally, not more than 1 to 3%, even on hot days). The impact of humidity tends to increase at higher ambient conditions.

Lower ambient pressure (for example, due to higher site elevation) will lead to lower power output, but has practically no impact on efficiency. It must be noted that the pressure drop due to the inlet and exhaust systems impact power and efficiency negatively with the inlet pressure drop having a more severe impact.

Gas turbines operated in part load will generally loose some efficiency. Again, the reduction in efficiency with part load is very model specific. Most gas turbines show a very small drop in efficiency for at least the first 10% of drop in load. In two-shaft engines, the power turbine speed impacts available power and efficiency. For any load and ambient temperature, there is an optimum power turbine speed. Usually, lowering the load (or increasing the ambient temperature) will lower the optimum power turbine speed. Small deviations from the optimum (by say +/- 10%) have very little impact on power and efficiency.

Key cycle parameters for any gas turbine are its specific work and thermal efficiency which are related to the cycle pressure ratio and turbine inlet temperature. The general qualitative relationships between PR and TIT are indicated in Figure 6 (Meher-Homji et al., 2009).

The salient relationships of this figure may be conveniently summarized as follows:

1. For a given TIT, gas turbine specific work increases with pressure ratio, reaching a maximum and then decreasing with further pressure ratio increase.
2. The specific work increases with increasing turbine inlet temperature.
3. The maximum specific work as the TIT is increased occurs at increasing pressure ratios.
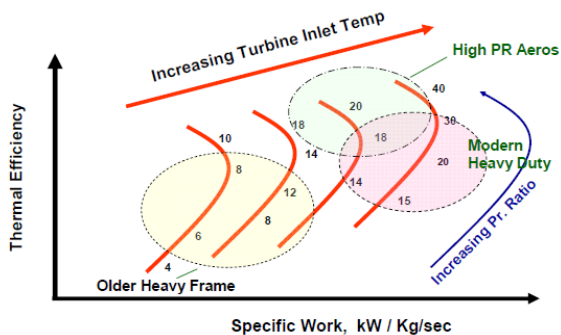

Figure 6: Key Cycle Parameters

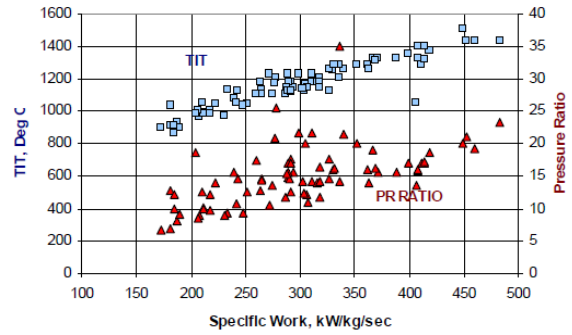Pressure ratios and TIT parameters of a wide range of industrial gas turbines are shown in Figure 7.

Figure 7: Pressure Ratios and Firing Temperature Parameters of a Wide Range of Industrial Gas Turbines

AIR AND AIR INLET SYSTEMS

Gas turbines ingest a large amount of ambient air during operation. Because of this, the quality of the air entering the turbine is a significant factor in the performance and life of the gas turbine. A filtration system is used to control the quality of the air by removing harmful contaminants that are present. The system should be selected based on the operational philosophy and goals for the turbine, the contaminants present in the ambient air, and expected changes in the contaminants in the future due to temporary emission sources or seasonal changes.

Filters used in Gas turbine applications include

- Barrier Filters
- Self Cleaning Filters
- Vanes/Separators
- Screens

Gas turbine applications typically require filtration systems that use combinations of different filter types. Often, the face velocity is used to distinguish high velocity and medium/low velocity systems (Wilcox, et al., 2011).

Filter systems have to deal with a number of contaminants, such as large and small particles, as well as liquids. Particles can be removed from the air stream by various types of filtration materials. Water (and salts dissolved in the water) can be removed either by inertial separation (i. e., vane separators), or by filtration materials that repel water.

For off-shore applications, where salt water ingestion is a major concern, two filtration concepts have emerged: High Velocity Systems and Medium/Low Velocity System. These systems are also often used in coastal areas. For land-based applications, most applications use either barrier filters or self cleaning filter systems. Self-cleaning filter systems are essentially barrier filters that allow the

occasional use of pressurized air to pulse clean the filter material.

Applications also may have to deal with issues like heavy rain, cold and freezing temperatures, snow or sand storms, swarming insects, very high or very low relative humidity and combinations thereof.

Filtration Mechanisms

Filters in the filtration system use many different mechanisms to remove particles from the air. The filter media, fiber size, packing density of the media, particle size, and electrostatic charge influence how the filter removes particles. Each filter typically has various different mechanisms working together to remove the particles. Four filtration mechanisms are shown in Figure 8.

The first filtration mechanism is inertial impaction. This type of filtration is applicable to particles larger than 1 micron in diameter. The inertia of the large heavy particles in the flow stream causes the particles to continue on a straight path as the flow stream moves around a filter fiber. The particulate then impacts and is attached to the filter media and held in place as shown in the top picture of Figure 8. This type of filtration mechanism is effective in high velocity filtration systems.

The next filtration mechanism, diffusion, is effective for very small particles typically less than 0. 5 micron in size. Effectiveness increases with lower flow velocities (see Figure 8 h, second picture). Small particles interact with nearby particles and gas molecules. Especially in turbulent flow, the path of small particles fluctuates randomly about the main stream flow. As these particles diffuse in the flow stream, they collide with the fiber and are captured. The smaller a particle and the lower the flow rate through the filter media, the higher probability that the particle will be captured.
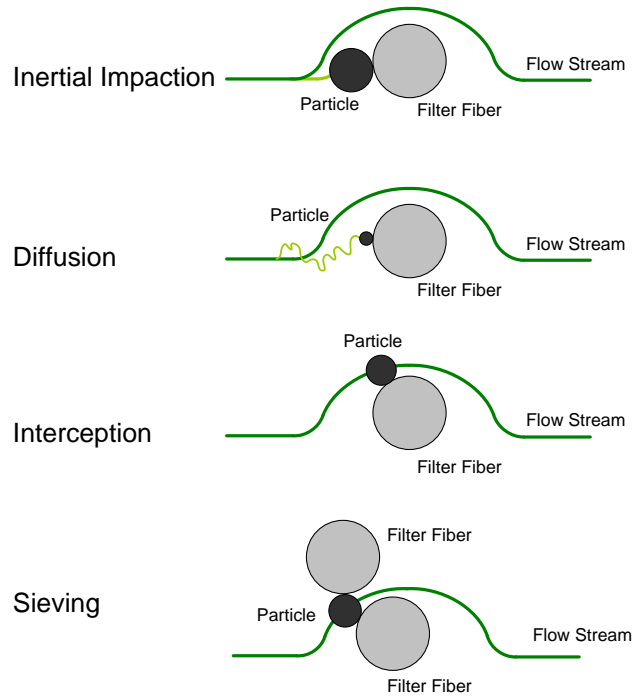
Figure 8: Common Filtration Mechanisms

The next two filtration mechanisms are the most well known; interception and sieving. Interception occurs with medium sized particles that are not large enough to leave the flow path due to inertia or not small enough to diffuse. The particles will follow the flow stream where they will touch a fiber in the filter media and be trapped and held. Sieving is the situation where the space between the filter fibers is smaller than the particle itself, which causes the particle to be captured and contained.

Figure 9: Combination of Filtration Mechanisms to Obtain Filter Efficiency at Various Particle Sizes

A mechanism not shown in Figure 8 is electrostatic charge. This type of filtration is effective for particles in the 0. 01 to 2 micron size range (Figure 9). 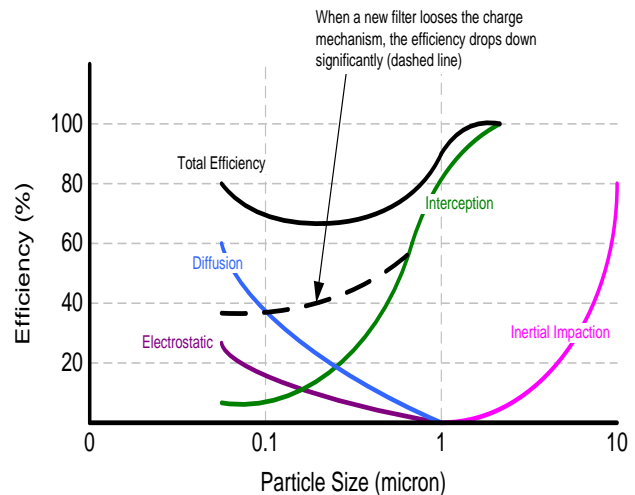The filter works through the attraction of particles to a charged filter. In gas turbine applications, this charge is applied to the filter before installation as a result of the manufacturing process. Filters always lose their electrostatic charge over time because the particles captured on their surface occupy charged sites, therefore neutralizing their electrostatic charge. As the charge is lost, the filter efficiency for small particles will decrease. On the other hand, as the filter is loaded, the filtration efficiency increases, thus counteracting the effect of lost charge to some extent. This will offset some of the loss of filtration efficiency due to the lost charge. Figure 9 shows a comparison of a filter's total efficiency based on the various filtration mechanisms that are applied. The figure shows the difference between the filter's efficiency curve before and after the charge is lost. The performance of the filter should be based on the discharged condition [Felix, P. C., 1977, Felix, P. C., 1979].
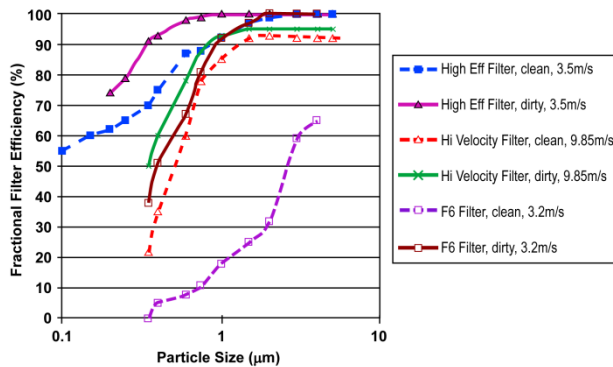

Figure 10: Comparison of Fractional Efficiency for Filter Elements from Different Suppliers and Different Face Velocities in New and Dirty Conditions (Brekke and Bakken, 2010)

Different filter systems show different effectiveness for different dry particle sizes (Figure 10). The paragraph above outlines methods to remove solid particles from the airstream. However, as outlined earlier, ingestion of liquids is also an issue. Liquid water can contain dissolved salts and can penetrate conventional filter materials regardless of their capability filter our solid particles. At high humidity, water can actually form in the filter system. Water can dissolve dirt already captured in the filtration material and seep through the filter. Therefore, water removal is a crucial feature for air filtration systems especially in off-shore, marine and coastal environments. There are two fundamental methods to remove water: either with vanes upstream and downstream of the filter system or with special

filter material that cannot be penetrated by water, typically in the last, high-efficiency, filter stage. Water removal with vanes favors high air flow velocities, and thus, high velocity filtration systems. Water removal with special high efficiency filter material favors low/medium velocity systems. Both methods, if applied properly, are capable of preventing liquid water to enter the gas turbine. However, as can be determined from Figure 10, high-velocity systems tend to have a lower filtration efficiency for solid particles than can be achieved with low/medium velocity systems.

FUEL AND FUEL TREATMENT

Industrial gas turbines allow operation with a wide variety of gaseous and liquid fuels, while maintaining very low emissions. Recent discussions include the use of LNG as fuel gas and the operation of gas turbines with fuel gas from a number of different sources. Lean premix combustion systems, widely used for emissions control, require particular considerations regarding the fuel quality and fuel composition. To determine the suitability for operation with a gas fuel system, various physical parameters of the proposed fuel need to be considered: heating value, dew point, Wobbe index and others. Attention is given to the impact of fuel constituents on combustion characteristics and the problem of determining the dew point of the potential fuel gas at various pressure levels. The impact of fuel properties on emissions, and the proper operation of the combustion system are discussed. Suggestions about how to approach fuel suitability questions during the project development and construction phase, as well as in operation are made (Kurz et al., 2006).

Gas Fuels

The quality and composition of fuel burned in a gas turbine impacts the life of the turbine, particularly its combustion system and turbine section. The fuel specified for a given application is usually based on availability and price. Natural gas is a typical fuel of choice for gas turbines due to its low (but increasing) cost, widespread availability, and low resulting emissions. However, the composition of fuel gas can widely vary, from gas with significant amounts of heavier hydrocarbons[1] (butane and heavier), to pipeline quality gas consisting mostly of methane, to fuel gas with significant amounts of noncombustible gases (such as nitrogen or carbon dioxide).

The fuel composition impacts the entire gas turbine system. For example, fuels with a large amount of noncombustible components can move the

---

1 Hydrocarbons in fuel gas are usually alkanes, with the summary chemical formula C_nH_{2n+2}

operating point of the gas turbine compressor closer to its stall limit. They also have an impact on the power and efficiency of the gas turbine. Fuel choices impact the pollutant emissions levels. Durability issues, especially of the hot section, due to corrosive compounds or the formation of liquids in gaseous fuels, have to be addressed. Combustor operability (and durability) issues, especially for lean premix combustion systems depend on the choice of fuel. Certain fuel types pose safety challenges for the gas turbine package due to their flammability, containment (hydrogen is an example), and/or toxicity (carbon monoxide, hydrogen sulfide) issues.

Current dry low emissions technology primarily focuses on burning natural gas, a fuel that is mainly composed of methane. However, interest in utilizing other energy resources, in reducing pollutant emissions, as well as concern about energy security, have motivated interest in utilizing associated gas and raw natural gas, coal-derived syngas or fuels from other sources, such as biomass, landfill gas, or process gas. For many applications, dry, low-emissions systems also have been designed to burn liquid fuels like Diesel.

Gas fuels for gas turbines are combustible gases, or mixtures of combustible and inert gases with a variety of compositions covering a wide range of heating values and densities. The combustible components can consist of methane and other low molecular weight hydrocarbons, hydrogen and carbon monoxide. The major inert components are nitrogen, carbon dioxide and water vapor. It is generally accepted that this type of fuel has to be completely gaseous at the entry to the fuel gas system, and at all points downstream to the fuel nozzle.

The amount of energy that will be released during the combustion process for a specific gaseous fuel composition is determined by the heating value. For simple cycle gas turbines, the lower heating value is generally used since the latent energy of the steam is not recovered. Gaseous fuels can be categorized by the lower heating value, but another parameter is used more commonly in the gas turbine industry. That parameter is the *Wobbe index*. From the lower heating value (LHV) in Btu/scf [kJ/Nm^3] and the specific gravity (SG), the Wobbe index (WI) of the gas can be calculated:

$$WI = \frac{LHV}{\sqrt{SG}}$$

Because the fuel supply temperature T_f has an impact on the actual volumetric fuel flow, a temperature corrected Wobbe index is often used,

where the reference temperature T_{ref} is usually 520°R or 288°K:

$$WI = \frac{LHV}{\sqrt{SG}} \cdot \sqrt{\frac{T_{ref}}{T_f}}$$

If two different fuel gas compositions have the same Wobbe index, the pressure drop in a given fuel system will be the same for both gases and in general, direct substitution is possible and no change to the fuel system is required. The Wobbe index is, thus, an indication of energy flow in the system at the same gas pressure and pressure drop.

The Wobbe index is used as a parameter to indicate the ability of the overall fuel handling and injection system to accommodate the fuel composition. If the Wobbe index varies too far from the design value, changes to the fuel system need to be made. A high Wobbe index often indicates the presence of heavier hydrocarbons in the fuel, while a low Wobbe index is often caused by the presence of significant amounts of noncombustible fuel components or by the presence of significant amounts of (highly combustible) hydrogen or carbon monoxide.

Because a lower Wobbe index means, that the fuel mass flow, relative to the engine air mass flow increases, the power output of an engine increases slightly (Figure 11) when the Wobbe Index is lowered.

However, the Wobbe index does not capture the effects of other fuel properties, such as dew point, flame speed and combustion chemistry. Therefore, the entire fuel composition must also be considered and, if more reactive species such as hydrogen, alkenes and carbon monoxide are present in significant quantities, additional changes to the fuel system may be required. A good design criterion is that gases having a Wobbe index within ±10% can be substituted without making adjustments to the fuel control system or injector flow area. If the fuel injector flow area has to be changed, the gas Wobbe index should be inversely proportional to the effective controlling area of the injector.
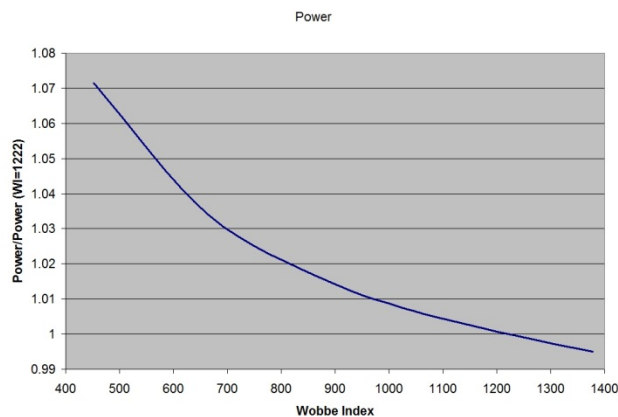
Figure 11: Impact of Wobbe Index on Gas Turbine Power Output (Typical)

For a typical landfill gas, the Wobbe index is one-third the value of standard pipeline quality natural gas. The controlling orifices on the injectors must be enlarged to three times their previous area. This allows the fuel flow rate of the landfill gas to have an equivalent pressure drop across the injector at full-load condition. This will provide stable, high efficiency combustion, with the desired turbine inlet temperature distribution, for long combustor and blade life.

As the fuel heating value decreases below standard levels, the torch igniter and the combustion system may require standard natural gas or liquid fuel for startup or shutdown, as well as possible restrictions on turbine transient load operation.

Gaseous fuels can be classified based on changes required to the injector, fuel or control systems as specified in Table 1. The table includes special start-up requirements and limitations in loading based on the class of gas fuel. Both Lean Premix and conventional combustion gas turbines can be designed to use the standard fuel with Wobbe index range of 1220 ±10%. This range would be typical of pipeline quality natural gas. High heating value fuels are accommodated with minor changes to the control systems and can be used in conventional combustion and, to a lesser degree, in gas turbines with lean premix combustors. Very high heating value fuels usually require that the fuel temperature be monitored closely to prevent two-phase (gas and liquid) flow. For medium heating value fuels, conventional combustion may require a change in injector flow area. Low heating value fuels require even more extensive changes to the injector and fuel system. The last category of very low heating values has limited

application for conventional combustion only. DLN combustion systems in industrial gas turbines are usually designed for standard natural gas. The use with other gases (either high BTU or medium BTU) usually requires careful evaluation and testing.

Gaseous fuels can be divided into four distinct categories as indicated in Figure 12. These categories are broadly based on the fuel source. A description of each of these fuels is included in Table 2.

Fuel Gases in Oil and Gas Upstream and Midstream Applications

Gas fuels produced from oil and natural gas reserves include: raw natural gas, associated gas, pipeline quality natural gas, liquefied natural gas (LNG), natural gas liquids (NGL) and liquefied petroleum gas (LPG).

Table 1: Classification of Gaseous Fuels

Fuel Energy Density	Wobbe Index BTU/scf (MJ/Nm^3)
Very High (NGL & LPG)	>1600 (>59. 6)
High	1342 – 1600 (50. 0 – 59. 6)
Standard (Pipeline)	1098 – 1342 (40. 9 – 50. 0)
Medium	700 – 1098 (26. 1 – 40. 9)
Low	350 – 700 (13. 0 – 26. 1)
Very Low	<350 (<13. 0)

Natural gas is extracted from the ground either with crude oil or from natural gas reservoirs. It is primarily a mixture of naturally occurring paraffin hydrocarbons including methane (CH_4), ethane (C_2H_6), propane (C_3H_8,) butane (C_4H_{10}), pentane (C_5H_{12}), hexane (C_6H_{14}), and higher molecular weight compounds. Hydrocarbons heavier than propane form isomers, such as iso-butane (iC_4H_{10}) and iso-pentane (iC_5H_{12}) that have different properties than their 'normal' counterparts. Additionally, other gases such as carbon dioxide, hydrogen sulfide, mercaptanes, water vapor, and nitrogen can be present.
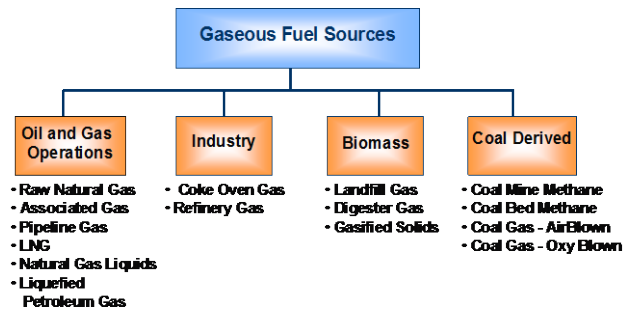
Figure 12: Gas Turbine Gaseous Fuel Categories

Associated Gas is extracted with crude oil and found either dissolved in the oil or as a cap gas above the oil in the reservoir. Historically, associated gas has been treated as a by-product of oil extraction and has either been flared or re-injected to extract more oil. Burning associated gas in the gas turbines used to extract the crude oil has been recognized in the past two decades as a more economical and environmentally sensitive approach. The majority of associated gas is produced offshore, complicating further efforts to recover and utilize these gases. The composition of associated gas depends on the type of reservoir from which it originated.

Raw Natural Gas or *wellhead gas* is extracted from gas wells. The gas reserves are generally classified as either dry or wet. Dry reserves do not contain appreciable condensable heavier hydrocarbons (pentane+), while wet reserves do. Natural gas containing hydrogen sulfide (H_2S) is referred to as sour gas. Excessive H_2S creates extensive corrosion problems on fuel-wetted parts; thus, stainless steel and/or coatings are often prescribed for equipment handling sour gas.

Pipeline Quality Natural Gas that is transported and distributed for industrial and residential use is a subset of raw natural gas. Pipeline gas has been processed to remove the heavier hydrocarbons and adjust the heating value of the fuel within prescribed limits. Methane is the lightest combustible component of natural gas and generally referred to interchangeably with pipeline-quality gas (>90%) because it is the major constituent. Mercaptans are typically added to pipeline gas to give a distinctive odor that facilitates gas leakage detection.

Liquified Natural Gas (LNG) is pipeline quality natural gas extracted remotely, chilled to a liquid (-260°F/-162°C), transported via tanker, heated, revaporized, processed as required and injected into an existing natural gas transmission and distribution network. LNG has a similar composition to pipeline natural gas.

Natural Gas Liquid (NGL) is a general classification for those paraffin hydrocarbons heavier than methane, which can be transported and distributed in liquid form. At atmospheric pressure, NGL is in the gaseous state. As a gas, NGL is separated from methane by liquefying it through the process of pressure, absorption, or a combination of both. Because of the relatively high dew point of this gas compared to natural gas, NGL is usually handled as a liquid fuel for most industrial gas turbine applications. A determination must be made for each source of NGL based on the fuel analysis as to whether the fuel should be handled in the gaseous or liquid phase.

Liquified Petroleum Gas (LPG) is a sub-classification of NGL referring specifically to propane and butane mixtures offered commercially. LPG is always transported in liquid form and as with NGL. LPG is usually handled as a liquid fuel in gas turbine applications.

Fuel Gases Produced in Industrial Applications

Several industrial and chemical processes generate significant quantities of gas by-products and waste streams with acceptable fuel composition and adequate calorific value for use in gas turbines without extensive equipment modifications. Primary industries producing such fuels include steel mills and chemical and refining plants.

Refinery Gas is a by-product of gasoline production. This gas contains high hydrogen (H_2) content, along with several other reactive species including ethylene and propylene, mixed with methane, ethane and propane. Refinery gas is corrosive and hydrogen has a great tendency to leak and is explosive, therefore, safety is the main concern. With the proper safety considerations incorporated into design modifications and minor fuel control adjustments, refinery waste gas has been successfully used to fuel industrial gas turbines. Hydrogen has a relatively low molecular weight and high flame speed compared to natural gas.

Coke Oven Gas is generated during the production of coal and petroleum coke for iron and steel production. It contains methane, hydrogen and some carbon monoxide and has a lower heating value than pipeline gas. Coke oven gas composition is quite variable and requires significant treatment to remove contaminants for use in a gas turbine combustion that produces gases with high carbon monoxide and hydrogen content.

Anaerobic Digestion Gas is the gas recovered from the decomposition of organic matter by bacteria

in the absence of oxygen. Anaerobic digestion occurs in:

- Liquid sewage
- Residues from fruit and vegetable canneries
- Animal and crop wastes
- Solid wastes disposed in sanitary landfills
- Marine plants, including macro-algae, water hyacinth and sea kelp

This process produces gas consisting of methane, nitrogen, carbon dioxide and air with a low heating value. Large variations in gas composition are common from different landfill and digester sites.

Fuel Gases Derived from Coal

Coal-derived gases include coal gas produced through several different gasification processes and gases that are collected during coal mining.

Coal Gas produced by gasification contains hydrogen, methane, and carbon monoxide as their combustible components, with large proportions of carbon dioxide and nitrogen as inerts. Depending on the type of gasification process, air-blown processes generate an LHV of from 3. 0 to 7. 9 MJ/Nm^3 (75 to 200 Btu/scf), while oxygen-blown processes yield medium BTU gases with a LHV of from 7. 9 to 21. 2 MJ/ Nm^3 (200 to 570 Btu/scf).

Coal Mine Gas is generally extracted in two forms: diluted with air as *Coal Mine Methane (CMM)* or as a high quality natural gas as *Coal Bed Methane (CBM)*. In a gaseous coal seam, methane concentration can be up to 94-98% with 1-5% carbon dioxide. For safety reasons, this gas has to be drained from underground coal seams, before mining, in the form of CBM. To prevent explosions in coal mines, extensive ventilation is required to extract gaseous methane trapped between coal seams and the surrounding rock. In practice, the gas/air mixture from the coal mine is further diluted with air during extraction and the resultant CMM gas contains 30 to 70% methane by volume. This gas/air mixture can be compressed and directly used as a fuel in a gas turbine. Since the methane fuel and its air oxidant are premixed in the fuel gas, potential explosion hazards need to be addressed. The methane content in the gas/air mixture should always be kept with a sufficient margin above the upper flammability limit, at the highest anticipated pressure and temperature.

Fuel Gases from Biomass

Biomass can be converted into potential gas fuels for industrial gas turbines through thermal gasification and anaerobic digestion.

Thermal Gasification is a process of heating wood and other biological substances without combustion that produces gases with high carbon monoxide and hydrogen content.

Contaminants

In many systems, the gas composition and quality may be subject to variations (Newbound et al., 2003). Typically, the major contaminants within these fuels are:

- Solids
- Water
- Heavy gases present as liquids
- Oils typical of compressor oils
- Hydrogen sulfide (H_2S)
- Hydrogen (H_2)
- Carbon monoxide (CO)
- Carbon dioxide (CO_2)
- Siloxanes

Other factors that will affect turbine or combustion system life and performance include lower heating value (LHV), specific gravity (SG), fuel temperature, and ambient temperature.

Some of these constituents and contaminants may co-exist and be interrelated. For instance, water, heavy gases present as liquids, and leakage of machinery lubricating oils, may be a problem for turbine operators at the end of a distribution or branch line, or at a low point in a fuel supply line.

Water in the gas may combine with other small molecules to produce a hydrate – a solid with an ice-like appearance. Hydrate production is influenced, in turn, by gas composition, gas temperature, gas pressure and pressure drops in the gas fuel system. Liquid water in the presence of H_2S or CO_2 will form acids that can attack fuel supply lines and components. Free water can also cause turbine flameouts or operating instability if ingested in the combustor or fuel control components.

Heavy hydrocarbon gases present as liquids provide many times the heating value per unit volume than they would as a gas. Since turbine fuel systems meter the fuel based on the fuel being a gas, this creates a safety problem, especially during the engine start-up sequence when the supply line to the turbine still may be cold. Hydrocarbon liquids can cause:

- Turbine overfueling, which can cause an explosion or severe turbine damage.
- Fuel control stability problems, because the system gain will vary as liquid slugs or droplets move through the control system.
- Combustor hot streaks and subsequent engine

hot section damage.

- Overfueling the bottom section of the combustor when liquids gravitate towards the bottom of the manifold
- Internal injector blockage over time, when trapped liquids pyrolyze in the hot gas passages.

Liquid carryover is a known cause for rapid degradation of the hot gas path components in a turbine (Anderson, 1980; Meher-Homji, et al., 1998; Newbound et al., 2003 and 2004).

The condition of the combustor components also has a strong influence and fuel nozzles that have accumulated pipeline contaminants that block internal passageways will probably be more likely to miss desired performance or emission targets. Thus, it follows that more maintenance attention may be necessary to assure that combustion components are in premium condition. This may require that fuel nozzles be inspected and cleaned at more regular intervals or that improved fuel filtration components be installed.

With a known gas composition, it is possible to predict dew point temperatures for water and hydrocarbons. However, the prediction methods for dew points may not always be accurate. In fact, it is known that different equations of state will yield different calculated dew points under otherwise identical conditions. Furthermore, the temperature in an unheated fuel line will drop because the pressure drop due to valves and orifices in the fuel line causes a temperature drop in the gas. This effect is known as the Joule-Thompson effect. Most fuel gases (except hydrogen) will exhibit a reduction in temperature during an adiabatic throttling. Hydrogen, on the other hand, actually shows an increased temperature when the pressure drops, which creates a potential explosion hazard.

Important Fuel Properties

Dew point of a gas is a function of gas composition, pressure and temperature. It describes the boundary between the single phase gas and the two phase (gas and liquid) state of a fluid (Elliott et al, 2002). Usually, the water dew point of a fuel gas is reported separately from the hydrocarbon dew point. One of the issues is that heavy hydrocarbons, even if they are only present in traces, have a large impact on the dew point. In many instances, a gas analysis lumps all the heavier hydrocarbons into one number (e. g., C_{6+}). Since the dew point depends on the distribution of the heavy hydrocarbons, estimates can be made based on characterization methods (Campbell, 2000). However, these estimates are often not very accurate,

and direct dew point measurements may be the preferred method.

In particular, there is no reproducible relationship between heating value and dew point. Because most gases will see a reduction in temperature during isenthalpic expansion (this is the Joule-Thompson Effect), it is possible that even a dry gas can develop liquids if it is subject to the pressure drop in a typical fuel supply system. It is, therefore, necessary to provide fuel gas sufficiently superheated. Values of 28°C/50°F of superheat at turbine skid edge are frequently used as a requirement, but the appropriate amount (which can be higher or lower) of superheat can be determined by a detailed dew point analysis. The amount of superheat needs to include allowances for uncertainty in the fuel gas composition at present and in the future, as well as the potential for heat loss of the fuel system.

Blowout refers to a situation where the flame becomes detached from the location where it is anchored and is physically "blown out" of the combustor. Blowout is often referred to as the "static stability" limit of the combustor. Blowout occurs when the time required for chemical reaction becomes longer than the combustion zone residence time. It can be an issue because the chemical kinetic rates and flame propagation speeds vary widely with fuel composition. For example, many candidate fuels have similar heating values but also have chemical kinetic times that vary by an order of magnitude (Lieuwen et al., 2006).

The opposite problem is *flashback*, where the flame physically propagates upstream of the region where it is supposed to anchor and into premixing passages that are not designed for high temperatures. Similar to blowout, flashback is an issue because of the widely varying flame speeds of candidate fuels. Again, fuels with similar heating values but with flame speeds that vary by factors of five or more are common (Lieuwen et al., 2006). Flashback occurs when the turbulent flame speed exceeds the flow velocity along some streamline, allowing the flame to propagate upstream into the premixing section. Flashback often occurs in the flow boundary layer, since this is the point of lowest flow velocity. As such, the effect of fuel composition variations upon flashback depend upon the corresponding change in *turbulent flame speed*. Flame speed is a propagation of the flame front moving in the combustion zone. Changes in the fuel composition, fuel to air ratio and inlet temperature affect the flame speed (Glassman, 1996).

The *laminar flame speed*, also called flame velocity, or burning velocity, is defined as the velocity

at which unburned gases move through the combustion wave in the direction normal to the wave surface (Glassman, 1996). A key point here is that the flame speed does not vary linearly between the respective pure values of the mixture constituents. For example, the addition of H_2 to CH_4 does not have a significant impact upon the flame speed until H_2 is the dominant constituent of the mixture. The impact of adding diluents, like CO_2, is, that the flame speed is still lower than the non-diluted mixtures, even if the temperature is maintained by increasing the equivalence ratio (Lieuwen et al, 2006).

However, most issues are related to the *turbulent flame speed*, which depends, besides the laminar flame speed, also on the turbulence levels of the gases in question. In particular, data show that, as the turbulence intensity increases, the turbulent flame speed initially increases, then asymptotes to a constant value, and then, at very high turbulence intensities, begins to decrease. The most obvious effect of fuel properties on the turbulent flame speed is through the laminar flame speed. For example, for a given turbulence intensity and a given burner, fuels with higher laminar flame speeds should have higher turbulent flame speeds. However, turbulence intensity and laminar flame speed alone do not capture many important characteristics of the turbulent flame speed. Two different fuel mixtures having the same laminar flame speed, turbulence intensity and burner can have *appreciably* different turbulent flame speeds depending on the diffusion characteristics of the species involved (Lieuwen et al., 2006).

Flame propagation velocity is also strongly influenced by the fuel/air mixture ratio; the leaner the mixture the lower the velocity. If the flow velocity exceeds the flame propagation velocity, then flameout could occur. If the flame propagation velocity exceeds the flow velocity, then flashback within the premixing injectors could occur that can cause damage by overheating the injector tips and walls. To maintain flame stability at a point, the velocity of the fuel-air mixture must be within the flame-propagation speed to prevent flashback (Lefebvre, 1998).

Flame flashback from the combustion chamber into the premixing zone is one of the inherent reliability problems of lean premixed combustion. The flame speed is one of the most important parameters governing flashback. High flame speeds occur, for example, in associated gases containing high percentages of propane or butane (Figure 13).
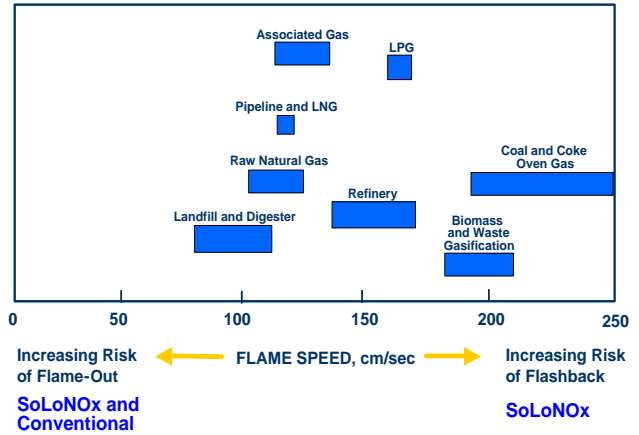

Figure 13: Fuel Type Effects on Flame Speed

Autoignition is a process where a combustible mixture spontaneously reacts and releases heat in absence of any concentrated source of ignition such as a spark or a flame (Lefebvre, 1998). Rather than the flame propagating upstream into the premixing section, autoignition involves spontaneous ignition of the mixture in the premixing section. Similar to flashback, it results in chemical reactions and hot gases in premixing sections, but its physical origins are quite different from those of flashback. In lean premix combustors, or in general, in any combustor where fuel and air are premixed prior to combustion, this spontaneous ignition inside the injector barrel has to be avoided, because it can damage combustor components, and yields high pollutant emissions. The *autoignition delay time* of a fuel is the time required for a mixture to spontaneously ignite at some given condition. This parameter is a function of the fuel composition, the fuel to air ratio, the pressure, and the mixture temperature. Ignition delay time is of importance to the combustion specialist because it is a direct indication of potential autoignition in the mixing barrel, and it is a useful parameter that defines the chemical kinetic time scale at any temperature, such as in the main burner, thus, playing an important role in the position of the flame relative to the injector tip.

Leaner mixtures tend to have a longer delay time, while higher mixture temperatures and higher pressures tend to shorten the delay time. In a lean premix injector, the flow velocities thus have to be high enough to avoid autoignition inside the injector at the prevailing temperatures. Increasing the content of heavier hydrocarbons in an associated gas leads to a decrease of delay time. This is mainly caused by the non-symmetry of all higher hydrocarbons: Heavy hydrocarbons can be attacked much easier than methane molecules, resulting in reduced ignition delay times (Figure 14).
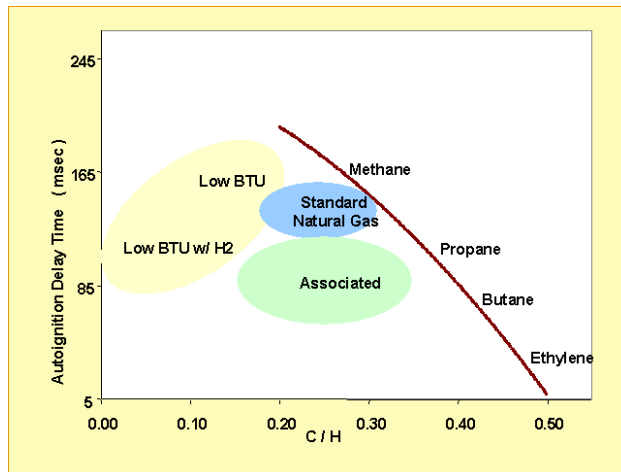
Figure 14: Autoignition Delay Time Depending on Fuel Constituents

In general, the characteristic kinetic times decrease with the addition of hydrogen, with the lowest times (and hence faster chemical kinetics) corresponding to mixtures of CO and H_2. For the ignition times (given in milliseconds) for 1000 K temperatures, the longest times (and hence slower chemical kinetics) are attributed to the mixtures containing mostly methane. Similar conclusions can be drawn for the higher temperature (1400 K) conditions. For example, CH4- only mixtures ignite at approximately 800 µs at 1400 K, while most H_2- and CO-based mixtures ignite in less than 10 µs (Lieuwen et al.). In general, few data are available for specific mixtures, and engine specific tests are often necessary to avoid problems.

Another important parameter is the *ratio of flammability limits*. In the combustor, the fuel and air must be continually burned to keep the engine running. When the flame in the combustor is extinguished it is called a flameout or blowout. The fuel to air ratio changes with the engine load, as described earlier. In order to prevent flameout the combustor must support combustion over a range of fuel to air ratios. Each fuel composition has its own flammability range (Ratio of Flammability Limits). If the engine required fuel-to-air ratio range is equal to or larger than the fuel flammability range, then, at some point, the engine will experience flameout and will not be able to operate at that point. Knowing the ratio of flammability limits allows a decision whether the fuel composition has a broad enough flammability range to support combustion for all operating points of the engine. The *ratio of flammability limits* is defined as the upper flammability limit divided by the lower flammability limit. The upper flammability limit is the maximum fuel percentage (volumetric) mixed with air that will still light and burn when exposed to a spark or other ignition source. The lower is the minimum fuel percentage to sustain combustion. Different gases have different ranges of flammability. Hydrogen, for example, will burn with as little as 4 percent fuel and 96 percent air (lower limit) and as much as 75 percent fuel and 25 percent air (upper limit). Outside of this range (less than 4 percent or more than 75 percent fuel) the hydrogen-air mixture will not burn. Therefore, hydrogen has a ratio of flammability limits of 75/4 equal to 18. On the other hand a typical coal gas has a ratio of 13. 5/5. 3 equal to 2. 5. Coal gas typically contains methane, CO_2, and CO. CO_2 is not combustible. Therefore, if the coal gas contains too much CO_2, the flammability range will decrease and this ratio of flammability limits will decrease as well.

The *stoichiometric flame temperature* impacts the amount of NO_X emissions. It is also a parameter to help verify that a given fuel composition can be burned at all gas turbine operating loads and idle. Across the flammability range, the mixtures of fuel and air will burn at different temperatures. As the fuel-to-air ratio is increased from the lower flammability limit, the flame temperature will increase. Upon further increase in the ratio, a point will be reached where the amount of fuel and air will be perfectly matched so that all the oxygen in the air is reacted with all the fuel - this is called the stoichiometric fuel-to-air ratio. It also corresponds to the maximum flame temperature. As the fuel-to-air ratio is increased further still, the flame temperature starts to decrease and continues to decrease until the upper flammability limit is reached. In standard combustion systems, with a very heterogeneous mixture, the flame temperature is close to the stoichiometric flame temperature. The flame temperature has a significant impact on the NO_X production rate (Figure 15). Fuel gas with a high amount of non-combustibles will usually cause low flame temperatures, while fuel gas containing amounts of hydrogen, carbon monoxide, or heavier hydrocarbons, will exhibit higher flame temperatures. Therefore, a fuel gas with a high amount of diluents will yield lower NO_X emissions even in standard combustion systems.
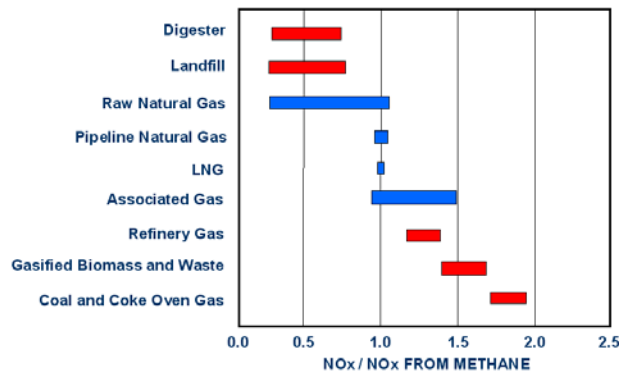
Figure 15: Impact of Fuel Gas on NO$_x$ Emissions

Combustion instability refers to damaging pressure oscillations associated with oscillations in the combustion heat release rate. These oscillations cause wear and damage to combustor components and, in extreme cases, can cause liberation of pieces into the hot gas path, damaging downstream turbine components. Combustion instability issues are highlighted here because the conditions under which they occur can be influenced by the fuel composition (Lieuwen et al., 2006). A necessary, but not sufficient, condition for instability to occur is that the unsteady pressure and heat release oscillations must be in phase (or, more precisely, that their phase difference is less than ninety degrees). Fuel composition variations affect combustion instabilities by altering this phase angle.

In order to understand how variations in fuel composition affect the phase difference between pressure and heat release fluctuations, it is necessary to consider the specific mechanism responsible for the instability. Two mechanisms known to be particularly significant in premixed systems are fuel/air ratio oscillations and vortex shedding. In the former mechanism, acoustic oscillations in the premixer section cause fluctuations in the fuel and/or air supply rates, thus, producing a reactive mixture whose equivalence ratio varies periodically in time. The resulting mixture fluctuation is convected to the flame where it produces heat release oscillations that drive the instability. The coupling of the premixer acoustics with the fuel system is affected by the pressure drop across the fuel injector. The vortex shedding mechanism, as its name suggests, is due to large scale, coherent vortical structures. These structures are the result of flow separation from flameholders and rapid expansions, as well as vortex breakdown in swirling flows. They are convected by the flow to the flame where they distort the flame front and thereby cause the rate of heat release to change. Fuel/air ratio oscillations and vortex shedding become important when the resulting heat release perturbation is in phase with the pressure fluctuation.

Corrosion in the Gas Turbine Hot Section

Also called high temperature corrosion, *hot corrosion* requires the interaction of the metal surface with another chemical substance at elevated temperatures. Hot corrosion is a form of accelerated oxidation that is produced by the chemical reaction between a component and molten salts deposited on its surface. Hot corrosion comprises a complex series of chemical reactions, making corrosion rates very difficult to predict. It is the accelerated oxidation of alloys caused by the deposit of salts (e. g., Na$_2$SO$_4$). Type I or high-temperature hot corrosion, occurs at a temperature range of 730 to 950°C. Type II or low temperature hot corrosion occurs at a temperature range of 550 to 730°C. Inside gas turbines, hot corrosion is probably the most potent cause for premature metal weakening and failure. For example, hot stress corrosion cracking of turbine blades, which is effectively the continuous weakening of the blade metal surface from hot corrosion and the subsequent growth of subsurface cracks under mechanical stresses, has been the recognized root cause for many aircraft and ground based gas turbine engine failures. Hot Corrosion requires the interaction of the metal surface with sodium sulfate or potassium sulfate, salts that can form in gas turbines from the reaction of sulfur oxides, water, and sodium chloride (salt) or potassium chloride, respectively. Hot corrosion is caused by the diffusion of sulfur from the molten sodium sulfate into the metal substrate which prevents the formation of the protective oxidation film and results in rapid removal of surface metal. For hot corrosion to occur, both sulfur and salt (e. g., sodium chloride or potassium chloride) have to be present in the very hot gas stream in and downstream of the combustor. Sulfur and salt can come from the inlet air, from the fuel, or water (if water is injected). Liquid fuel contaminants, such as vanadium or lead, also assist hot corrosion, and will be covered in the section about liquid fuels.

Sulfidation, is the reaction between a metal and a sulfur and oxygen-containing atmosphere to form sulfides and/or oxides. This means, in particular, that sulfidation only requires the presence of sulfur in the combustion air or the fuel, but it does not require the presence of sodium or potassium. In essence, sulfidation attack is a form of accelerated oxidation resulting in rapid degradation of the substrate material due to loss of corrosion protection. During oxidation, protective oxide scales can form; the metallic sulfides formed are not protective. This accounts for the rapid rate of degradation produced by sulfidation attack.

Liquid Fuels

In certain regions of the world natural gas is either not available or in short supply, and in these situations the local power producers must turn to alternative liquid fuels with qualities ranging from light distillates to heavy residual-grade oils or un-refined crude oils. Liquid distillates such as diesel oil or kerosene are also widely used as secondary back-up fuels in dual-fuel applications, which is often a contractual obligation in case of disruptions to natural gas supplies. Dual-fuel capability may also enable the primary fuel (i. e., natural gas) to be purchased at a more favorable price (Meher-Homji et al., 2010).

Fuels should be appropriate for the intended application and, especially in the case of low-grade fuels, must also be suitable for the particular gas turbine model. Residual-grade oils and crude oils will require additional balance of plant and on-site treatment programs, and these items also need to be carefully considered during the initial planning and design stages. The use of residual oil and crude oil in gas turbine applications and the underlying requirements for fuel treatment has been reviewed by Bromley (1986, 2006). BOP design considerations and the importance of realistic fuel specifications for heavy fuel projects are described by Moliere et al, 2002. A detailed treatment of fuels and combustion is provided in Meher-Homji et al., (2010).

Distillates and residual-grade fuels originate in the oil refinery, and are produced from the fractionation of crude oil. The lower boiling point distillates are relatively free of sulfur and trace metals, but contaminant concentrations increase in the higher boiling point fractions toward the bottom of the distillation column. In fact, these components become concentrated in the "residuum", so that residual-grade oils contain higher contaminant levels than the crude oil from which they were produced. This is an important consideration for gas turbine applications, because trace metal impurities create ash deposits during combustion and, unless treated, are responsible for various high-temperature corrosion mechanisms. Other properties such as density and viscosity also increase on moving down the distillation column.

Distillates are classified as *"clean"* fuels because of the absence of ash-forming trace metal impurities. Combustion characteristics are similar to natural gas and, without considering price, they are the most logical fuel alternative.

Several different grades of distillate are available and those most commonly used as gas turbine fuels are *No. 2 distillate* (also known as No. 2 diesel oil, No. 2 fuel oil or heating oil) and *kerosene* – which in Britain is often called paraffin. *Naphtha* is also gaining popularity as a gas turbine fuel, and is actually the generic name for a group of volatile and low boiling point distillates normally used as a feedstock for gasoline production. However, depending on the desired product mix at a particular refinery, portions of the naphtha fraction can be sold directly as fuel. Due to the high volatility of naphtha, explosion-proof fuel handling systems are needed and have been developed for this purpose, and many successful gas turbine applications now exist around the world including the U. S. Probably the largest use of naphtha is in India, where it is burned as the primary fuel in almost all gas turbines in that country.

It also should be noted that the fuels listed under No. 2 distillate may contain different amounts of sulfur. US Highway Diesel No. 2 contains 15ppm sulfur, while many other fuels in this category contain significantly higher levels of sulfur.

Distillates normally do not require additional treatment at the gas turbine power plant, but certain fuel properties can influence reliable operation. For example, some diesel oils and kerosenes have relatively high wax content and (more importantly) high wax melting temperatures, so fuel heating systems must be designed to prevent wax crystallization and filter plugging. Also, naphtha and certain kerosenes are known to have poor lubricating properties, and lubricity improvement fuel additives are often needed to protect critical components such as fuel pumps and flow dividers.

Distillate Contamination

It should always be remembered that "clean liquid fuels" can also become accidentally contaminated during delivery, such as by seawater contact from marine transportation. Unfortunately this is an all too common occurrence, and numerous gas turbine blade failures (caused by sulfidation corrosion) have been reported that relate directly to sodium-contamination of distillates. Ironically, the potential for hot corrosion with distillate fuels is greater than with residual grade oils or crude oils. This is because ash-forming trace metals are anticipated in heavy fuels, so treatment programs are always applied at the power plant. However, distillates are often assumed to be contaminant-free, so fuel quality monitoring may not be as diligent and fuel treatment systems may not be installed. Furthermore, gas turbine firing temperature is normally higher for distillate fuels and protective blade coatings may not be applied, so the risk and consequence of hot corrosion is higher (Figure 16).

The possibility of sodium contamination during the marine transportation of fuels results mainly from the fact that sea water is used as "ballast"; i. e., to adjust the buoyancy of an empty tanker after

discharging its cargo. Most of the new, large, oceangoing super tankers are now equipped with segregated (dedicated) ballast tanks, but many older vessels and coastal barges still use their product tanks for sea water ballast. Note that OEM specifications for sodium plus potassium (actually for total alkali metals) in gas turbine fuels range from as little as 0. 1 ppm up to 1. 0 ppm maximum, depending on the gas turbine model, and it does not take much sea water to exceed these limits. In fact, *8 gallons of sea water in 1 million gallons of distillate will contribute 0. 11 ppm Na + K.*

Note, also, that in coastal or marine locations, the ingestion of airborne sea salt can also initiate hot corrosion regardless of fuel type, and this risk applies equally to natural gas or liquid fuel applications.

Fuel contamination with traces of lead (Pb) and zinc (Zn) has also been reported, and which also causes high temperature corrosion of gas turbine blades. These metals are not natural components of petroleum and contamination can usually be explained by contact with leaded-gasoline or (respectively) with galvanized materials.

Figure 16: Hot Corrosion on Turbine Blades after about 1,000 hrs of Operation on Distillate Fuel Containing 2 ppm Sodium from Sea Water Contamination (Courtesy Turbotect Ltd.)

Residual-Grade Oils and Crude Oils

These fuels are classified as "contaminated" because they contain relatively high concentrations of various trace metals (sodium, vanadium, etc.) and other impurities such as solids and sediments. Trace metals create ash deposits during combustion, which impacts gas turbine performance and availability but can also lead to serious high temperature corrosion issues unless fuel treatment programs are applied at the power plant. Such treatment programs use a centrifugal separation processes to remove those contaminants that are removable, such as water-

soluble sodium salts and water-extractable solids. Then, special chemical additives are injected to inhibit the corrosive effect of oil-soluble trace metals (primarily vanadium) remaining in the fuel.

Residual oils are usually blends of several different refinery residues (i. e., from atmospheric distillation, vacuum distillation, and various cracking processes, etc.). Their properties vary tremendously depending on the crude oil feed-stock and the degree of fractionation and processing within a particular refinery. Generally, residual oil quality around the world is deteriorating. This is simply because refineries try to maximize their yield of light distillates and high-value products such as gasoline. The net effect is that residual fractions become heavier, more viscous, and more contaminated with trace metals.

As a result, so-called "straight-run" residuals (typically termed "No. 6" grade) are normally not sold without some degree of additional blending with a light- or middle-distillate, in order to meet minimum sales specifications for the major markets – such as maximum sulfur or maximum viscosity. However, these basic sales specifications may not adequately address all important items needed for gas turbine applications - such as trace metal content, which is usually limited to a maximum of 100 ppm by the OEMs. In many cases, therefore, it may be necessary to establish a project-specific fuel specification with the supply refinery, which may involve additional distillate blending to further reduce trace metal content; but of course this will also increase the price of the residual fuel oil.

Residual oils coming from different (or unknown) source refineries should also be carefully monitored for stability and compatibility before mixing different batches. This issue relates to asphaltenes (a heavy bitumen-type component of petroleum), and the fact that asphaltenes can be **destabilized** if oils with incompatible chemistries are inadvertently blended. If destabilization occurs, asphaltenes will agglomerate (flocculate) and eventually precipitate out of the oil as sludge. This can result in very serious fuel system problems such as the plugging of fuel filters, flow-dividers and burner nozzles, etc.

Various names and abbreviations are used around the world to describe residual-grade fuels including "bunker fuel", "furnace oil", "mazut", "LSHS" (low sulfur heavy stock), "LSWR" (low sulfur waxy residual), etc. The most common term within the gas turbine industry is "HFO" (heavy fuel oil).

Crude oil properties vary throughout the oil-producing countries of the world, but generally they remain relatively constant and specific to a particular

oil field or group of oil fields within a region. Crude oils can be "heavy" or "light" (referring to their density), "sweet" or "sour" (relating to their sulfur content), and can also have different chemical natures that influence their chemical properties and the type of products derived during refinery processing.

Gas Turbine Considerations with Liquid Fuels

The type and model of gas turbine must be suitable for the particular grade of oil, and the application must be supported by the OEM. Heavy-duty engines with lower firing temperatures are used for burning residual oil and crude oil, and also for distillates if fuel contamination is expected

De-rating is often recommended for ash-forming fuels and turbine inlet temperature (TIT) at base load may be limited to a maximum of *about* 1050°C (1922°F) or lower. This is only a guideline, however, and actual OEM recommendations will vary according to the contractual fuel specification, blade cooling, metallurgy, hot gas path coatings, and the particular GT model. There are also slight differences within the industry as to the specific definition of "turbine inlet temperature" and/or "firing temperature", and the actual position in the hot gas path where this temperature is defined. For example, variances of about 30 to 40°C can be accounted for if this temperature is defined as being just upstream of the 1st-stage turbine inlet nozzle, immediately after the 1st-stage inlet nozzle, or at a point between the first-stage nozzle and first-stage rotating blade. In all cases, the specific OEM recommendations should be followed. The main reason for de-rating and limiting TIT is to minimize the formation of hard ash deposits on turbine blades, which is a function of ash chemistry and the prevailing temperature at which the ash is exposed. Higher firing temperatures create harder and more compact deposits that are difficult to remove.

Advance technology models and aero-derivative turbines are normally restricted to firing only natural gas or high-quality clean distillates. This said, the possibility of distillate contamination and/or the ingestion of airborne sea salt become very critical considerations for these higher firing temperature engines.

High Temperature Corrosion and Liquid Fuel Treatment

Residual-grade fuel oils and crude oils are classified as "contaminated" or "ash-forming" fuels because they contain relatively high concentrations of various trace metals that create ash deposits during combustion. Ash fouling impacts gas turbine performance and availability, but can also lead to serious high temperature corrosion problems of hot

gas path (HGP) components unless appropriate fuel treatment programs are applied at the power plant. Such treatment programs use a physical separation processes to remove those contaminants that are removable, and special chemical additives to inhibit the corrosive effect of oil-soluble trace metals that remain in the fuel.

Figure 17: Accelerated Surface Oxidation Caused by Vanadium in Heavy Fuel Oil (Courtesy, Turbotect Ltd.)

Classification and Origin of Liquid Fuel Contaminants

The most common fuel contaminants are classified as being either "water-soluble", "water-extractable" or "oil-soluble". This classification is useful because it gives an indication as to whether contaminants can be removed from the fuel by a purification processes such as fuel washing, or whether they are chemically bound to the oil and will enter the hot gas path.

Sodium (Na), potassium (K) and calcium (Ca) are **water-soluble** contaminants, and result primarily from the entry of underground formation water or seawater during crude oil production. Much of this water is separated in the oilfield via dehydration processes, and salt content is further reduced at the refinery prior to

crude oil distillation. However, some quantity of Na and K always remains in the residual fraction and additional contamination often results from the disposal (into residual oils) of refinery waste streams – which, though not good practice, still commonly happens. Contact with seawater during marine transportation to the power plant will also introduce additional sodium, and can occur with any grade of fuel including distillates. Water-soluble trace metals can be removed (or at least significantly reduced) by a physical separation process known as fuel washing.

Heavy oils also contain various solids and sediments that can lead to filter plugging and erosion problems. These contaminants are classified as "water-extractable" because they are normally associated with the water phase and can be removed during the fuel washing process. Typical materials include sand, silt, rust, scale, or even asphaltic sludges that may have separated from the petroleum. Refinery processing can also introduce catalyst fines (cat fines), which are small and very abrasive particles containing alumina (Al_2O_3) and silica (SiO_2). This material is used as an inert catalyst support in refinery cracking units, but if it contaminates residual oils it can be very abrasive to gas turbine fuel system components such as pumps and flow-dividers.

Vanadium (V) and nickel (Ni) are natural oil-soluble components of most crude oils. They are present as organo-metallic complexes known as porphyrins, and are chemically bound to the heavy asphaltic fractions of the petroleum. Concentrations can range from a few parts per million (ppm) to several hundred ppm according to the type, age and geographic location of the crude oil Refinery distillation has the effect of concentrating these trace metals in the high-boiling point residue, so that levels found in residual-grade oils are considerably higher than in the crude oil feed-stock.

Effect of Trace Metal Contaminants

All trace metals in fuels are undesirable because they create ash compounds during combustion and these mixtures of oxides and sulfates will deposit within the hot gas path. Ash fouling reduces turbine output, and in severe cases, it can also cause plugging of critical air-cooling channels on blades and vanes. Various high-temperature corrosion mechanisms can also be initiated if ash deposits melt (and remain in the liquid phase) on component surfaces. However, if ash melting point is sufficiently high that deposits remain in the solid state, these type corrosion processes cannot proceed. Thus, ash melting point and blade surface temperature are important parameters that jointly determine whether corrosion will occur, and also influence how it can be controlled.

Several different types of high temperature corrosion are possible, and more detailed descriptions can be found in Stringer (1977), and in Stalder and Huber (2000). For gas turbines firing residual-grade oil, crude oil or contaminated distillates the two most important corrosion processes are known as *sulfidation corrosion* and *vanadic oxidation*.

Vanadic Oxidation

This type of corrosion can occur whenever fuels containing vanadium (V) are burned, such as residual-grade oils and crude oils. It is caused by molten ash deposits of vanadium pentoxide (V_2O_5), melting point $675^{\circ}C$ ($1,247^{\circ}F$), which condense on blade surfaces and rapidly destroy protective oxide films. This leads to further oxidation of the alloy surface and further destruction, etc., so that normal oxidation rates are **accelerated** and the service life of components and coatings is significantly reduced. An example of vanadium-induced surface oxidation is shown in Figure 17. The accumulation of ash deposits and hard corrosion products can also result in serious vibration and balancing issues. Similar surface oxidation mechanisms are also initiated by traces of lead (Pb) and zinc (Zn) in gas turbine fuels.

It is important to note that fuels containing both vanadium *and* sodium can generate a variety of mixed oxides known as sodium vanadates, and these ash mixtures can have extremely low melting points around $532^{\circ}C$ ($990^{\circ}F$). This significantly increases the risk of molten-ash corrosion (even with de-rated firing temperatures), and is the main reason why water-soluble sodium salts are reduced to extremely low levels during the fuel treatment process.

Fuel Treatment to Control High Temperature Corrosion

Treatment programs for crude oils and residual-grade oils involve physical separation processes to reduce water-soluble sodium and potassium salts to acceptable low levels. Chemical additives containing magnesium are then applied to inhibit the corrosive effect of vanadium which remains in the fuel. Overall design of the treatment program must be based on the contractual specification of the raw (untreated) fuel that will be received, as well as the treated fuel specification for the particular gas turbine model.

The effect of fuel contaminants and their impact on high temperature corrosion is described by Moliere et al (1995) and Johnson (1996). Valuable early studies in this field that are still valid today are reported by Felix (1977, 1979). A useful overview of gas turbine fuel treatment and the use of magnesium-based additives can be found in Zubler and Stalder (1998).

Removal of Sodium and Potassium

A process known as "fuel washing" is used and involves the injection of a quantity of fresh wash water into the raw fuel to dilute and extract water-soluble salts and water-wettable solids. After mixing, the emulsified oil and water phases are then re-separated to produce outlet streams of treated (i. e., washed) fuel and effluent water, which now contains the extracted salts and solids. The most widely used separation technology for gas turbine fuel treatment systems involves centrifuges, which increase oil-water separation rate by increasing gravitational force.

Maximum allowed limits for sodium and potassium (Na+K) depend on the type of gas turbine involved, and there is some variance between the different OEMs. However, typical guidelines are as follows:

- Lower-firing temperature heavy-duty models: 0. 5 to 1. 0 ppm max.
- Higher-firing temperature heavy-duty models: 0. 2 to 0. 5 ppm max.
- Most aero-derivative models: 0. 1 to 0. 5 ppm max.

By definition, these limits apply to "total Na+K" entering the hot gas path from all sources; i. e. from fuel, air and any water or steam that may be injected for NO_x control or power augmentation. As can be seen, these limits are very strict.

Additive Treatment to Control Vanadic Oxidation

Vanadium is not removed in the fuel washing process, so chemical additives based on magnesium (Mg) are used to inhibit the vanadic oxidation process. They function by modifying ash composition to increase ash melting point, thus ensuring that deposits on turbine blades do not melt and remain safely in the solid state. The main ash component, without Mg, is vanadium pentoxide (V_2O_5), with a low melting point of 675^oC (1247^oF), and this ash would be molten at typical blade temperatures. However, with the addition of sufficient magnesium a different ash component is created, called magnesium orthovanadate ($Mg_3V_2O_8$). This mixed-oxide has a significantly higher melting point of about 1243^oC (2270^oF) and remains solid at typical blade temperatures.

Assuming Na+K has been reduced to OEM specification limits as outlined above, a minimum treatment ratio of Mg/V=3 is normally recommended; i. e., the addition of 3 ppm magnesium for each 1 ppm vanadium in the fuel on a wt/wt basis. This treatment formula may need to be adjusted if other oil-soluble trace metals such as nickel, lead or zinc are present, and specific guidelines set by the particular OEM should be followed. Nickel, for example, is not regarded as a corrosion-promoting contaminant because it forms relatively-high melting point ash deposits. However, nickel interferes with the vanadium inhibition mechanism by combining with some of the magnesium, so that higher additive dosage may be required.

Competing reactions with fuel sulfur also occur and create magnesium sulfate ($MgSO_4$) as an additional ash component, and this is another reason why sufficient Mg must be injected. Actually, formation of $MgSO_4$ is very important, because it is the only water-soluble component of the ash mixture and enables deposits to be removed by periodic water-washing of the hot gas path. However, if blade temperature is too high, $MgSO_4$ decomposes to magnesium oxide (MgO), and ash deposits become harder and much more difficult to remove. Note that this is the main reason why turbine firing temperature is limited (as discussed above) when burning ash-forming fuels. Important thermodynamic studies on ash composition and the impact of blade temperature are reported by Lay (1974).

Key Elements in the Successful Use of Liquid Fuels

In the absence of natural gas, low-grade and lower-cost residual oils or crude oils can be burned successfully in heavy-duty gas turbines, and numerous examples exist around the world. In many cases, the local population would have been without electricity if these projects had not been undertaken. Although these type projects are often considered to be risky, it is a fact that more high-temperature corrosion failures have occurred with contaminated distillate fuels than with heavy fuels – simply because distillates are "assumed" to be clean and often they are not. Heavy fuels are known to be contaminated and are treated accordingly. Key success factors for heavy fuel applications include:

- The selected fuel must be appropriate for the particular gas turbine model, and vice-versa.
- The consequences of de-rated performance and lower availability must be clearly understood at the planning stage, and installed capacity should be designed accordingly.
- Realistic and detailed raw fuel specifications must be established early in the project, so that suitable fuel treatment systems can be designed and included in balance of plant (BOP) engineering.
- High-quality and field-proven fuel additives should be selected and dosed at the recommended treatment ratio.
- A well-equipped site laboratory and experienced laboratory staff is essential for heavy fuel operations.

- Untreated and treated fuel quality should be monitored regularly and routinely to ensure continued compliance with fuel purchase contracts and OEM specifications.

DEGRADATION AND WATER WASHING

The fouling of axial flow compressors is a serious operating problem and its control is of supreme importance to gas turbine operators especially in the deregulated and highly competitive power market. It is also significant in the mechanical drive market where a loss in gas turbine output directly affects plant throughput. Foulants in the ppm range can cause deposits on blading, resulting in severe performance deterioration. The effect of compressor fouling is a drop in airflow and compressor isentropic efficiency, which results in a "rematching" of the gas turbine and compressor causing a drop in power output and thermal efficiency. In extreme cases, fouling can also result in surge problems, as it tends to move the compressor surge line to the right, i. e., towards the operating line. Details on compressor fouling, and its causes detection and control may be found in Meher-Homji and Bromley (2004), as well as in Kurz and Brun (2012).

Estimates have placed fouling as being responsible for 70 to 85 percent of all gas turbine performance losses accumulated during operation. Output losses between 2 percent (under favorable conditions) and 15 to 20 percent (under adverse conditions) have been experienced.

Gas turbines ingest extremely large quantities of air, with larger gas turbines having airflow rates of as high as 1,500 lbs/sec (680 kg/sec). A scatter plot of the airflow rate versus power for 67 gas turbines is presented in Figure 18.
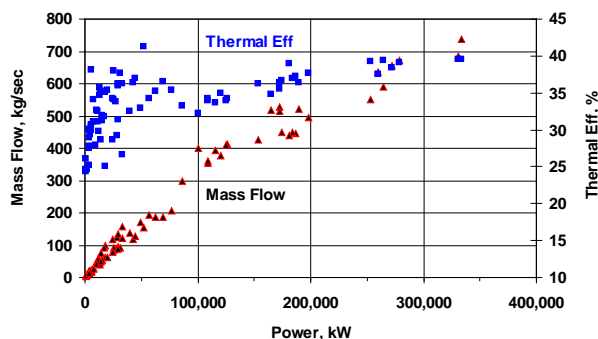

Figure 18: Airflow Versus Power for 67 Different Industrial Gas Turbines

In a gas turbine, approximately 50-60 percent of the total work produced in the turbine is consumed by its axial compressor. Consequently, maintaining a high compressor efficiency is important for the plant's revenue stream. Parasitic losses and mechanical efficiency have also been considered in the model, which accounts for the output being somewhat less than the difference between the turbine and compressor work. It is useful to present this type of data to operators to convince them of the importance of maintaining clean axial compressors by both high quality air filtration and appropriate washing techniques.

Solids or condensing particles in the air and in the combustion gases can precipitate on the rotating and stationary blades causing changes in aerodynamic profile, reducing the compressor mass flow rate and affecting the flow coefficient and efficiency; thus, reducing the unit's overall performance. Further, contaminated air can cause a host of problems that include erosion, fouling, corrosion and, in some cases, plugging of hot section cooling passages. There is also a close co-relation between mechanical reliability and fouling deterioration, and an example is the damaging effects of fouling on blading integrity as discussed in the following sections. This is another important reason to keep the compressor clean. Some typical photos of fouled compressors are shown in Figures 19 through 22.
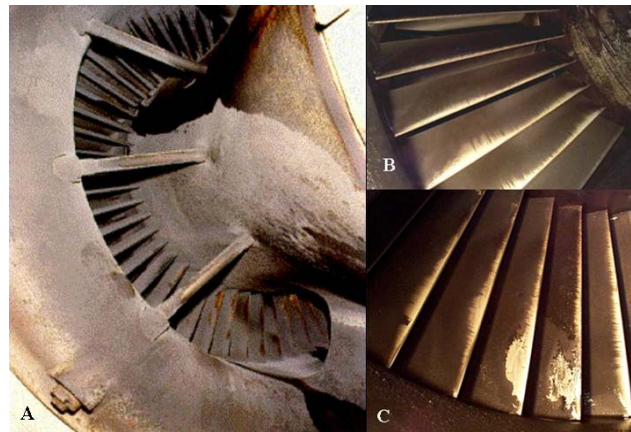

Figure 19: Examples of Fouled Compressor Blades: (a) Heavily-Fouled Air Inlet Bell-Mouth and Blading on a 35 MW Gas Turbine; (b) Oily Deposits on Blading; (c) Compressor Blades Fouled with a Mixture of Salts and Oil (Courtesy, Turbotect Ltd.)

Figure 20: Oily Deposits on Axial Compressor Blades from No. 1 Bearing Oil Leakage on a Large Heavy Duty Gas Turbine
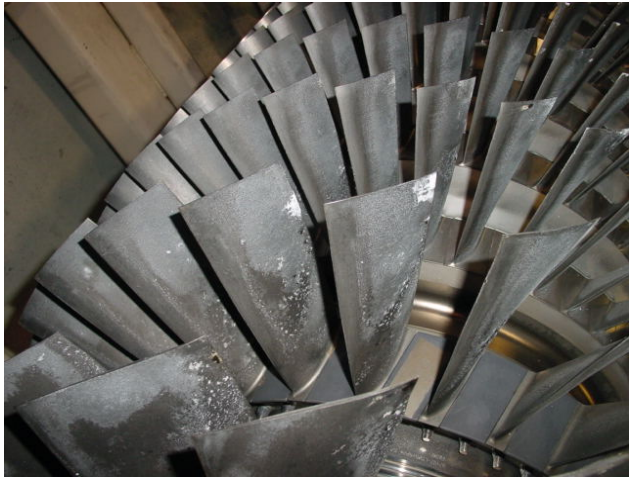

Figure 21: Salt Deposits on Compressor Blades(Courtesy, Turbotect Ltd.)

Figure 22: Low Solubility Deposits on Compressor Blades(Courtesy, Turbotect Ltd.)

Underlying Causes of Fouling

Experience has shown that axial compressors will foul in most operating environments; be they industrial, rural or marine. There are a wide range of industrial pollutants and a range of environmental conditions (fog, rain, humidity) that play a part in the fouling process.

Compressor fouling is typically caused by:

- Airborne Salt
- Industrial Pollution – hydrocarbons, fly ash, smog, exhaust emissions from traffic etc. This causes a grimy coating on the early compressor stages and can get "baked on" in the latter stages because of the high compressor discharge temperatures (This is especially true of high pressure ratio compressors).
- Ingestion of Gas Turbine Exhaust or Lube Oil Tank Vapors.
- Mineral Deposits such as limestone, coal dust and cement dust.
- Airborne Materials - soil, dust, sand, chemical fertilizers, insecticides, and plant matter.
- Insects – This can be a serious problem in tropical environments.
- Internal Gas Turbine Oil Leaks – Leakage from the front bearing of the axial compressor is a common cause. Oil leaks combined with dirt ingestion cause heavy fouling problems.
- Impure Water from Evaporative Coolers (carryover) or inlet fogging.
- Spray Paint that is ingested.
- Vapor plumes from adjacent cooling towers.

Often, the inlet struts and IGVs get severely fouled. Hand cleaning the IGVs and first stage will restore a considerable amount of performance. However, some cleaning methods simply transport dirt from the front stages to rear stages.

Ambient air can be contaminated by solids, liquids, and gases. Air loadings can be defined in mg/m^3, grains/1000 ft^3 or ppm (mass of contaminant per unit mass of air). In general, particles up to 10 microns cause fouling, but not erosion. Particles above 10 to 20 microns cause blading erosion. Some typical air loadings are as follows:

- Country 0. 01 - 0. 1 ppm by weight
- Coastal 0. 01 - 0. 1 ppm by weight
- Industrial 0. 1 - 10 ppm by weight
- Desert 0. 1 - 700 ppm by weight

Felix and Strittmatter (1979) have detailed the type of analysis that should be done at a gas turbine

plant site. In most industrial areas, the air quality can create quite acidic conditions in the axial compressor.

The importance of climatic conditions, such as rain showers or relative humidity cannot be overemphasized. Several operators have reported dramatic drops in gas turbine output coincident with rain showers. Often, air filters will exhibit a sudden growth in differential pressure as the filters get saturated with water due to high humidity. Under certain conditions, the filter may suddenly unload into the airflow causing rapid compressor fouling.

It is instructive to investigate the sensitivity of compressor fouling deterioration on simple cycle gas turbine performance. To this end, simulation runs using GTPRO software have been made for a 40 MW-Class heavy duty gas turbine in simple cycle configuration. Runs were made with natural gas fuel with an LHV of 50046 KJ/kg (21,518 Btu/lb) and with typical inlet and outlet pressure drops 100 & 125 mm WG (4 and 5 inch WG) respectively. The machine has an ISO pressure ratio of 11. 8:1 and a mass flow rate of 138 kg/sec (304lbs/sec) and a firing temperature of 1104°C (2020°F).

The simulation was run at an ambient temperature of 15°C (59°F), and imposing deterioration steps in the following sequence:

- Step 1: New and Clean, Mass flow drop = 0%, Comp. efficiency drop = 0%
- Step 2: Mass flow drop = 1%, Comp. efficiency drop = 0. 833%
- Step 3: Mass flow drop = 2%, Comp. efficiency drop = 1. 67%
- Step 4: Mass flow drop = 3%, Comp. efficiency drop = 2. 5%
- Step 5: Mass flow drop = 4%, Comp. efficiency drop = 3. 33%
- Step 6: Mass flow drop = 5%, Comp. efficiency drop = 4. 167%
- Step 7: Mass flow drop = 6%, Comp. efficiency drop = 5%

Output and heat rate variation with the deterioration steps is shown in Figure 23. The output at the end of the 7th deterioration step has dropped 5. 5 MW while the heat rate has increased by 850 Btu/kW hr. On a relative basis, the power deterioration is twice as big as the deterioration in heat rate.
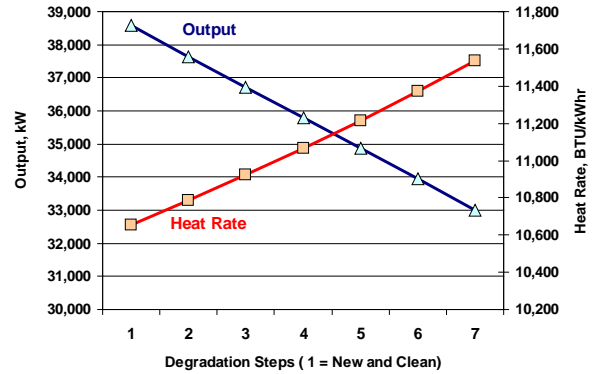

Figure 23: Output and Heat Rate Change with Compressor Degradation Steps Imposed on a 40 MW Class Gas Turbine
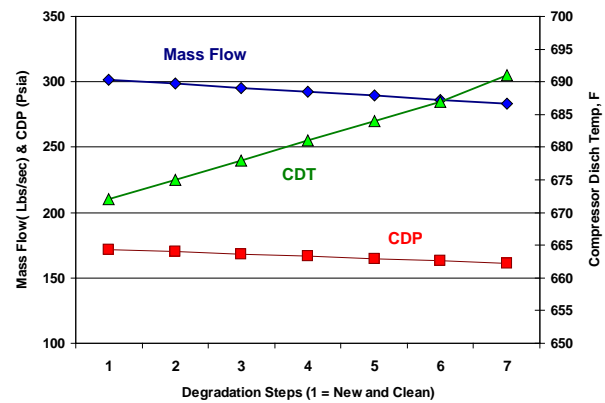
Figure 24: Change in Mass Flow Rate, Compressor Discharge Temperature and Pressure with Compressor Degradation Steps Imposed on a 40 MW Class Gas Turbine

The change in mass flow rate, compressor discharge pressure and compressor discharge temperature corresponding to the simulated deterioration steps is shown in Figure 24.

The drop in efficiency causes the discharge temperature to increase by approximately 10. 6°C (19°F) and the compressor discharge pressure to drop by about 0. 7 bar (10 psia). The variation in axial compressor work, turbine section work, and the output after losses is shown in Figure 25.
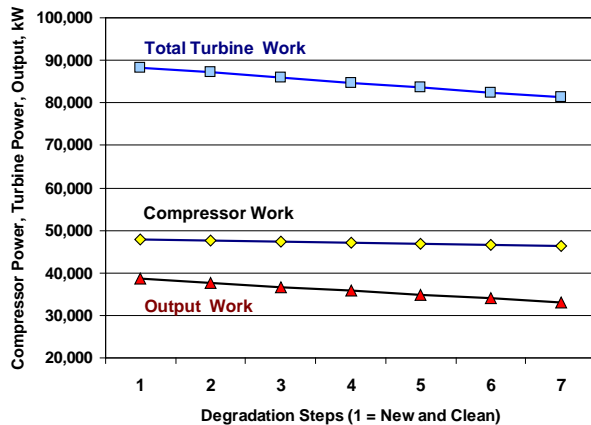
Figure 25: Change in Compressor Work, Turbine Work and Overall Output with Compressor Degradation Steps Imposed on a 40 MW Gas Turbine

Whereas the axial compressor work is seen to drop slightly due to the reduction in mass flow (middle line of the figure), there is a steep drop in the turbine work (upper line in the figure) resulting in a drop in overall gas turbine output of 5. 5 MW. The steep drop in turbine section work is due to the reduced mass flow and the smaller expansion ratio available as a result of the loss in compressor discharge pressure.

NON-RECOVERABLE DEGRADATION

Unrecoverable performance deterioration is the residual deterioration that will exist and detract from gas turbine performance even after the gas turbine has been washed and cleaned. Damage that occurs to the flow path due to erosion, corrosion and increased tip and seal clearances or due to distortion of the casing itself will contribute to this.

During a major overhaul, deteriorated gas turbine components are cleaned or replaced, and airfoils are recoated (compressor and turbine section as needed) and tip and seal clearances restored as close as possible to the initial condition. Even after the overhaul, depending on overhaul procedures, however, there may be some performance loss due to:

- Casing distortion
- Increased flow path surface roughness
- Airfoil untwist
- Increased leakage areas

Dikunchak (1993) estimates the extent of this type of unrecoverable deterioration to be usually less than 1 percent. The extent of the unrecoverable loss will be greater if heavy fuels are being utilized.

Some manufacturers offer overhauls to the extent that the overhauled engine meets the same performance criteria as a new engine. These overhauls in general require the removal of the gas turbine, and the overhaul has to be performed in a dedicated overhaul facility. Engine exchange programs help to minimize downtime if necessary.

Erosion

Due to the presence of air filtration systems, erosion is not a major problem with industrial gas turbines, though it has been a problem in areas where the filtration system could not cope with very large dust and sand loading such as exists during a sandstorm.

Erosion is the abrasive removal of blade material by hard particles such as sand and fly ash, usually greater than 5-10 microns in diameter. Erosion impairs blade aerodynamic performance and mechanical strength. The initial effect of erosion is an increase in surface roughness and a lowering of compressor efficiency. As it progresses, airfoil contour changes occur at the leading and trailing edges and at the blade tip. Thinning of the trailing edge is detrimental to the fatigue strength and can result in blade failure. A significant loss in tip solidity can promote compressor surge. The typical area of metal loss for a rotor blade is at the tip while for a stator it is near the root. Typically, the erosive particles are centrifuged to the outer diameter of the compressor. As a rule of thumb, blade replacement should be considered when loss of cross sectional area exceeds 10-15%.

Hot Section Erosion: Erosive particles entrained in the air or fuel can cause turbine section erosion. The damage is particularly severe if cooling hole blockage occurs which can lead to excessively hot blades and ultimate creep rupture. A reduction in the blade section size further compounds the stress problem. Erosive particles in the fuel can result in nozzle wear resulting in a distorted temperature profile and severe hot spots at the turbine inlet.

Hot Gas Erosion: Apart from *particulate* erosion, there is also the phenomenon of hot gas erosion which results from localized overheating and thermal cycling due to intermittent loss of cooling or a breakdown in the coating. After several cycles, damage takes place and the increased roughness (erosion) worsens the problem. This problem can occur in the first stage nozzle segments at the platforms. Typically the most severely affected parts are those in the hottest gas path (e. g., central to the transition piece).

Hot Corrosion: Also called high temperature corrosion, hot corrosion requires the interaction of the metal surface with another chemical substance at elevated temperatures. Hot corrosion is a form of accelerated oxidation that is produced by the chemical

reaction between a component and molten salts deposited on its surface. Details are covered in the section about fuels. The rate of formation of the sodium and potassium salts necessary for hot corrosion, and thus the rate of hot corrosion, can be controlled by avoiding the presence of sodium or potassium and sulfur in the engine hot section. Sodium or potassium often enter the engine via the combustion air. Therefore, the air filtration system plays an important role. Sulfur, sodium, and potassium can enter the engine via the fuel.

CONTROL OF COMPRESSOR FOULING BY ON LINE AND OFF LINE COMPRESSOR WASHING

Fouling is best controlled by a combination of two methods. The first line of defense is to employ a high quality air filtration system. However, as fouling will inevitably occur, compressor washing should be used to control its impact.

This is an area in which strong and divergent opinions exist. Washing efficacy is so site specific that approaches which work for one site may not be appropriate for another. Controversy is often caused by polarized opinions relating to wash procedures, wash media, and techniques. Some of the highlights are presented below in an attempt to present the overall picture and the practical field experiences of Stalder (1998). Operators must determine the best approach for their gas turbines by trial and error in terms of wash technique, use of on-line washing, which cleaners should be used, and the frequency of washing. This is a complex technical-economical scenario, and also depends on the service that the gas turbines are in. For example, by not having the ability to shut down for crank washes, IPP operators, LNG Operators and merchant power plants may need to be more aggressive in controlling fouling. A useful set of papers relating to compressor washing have been provided in Stalder (1998), Stalder and van Oosten (1994) and Bagshaw (1974).

Several different methods of gas turbine compressor cleaning have been applied over the years, but *"wet cleaning"* has been found to be by far the most effective and economic technique. However, today's sophisticated large industrial engines and blade coatings require appropriately designed cleaning systems to ensure operational safety, reliability and optimum efficiency. Two different wet cleaning techniques are generally applied, known as off-line (crank wash) and on-line cleaning. Under extreme fouling conditions, hand washing of the IGVs may have to be conducted if time permits. During overhauls, hand cleaning of the full axial compressor is most effective. There has also been some recent interest in foam cleaning of gas turbines.

Off-line washing is almost always carried out with the aid of a detergent, and extremely effective power recovery can usually be achieved. However, it is important that the manufacturer's recommendations are followed with respect to water quality, detergent/water ratio and other operating procedures. Typically, wheel space temperatures must be below 200°F to avoid thermal shock, and the off-line water wash is done with the machine on crank. The downtime for a crank wash depends mainly on the time it takes for cooling the engine. Larger, heavy-duty engines can take 8-10 hours to cool, whereas, on light aeroderivative engines, only 1. 5-3 hours may be needed because of the low metal mass. Off-line cleaning is most effective when carried out in several steps that involve the application of a soap and water solution, followed by several rinse cycles using water alone. Each rinse cycle involves the acceleration of the machine to approximately 50% of the starting speed, after which the machine is allowed to coast to a stop. A soaking period between each wash and rinse cycle is also very important, and allows the soapy cleaning fluid to penetrate into the fouling deposits, thus dissolving salts and emulsifying oil and grease components. A useful method of determining the effectiveness of the off-line wash, and perhaps the need for additional wash or rinse cycles, is to collect samples of the effluent water from all available drain ports (Figure 27). The samples can be checked visually for color and clarity (which should improve as dirt is removed), or by a simple conductivity meter to monitor the removal of salts.

On-line washing is now very popular as a means to control fouling by avoiding the problem from developing. The primary objective of on-line washing is to extend the operating period between off-line washes by minimizing the build-up of deposits in the compressor, and thereby reducing the on-going incremental power losses. On-line washing is performed with the unit in full operation, and techniques and wash systems have now evolved to a point where this can be done effectively and safely. Outages or shutdown periods are not required. Depending on the nature of the fouling material, on-line washing is sometimes performed with water alone. In most cases, however, the use of an approved cleaner (detergent) will improve the effectiveness of the washing operation. This is particularly true if the fouling material contains any quantity of oil or grease. Demineralized water quality is almost always specified by the OEMs for on-line washing, to avoid the possibility of introducing harmful trace metal

contaminants (such as Na+K) into the combustion turbine.

Optimal compressor cleaning can normally be achieved by adopting a combined program of regular and routine on-line washing (for example, every few days or weekly), plus periodic off-line washing during planned outages.
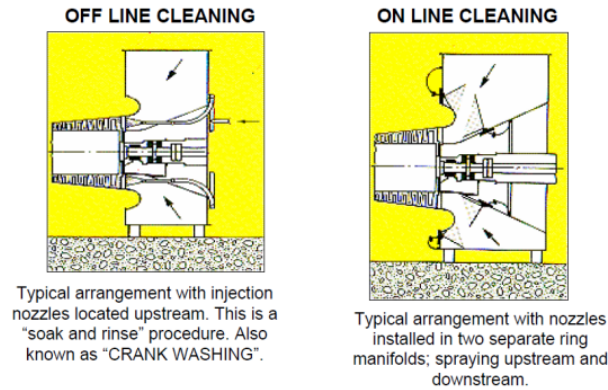
OFF LINE CLEANING   **ON LINE CLEANING**

Typical arrangement with injection nozzles located upstream. This is a "soak and rinse" procedure. Also known as "CRANK WASHING".

Typical arrangement with nozzles installed in two separate ring manifolds; spraying upstream and downstream.

Figure 26: Off Line and On Line Cleaning (Courtesy, Turbotect Ltd.)

Two main types of cleaning agents (detergents) are available for compressor washing and are normally classified as "water-based" or "solvent-based" products. Most of the new-generation products contain surfactants, wetting agents and emulsifiers, and involve either an aqueous or petroleum-based solvent system. Both products are normally supplied as concentrates, and are diluted on-site with water (typically one part cleaner with four parts water) to produce the cleaning fluid. Solvent-based cleaners have traditionally been recognized as being more effective in removing oil and grease deposits, but certain new-generation water-based cleaners are formulated to be equally effective. Most water-based products also have the advantage of being biodegradable, which is an increasingly important requirement within this industry.

Off Line (On-Crank) Washing

The basic objectives of off-line cleaning are to clean a dirty compressor and to **restore** power and efficiency to virtually "new & clean" values. When performed correctly, and provided the operating period between off-line washing is not too long (site specific), this type of cleaning will typically restore virtually 100% of the lost power and efficiency attributed to compressor fouling. However, irrespective of the compressor performance degradation actually encountered, experience has indicated that users of both base-load and peaking gas turbines should incorporate a minimum of three or four off-line compressor cleanings per year in order to

remove the salt laden deposits on the downstream stages.

Off-line wet cleaning (also known as crank washing) is a typical "soak and rinse" procedure for which the gas turbine must be shut down and cooled. The compressor is rotated at crank-speed while a cleaning fluid is injected via nozzles or jet lances. Hand-held jet lances were widely used in the past and are still fairly popular with some operators. However, permanently mounted off-line nozzle systems installed in the air intake plenum are now preferred, and are generally offered as standard by most of the major turbine manufacturers. Nozzle design, system operating pressure, and total mass flow parameters vary widely, however, between the different manufacturers.

The injected cleaning fluid is normally a mixture of chemical detergent and water. Both solvent-based detergents and water-based products are used, depending mainly on the type of fouling material found in the compressor and local plant experience.

After a soaking period the compressor is rinsed with a quantity of fresh water. The amount of rinse water required and the number of rinse cycles vary from site to site, according to the gas turbine model and the amount of dirt removed during the off-line wash. Note that demineralized water is usually not specified for off-line cleaning and fresh water quality is normally acceptable. Effluent water drained from the compressor has to be disposed of according to local regulations.

Typical water quality requirements for an off-line wash are:

- Total Solids (dissolved and undissolved) ≤ 100 ppm
- Total alkali metals (Na, K) ≤ 25 ppm
- Other metals which may promote hot corrosion (V, Pb) ≤ 1 ppm
- pH 6. 5-7. 5

This water would be used for cleaner dilution and also for rinsing.

Off-line crank washing systems should be designed to achieve the highest washing efficiency with the smallest injection mass flow. This is important for the following reasons:

- Gas Turbine users are interested in minimizing the quantity of effluent water to be disposed of.
- Some users claim that off-line water effluent is transported up to the exhaust during the wash procedure, and may wet and soak into the

expansion joint fabric - resulting in damage of the expansion joint by lowering its insulation properties.

- A lower off-line injection mass flow will also reduce the potential risk of trace metal contamination in exhaust systems, where selective catalytic reactors (SCR) for NOx reduction or CO catalysts are installed.
- A smaller off-line injection mass flow will significantly reduce the required size, volume and cost of washing skids and the overall water and cleaner consumption.

Important Considerations During Off Line Washing

Wetting of IGVs: Effective wetting of the IGV's suction area can be achieved by using full cone jet spray nozzles. The number of nozzles will be defined by the area to be wetted, which is usually the area between two intake struts. The necessary off-line injection mass flow characteristic will, therefore, be determined by the area to be wetted and impacted by the jet spray, and the distance between nozzles and the IGVs. The injection pressure is generally between 5. 5 to 6 bar (80 to 87 psi). As spray jet trajectory is subject to gravity, the nozzle should be designed to provide an adjustment of up to five degrees to compensate for the gravity effect. Crank washing (soaking) and rinsing can be considered as a mechanical "erosion" of the deposit layer, and soaking time will allow the cleaner to penetrate and soften the deposit layers. Systems with high atomization pressure will have no impact pressure on the IGVs, because the spray pressure will have decayed approx. 20 cm from the nozzle outlet, and the atomized droplets will need to be carried by the relatively low air flow rate produced at crank speed. Most high-pressure systems do not show the same effectiveness in removing salts and insoluble compounds on downstream stages. Typical location of wash nozzles for both on-line and off-line systems is shown in Figure 26.

Drainage: The effluent water collection system to drain and remove dirty water out of the engine is of prime importance. Equally important is the isolation scheme to prevent run-off water from penetrating sensitive areas such as sealing and cooling air systems, and instrumentation air systems. The physical location of bleed air taps on compressor casing is also important. If they are located on the bottom, they are likely to drain run-off water, and therefore, should preferably be located in the upper part of the casing. Drains in air inlet and compressor casing, combustion chamber, and exhaust should be located at the lowest point. The drain diameters should be sized for an easy run-off. Care must also be taken that they do not become plugged with dirt.
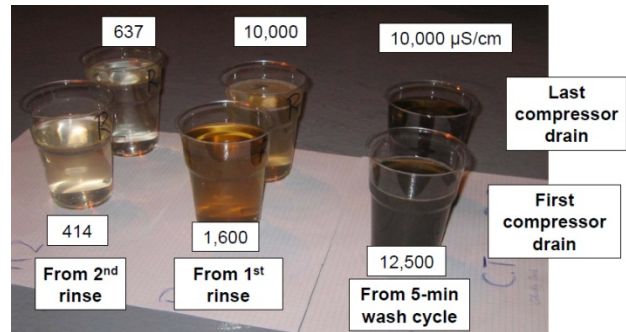

Figure 27: Effluent from Off Lne Water Washing: Visual Assessment and Conductivity Evaluation. (Courtesy Turbotect Ltd., Bromley & Stalder).

Engine Speed Variation: Off-line crank cleaning is very efficient for removing all deposits on all the compressor stages. To enable penetration of the wash and rinse fluid through the entire axial flow compressor, off-line washing should be conducted at *variable speeds*; for example, by injecting the solutions during coast down of the shaft, after an acceleration of up to 500 to 600 rpm. By doing this, the pattern of the centrifugal forces on the injected solution through the compressor will decrease and allow better wetting and distribution on the blade and vane surfaces of all stages. By contrast, off-line washing at high and constant cranking speed will result in a lower cleaning efficiency. Conductivity measurements and checks on the clarity/turbidity of the drain water will help assess cleaning efficiency.

Procedures and Precautions: The OEM's recommendations and checklists should be followed prior to a crank wash procedure. Some typical items of importance include, although they are very engine specific:

- Ensure that OEM's Wheel Space Temperature criteria are met prior to the crank wash.
- Seal and atomizing air pipes should be closed-off to avoid water entry.
- IGVs (if applicable) should be in the open position (maximum airflow) prior to the crank wash.
- All drains should be opened.
- Flame detector valves should be closed.
- Auxiliary air compressor should be disconnected.
- Special precautions may have to be taken for regenerators, if these exist.
- If possible, the plenum should be hand washed to avoid dirt being washed into the compressor.
- Follow the OEMs or Wash system supplier's recommendations regarding the duration and

amount of fluid injection. These guidelines may need to be modified by evaluating the results.

- Approved anti-icing agents will be required if off-line cleaning is performed at ambient temperatures below or near to freezing. Even at crank speed, some degree of temperature depression will occur at the bellmouth.

The rinse cycles need to be repeated until the effluent is clean (Figure 27).

On Line Washing

The basic objectives of on-line cleaning are to **maintain** the cleanliness of a compressor after off-line washing, to **maintain** power and efficiency by minimizing ongoing losses, and to **extend** the operating period between shut-downs required for off-line (crank) washing. On-line washing for fouling control has become increasingly important with base load combined cycle plants and CHP plants. It is also important for gas turbines in mechanical drive service, where little or no redundancy is installed and where the downtime associated with crank washing must be minimized.

On-line wet cleaning is performed while the gas turbine is in operation and at load. The procedure involves the injection of a mixture of water and chemical detergent via atomizing spray nozzles positioned around the compressor air intake plenum. This is followed by a flushing period using pure water. With on-line cleaning it is mandatory to use demineralized water for preparing the cleaning fluid and for flushing. This is because the turbine is in operation, and high temperature corrosion damage may occur if sodium or other contaminant metals enter the combustion path.

The water specification of the particular OEM should be followed, but typical values are presented below:

- Total Solids (dissolved and undissolved) ≤ 5 ppm
- Total alkali and other metals which may promote
- Hot corrosion (Na, K, Pb, V) ≤ 0.5 ppm
- pH 6.5-7.5

An on-line washing program should always be started on a clean engine, after an overhaul or crank wash. It is not recommended to perform on-line washing on a heavily fouled engine because large quantities of dirt removed from the front stages would instantaneously pass through the compressor. Therefore, after starting an on-line wash program, the time intervals between subsequent washings should be

kept short; approximately every three days to weekly, depending on the local conditions. Also, depending on the type of deposits (i. e., portion of water-insoluble compounds), detergent cleaners may be used for every on-line wash, or for every second or third on-line wash, but not less frequently than once per week. Note that the longer detergent washing is not done, the greater the risk of downstream contamination due to large portions of insoluble compounds suddenly being removed when the next detergent wash is performed. Thus, frequent on-line washing using detergents is advisable to minimize the accumulation of insoluble foulants.

The duration of each on-line wash can also be varied according to the degree of fouling, engine size, and plant experiences, etc. Typical on-line cleaning cycles are in the order of 10-20 minutes, and a flushing or rinsing cycle (using only demineralized water) of about the same duration should be applied after each cleaning cycle with detergent; for example, 10-20 minute cleaning cycle with detergent, followed by 10-20 minute flushing cycle without detergent. This type of regular on-line wash regime will extend the operating period between outages required for off-line cleaning, which is particularly important for base load plants.

The design of an on-line washing system should attempt to obtain the highest possible cleaning efficiency with the lowest injection mass flow rate, and this **can** be achieved in combination with an optimum washing regime as discussed above. Frequent on-line washing (to keep a clean compressor clean) enables the use of low injection mass flow rates, and this can only be considered as "good" for the gas turbine. To summarize:

- Frequent on-line cleaning with a low injection mass flow system minimizes the risk of deposits being suddenly washed from the front stages onto downstream compressor stages. This also addresses concerns that removed dirt may enter airfoil film cooling systems of turbine blades.
- Low injection mass flow reduces blade loading, and creates less stress on downstream blading.
- If the gas turbine uses flame detectors, high water mass flow may interfere with flame detector intensities, and may also create a trip by causing fogging of flame detector lenses, etc.
- Higher CO emission levels may be observed during on-line washing, which becomes more significant with higher water injection rates.
- Typically, high mass flow nozzles create

larger sized droplets. This means they are more influenced by gravity, and have a greater tendency to fall and be deflected onto inlet plenum surfaces. This also increases the risk of blade erosion.

- Effective on-line cleaning requires that the IGVs are thoroughly wetted with appropriately sized water droplets (typically 50-250 microns range). Any excess water is likely to "stream" over inlet plenum surfaces and struts, etc., and serves little or no purpose in the washing process. As mentioned above, excess water impacting the root area of IGVs may also initiate erosion of the rotating blades.

- Lower injection mass flow rates reduce demineralized water and cleaner consumption, and also reduce the size, volume and cost of the wash skids.

- Experience has shown that a low water wash mass flow does not impair on-line cleaning efficiency.

On-Line Compressor Cleaning Efficiency

Fouling of the first stage guide vanes is the primarily cause of reduced air mass flow through the compressor. On-line cleaning is most effective in removing such deposits, and therefore, restoring design air mass flow and lost power. Regular, on-line cleaning will keep inlet guide vanes clean and free from deposit build-up. Droplets of cleaning solution or water may survive up to the 6th stage in some gas turbines (depending on the stage loading of the compressor), but most will have vaporized by then. On-line cleaning has no effect on downstream stages, but there is some evidence that dirt from the front stages may deposit on rear stages.

Blade Wetting Considerations with On-line Washing: Effective wetting of the IGVs is obtained by a uniform and finely distributed atomized cleaning solution. Droplets must be stable in size and small enough that they do not cause blade erosion (due to the high blade speeds during operation). Droplets are subject to gravity, so they must also be light enough that they do not drop out of the air stream before they reach the compressor blade surface. Non-uniform wetting of the IGVs will result in spot cleaning and heavier droplets will most likely fall to the bottom, wasting some of the injected cleaning solution.

Optimum Washing Regime for Axial Flow Compressors An optimum-washing regime would combine on- and off-line cleaning to minimize power deterioration and extend the operating period between outages required for crank washing. Depending on local site conditions, the number of off-line washes may be reduced to two or three per year, compared to four or more per year without on-line cleaning. Information on some important field studies involving combined on-line and off-line wash programs is presented below.

CONCEPTS OF CONDITION MONITORING

Choice of Condition Monitoring Approaches

The choice of the condition monitoring philosophy (on-line vs. off-line), and the mix of the condition monitoring *technique(s)* are based on the following criteria (Meher-Homji, 1996):

1. What are the specific plant objectives in installing the condition monitoring system? What specifically do users hope to get from the system?
2. Where is the machine located? For example, offshore locations may have special requirements. Unmanned stations would also have special condition monitoring requirements.
3. What particular group of machines are under consideration? What are the key failure modes?
4. What is the criticality of the machinery being monitored?
5. What are the mission objectives (i. e., is it performance, reliability, readiness)?
6. What is the relevant plant operation maintenance philosophy and can the condition monitoring technique(s) be successfully implemented? *Implementation is a key issue.*

An appropriate *set* of condition monitoring technologies should be chosen based on failure modes, detailed engineering studies and an assessment of how valuable information is when difficult value judgments have to be made relating to machinery operation. For large critical gas turbines, it is usually a combination of technologies that have to be implemented to obtain good results.

Condition Monitoring Approaches

The concept of a slow degradation of component strength or performance is the basis for condition monitoring systems. The condition monitoring system relies on a variety of sensors that help in the observation of component degradation.

Aerothermal Performance Analysis

The aerothermal performance of turbomachinery provides invaluable insight into its operating health. Performance analysis can vary from relatively simple calculations to advanced gas path analysis techniques used to pinpoint faults. It involves computation and correlation of all performance variables in the gas path. An aerothermal performance analysis system should be capable of modeling and detecting degraded performance.

It is often valuable to integrate such a system with vibration analysis as several vibration problems are manifestations of underlying aerothermal problems. Further, this technology provides insight into how efficiently fuel is being utilized and thus facilitates significant fuel savings if degradation is controlled. Included within "performance analysis" are items such as power turbine inlet temperature or exhaust gas temperature spread monitoring which is a critical and valuable indicator of hot section health. Actions such as this can significantly extend hot section life. Excessive spreads can occur due to a variety of reasons including excessive air leakages, blockage of nozzles and cracks in the combustor liner/ transitions.

Vibration Analysis

With the correct choice of sensors and analysis techniques, vibration analysis is an excellent condition monitoring tool when used in conjunction with other condition monitoring techniques.

Transient Analysis

Condition monitoring based on transient data relating to both performance and vibration is an important facet of any analysis system. An overview of transient analysis techniques is made by Meher-Homji and Bhargava (1992). In a gas turbine, valuable condition monitoring information is available by examining the profile of startup acceleration, coast down times, EGT response during light off and other transient behavior.

Mechanical Transient Analysis

Compared to aerothermal transient analysis, mechanical transient analysis has been an area that has been used extensively in condition monitoring systems over the years. Transient techniques include:

- Vibration Cascade Analysis: These permit a visual representation of the frequency content of vibration signal during startup or shutdown as shown in Figure 11. Techniques are available to check rotor related and fixed frequency amplitudes during transient conditions. Vibration cascades can be formed either on a Delta time or Delta RPM basis.
- The Bode and Nyquist plots are classic rotor dynamic displays of particular use for displaying the location of critical speeds and their amplification factor. The separation margin from the critical speed to the operating speed range can be reviewed for compliance with manufacturers or industry recommendations.
- Another useful representation for transient analysis may be based on a vectorial summation technique of proximity probe gap voltages. This can be used in a display to depict the movement of the shaft within the bearing during startup/shutdown.
- For startup analysis of other mechanical parameters (lube oil temperatures, and pressure), it is possible to prepare maps showing these parameters as a function of rotor RPM & load as appropriate.

Problems which can be detected by Mechanical Transient Analysis include:

- Bearing Wear and damage can be detected by evaluating the transient data for changes in amplification factor (Q factor).
- Thermal Bows occurring in the rotor. Very often, this is the result of a hot restart when the rotor has taken on a bow and the casing has cooled non uniformly.
- Rotor Rubs can be detected by analysis of vibration signatures

Dynamic Pressure Analysis

The use of dynamic pressure transducers has worked well to detect certain blading instabilities and compressor instability. This is an important facet of condition monitoring that has not received much attention.

When applied to the combustors, the dynamic pressure signatures can provide information regarding combustion instabilities, and subsequent combustor liner wear. With the use of dry low emission combustors, dynamic pressure measurement is a very valuable condition monitoring tool to ensure operability.

Lube Oil Debris Analysis

Debris is generated by rolling and sliding surfaces that are subject to normal, accelerated and incipient failure. This debris can be generated at differing production rates, and be of different materials size and distribution. Depending on failure mode, debris production can increase in certain size ranges. In rolling element bearings (such as used in aero derivative gas turbines) under full elastohydrodynamic lubrication (EHL) conditions, where film thickness is large compared to average bearing surface roughness, the predominant failure mode is spalling or macro pitting induced by surface fatigue. Particles produced are typically in the 100 - 1000μ range. In the boundary lubricated and mixed mode (partial EHL) regimes, particles are typically smaller (< 100μ). Under these lubrication conditions, abrasive and adhesive type accelerated wear models occur. Bearing skidding can occur when bearing loads are light and can produce small debris (< 25μ).

Borescope Inspection

One off-line Condition Monitoring technique that is successful and very necessary is borescope inspection. This is usually carried out at fixed intervals dependent on the machine and a video camera is used to record results. Borescope inspections are usually very quick and result in a minimum loss of turbine availability. For borescope inspections, it is important to have well trained personnel and clear cut procedures defined in concurrence with the machinery manufacturer, to ensure full coverage of the critical components[2]. By using a video camera to record the inspection, one can enlist expert outside help to interpret the data. Eddy current checking is also being done to detect cracks.

Condition Monitoring as a System

The previous sections outline specific methods, technologies, and processes that can be done manually and ad hoc. However, there is a trend towards automating condition monitoring and remote condition monitoring, especially in the context of fleet management. Remote monitoring and diagnostics, in conjunction with centralized data storage creates the ability to perform comparative analysis to similar engines (Fleet Statistics). Monitoring ancillary system performance identifies risk factors to engine durability (filter fouling rates, lube oil temperature and pressure control, fuel temperature, machine event diagnostics, etc.). Rigorous tracking of availability and reliability as key performance indicators and downtime analysis enables understanding and analysis of what systems and situations are having the most negative impact on these metrics.

Finally, it must be emphasized that a key requirement for successful condition monitoring is that all measures have to be performed regularly and there is sufficient expertise available and accountable to analyze and act on the input as it is received.

CONCLUSIONS

The operation and maintenance of gas turbines requires an understanding of the working principles of the gas turbine and its components. Additionally, fuel, as well as air filtration,has an important impact on the operating characteristics, and the life of the gas turbine. The results of all measures can be evaluated by a thorough condition monitoring regimen. This tutorial is intended to further the understanding in these areas.

---

2 Borescope inspection can show up component cracks, erosion, corrosion and buckling.

REFERENCES

Bagshaw, K. W., 1974, "Maintaining Cleanliness in Axial Flow Compressors", *1st Gas Turbine Operations and Maintenance Symposium*, National Research Council - Canada, October, 1974.

Brekke, O., Bakken, L. E., 2010, Performance Deterioration of Intake Air Filters for Gas Turbines in Offshore Installations, ASME GT2010-22454.

Bromley, A. F., 1986, "Gas Turbine Fuel Treatment - The Reasons Why," Diesel and Gas Turbine Worldwide, June 1986.

Bromley, A. F., 2006, "Gas Turbine Fuels and Fuel Treatment," Combined Cycle Journal, Outage Handbook, 3Q 2006, pp. OH33-OH39.

Elliott, F. G., Kurz, R., Etheridge, C., and O'Connell, J. P., 2002, "Fuel System Suitability Considerations for Industrial Gas Turbines', ASME GT2002-30592.

Felix, P. C., 1977, "Corrosion and its Prevention in Modern Stationary Gas Turbines," Brown Boveri Review, 1-77, pp. 4—46.

Felix, P. C., 1979, "Practical Experience with Crude and Heavy Oil in Stationary Gas Turbines," Brown Boveri Review, 2-79, pp. 89-96.

Felix, P. C., and Strittmatter, W., 1979, "Analysis of Air Pollution on the Erection Site of a Brown Boveri Gas Turbine," *Brown Boveri Review*, Vol. 66, February 1979, pp 97-103.

Glassman, I., 1996, *Combustion*, Academic Press, New York, 3rd Edition.

Johnson, K. W., 1996, "Operation of Combustion Turbines on Alternate Fuels," Proceedings of ASME IGTI Turbo Expo, Birmingham, UK, June 10-13, 1996, ASME Paper No. 96-GT-7.

Kurz, R., Wen, C., Cowell, L. H., Lee, J. C. Y., 2006, 'Gas Fuel Flexibility Considerations for Low Emissions Industrial Gas turbines', The Future of Gas Turbine Technology, 3rd International Conference 11-12 October 2006, Brussels, Belgium.

Kurz,. R., Brun, K., 2012, Fouling Mechanisms in Axial Compressors, TransASME JEGTP, Vol. 134, GTP-11-1153.

Lay, K. W., 1974, "Ash in Gas Turbines Burning Magnesium-Treated Residual Fuel," Transactions of ASME Journal of Engineering for Power, April 1974, pp. 134-137.

Lefebvre,A. H., 1998, *Gas Turbine Combustion*, 2nd Ed., Taylor and Francis, Philadelphia.

Lieuwen,T., McDonell,V.,Petersen, E., Santavicca,D., 2006," Fuel Flexibility Influences on Premixed Combustor Blowout, Flashback, Autoignition, and Stability", ASME paper GT2006-90770.

Meher-Homji, C. B. and Bhargava, R. K., 1992*, "Condition Monitoring & Diagnostic Aspects of Gas Turbine Transient Response,"* ASME Paper No. : 92-GT-100, 1992 ASME Gas Turbine Congress, Cologne, June 1-4, 1992. Also in International Journal of Turbo & Jet Engines, Vol. 11, No 1, 1994.

Meher-Homji, C. B., 1996, *"Condition Monitoring of Power Plants,"* Handbook of Condition Monitoring and Maintenance Management in Industry, Elsevier Publishing, 1996.

Meher-Homji, C. B., and Gabriles, G., 1998, *"Gas Turbine Blade Failures- Causes, Avoidance, and Troubleshooting,"* Proceedings of the 27th Turbomachinery Symposium, Turbomachinery Laboratories, Texas A&M University, Houston, Texas, September 22-24, 1998.

Meher-Homji, C. B., 2000, *"The Historical Evolution of Turbomachinery,"* Proceedings of the 29th Turbomachinery Symposium, Houston, Texas, September 2000.

Meher-Homji, C. B., and Bromley A. F., 2004 *"Gas Turbine Axial Compressor Fouling and Washing,"* Proceedings of the 33rd Turbomachinery Symposium, September 2003, Houston, Texas.

Meher-Homji, C. B., Chaker, M., Bromley, A. F., 2009, "The Fouling of Axial Flow Compressors- Causes, Effects, Susceptibility and Sensitivity," Proceedings of the ASME International Gas Turbine Congress, Turboexpo 2009, Orlando Florida, June 8-012, 2009. ASME Paper No: GT2009-59239.

Meher-Homji, C. B., and Bromley A. F., *"Gas Turbine Fuels- System Design, Combustion and Operability,"* Proceedings of the 39th Turbomachinery Symposium, George R. Brown Convention Center, Houston, Texas 4-7 October, 2010.

Moliere, M., Gazonnet, J. P., and Perin, S., 1995, "Updated EGT Experience with Ash-Forming Fuels: A Step Ahead," National Conference of Gas Turbine Generator Users, Hainan, P. R. China, Nov 27 to Dec 3, 1995.

Moliere, M., Huber, P., Stalder, J. P.,and Bromley, A. F., 2002, "Key Considerations When Embarking on a Heavy Fuel Project," Proceedings of Power-Gen Asia, Singapore, October 2-4, 2002.

Stalder, J. P., and van Oosten, P., 1994, "Compressor Washing Maintains Plant Performance and Reduces Cost of Energy Production," *ASME International Gas Turbine and Aeroengine Congress*, The Hague, Netherlands, June 13-16, 2001, ASME Paper No: 1994-GT-436.

Stalder, J. P., 1998, "Gas Turbine Compressor Washing State-of-the-Art Field Experiences," *ASME International Gas Turbine and Aeroengine Congress*, Stockholm Sweden, June 2-5, 2001, ASME Paper No: 1998-GT-420.

Stalder, J. P., and Huber, P. A., 2000, "Use of Chromium Containing Fuel Additives to Reduce High Temperature Corrosion of Hot Section Parts", ASME International Gas Turbine & Aeroengine Congress, Munich, Germany, May 8-11, 2000, ASME Paper No. 2000-GT-138.

Stringer, J., 1977, "Hot Corrosion of High Temperature Alloys", Annual Revue Material Sciences, vol. 7, 1977, pp. 477-509.

Zubler, R. and Stalder, J. P., 1998, "Review of Gas Turbine Fuel Treatment," Chinese Association for Gas Turbine Power Generation Users Conference, Shenzhen, P. R. China, June 1998.