GE Power Generation

Considerations When Burning Ash-Bearing Fuels in Heavy-Duty Gas Turbines

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CONSIDERATIONS WHEN BURNING ASH-BEARING FUELS IN HEAVY-DUTY GAS TURBINES

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INTRODUCTION

GE is the world's leading manufacturer of gas turbines utilizing ash-bearing fuel oil. GE machines have accumulated more operating hours than those of any other manufacturer. This paper highlights GE's experience with burning crude, residual, and other ash-bearing fuels in the various GE gas turbine product lines. The paper also presents discussion regarding the combustion system design; hot section design and materials; fuel treatment and handling; and turbine accessory systems. In addition, this paper goes into depth on laboratory testing of hardware and ash deposit mechanisms, effects of increased firing temperature, the relative merits of various fuel additives currently used, and inspection intervals.

HEAVY FUELS OPERATING EXPERIENCE

Introduction

GE's experience burning heavy ash-bearing fuels dates to the infancy of the gas turbine business in the 1940s and 1950s. More than 300 GE-designed machines have accumulated in excess of 7.8 million fired hours using crudes, residuals, or blends of crudes and distillates as the primary fuel.

A large number of machines were installed in the decade 1950 to 1960. Interest then waned through the 1960s as low cost natural gas became more plentiful, and the gas turbine market began to shift to electric utility peaking applications where gas or distillate were the preferred fuels. In the late 1960s when natural gas reserves began to decline, heavy fuel applications again increased. Many machines were sold with dual fuel capability, using ash-bearing types as secondary fuels, or provisions were required for possible conversion to heavy fuel. This interest lapsed again after a few years as natural gas once more became plentiful. Only very recently has interest in heavy fuel, particularly in the Far East, become a factor once again.

Table 1 shows GE's overall heavy fuel experience. Early operating experience provided the technological base that made possible the success of the large number of more sophisticated heavy-fuel-fired machines installed in more recent history.

GE experience burning heavy ash-bearing fuels at various firing temperatures is shown in Figure 1.

Initial Experience — 1950 Through 1960

Early use of ash-bearing fuels in the 1950s and 1960s was in units ranging from 5,000 kW to 15,000 kW, with firing temperatures around 1450F (788C), which were typical of that stage of gas turbine development. Installations included electric utilities, oil pipelines, railroad locomotives, and ship propulsion, and nearly three million operating hours were accumulated. Many of these units remain in service today, although several have been converted to natural gas fuel. The first "test-beds" where fuel washing and treatment systems were developed were residual oil burning machines operating with Central Vermont and Bangor Hydroelectric utilities. The fuels were heavy residuals with gravities ranging from 0.90 to 1.0, vanadium from 50 to 360 ppm, and sodium from 20 to 100 ppm before washing. Successful operation was demonstrated at a nominal firing temperature of 1500F (816C), with more than 19,000 hours on the longest running unit.

The most heavy-fuel operating hours (1.9 million) were achieved on 57 Union Pacific Railroad locomotives. The residual fuel contained less than 5 ppm sodium, and vanadium levels averaged about 10 ppm, requiring a magnesium additive. Each unit accumulated some 35,000 fired hours at 1450F (788C) firing temperature.

Nine machines in crude oil pipeline service in Saudi Arabia logged a further total of 700,000 hours on crude which did not require desalting since the sodium levels were below the specified limit of 5 ppm. However, a magnesium additive was injected to inhibit the 12 ppm vanadium. The units were remotely operated and started and shut down on crude fuel. Finally, the GTS John Sargent, a Liberty ship converted to gas turbine

Table 1
GE-DESIGNED GAS TURBINE WORLDWIDE EXPERIENCE (AS OF FEBRUARY 1994)
WITH HEAVY ASH-BEARING FUELS

Experience Period	Site Location	Experience Period	No. of Units	Fired Hours
1950-1960	All	1950-1960	78	2,700,000
1961-1993	Africa	Crude	10	577,400
		Residual	14	305,000
		Blend		
		Total	24	882,400
	Asia	Crude	21	271,070
		Residual	21	322,935
		Blend	6	70,000
		Total	48	664,005
	Europe	Crude		
		Residual	6	45,000
		Blend	18	1,158,100
		Total	24	1,203,100
	Middle East	Crude	88	1,907,631
		Residual	3	15,000
		Blend	6	101,000
		Total	97	2,023,631
	N. America	Crude	8	15,600
		Residual	10	106,300
		Blend	2	47,500
		Total	20	169,400
	S. America	Crude	2	22,000
		Residual	14	85,000
		Blend	1	17,000
		Total	17	124,000
	Period Total	Crude	135	2,838,701
		Residual	80	1,992,335
		Blend	15	235,500
		Total	230	5,066,536
	Grand Total	Various	308	≈7,800,000

GT24235A

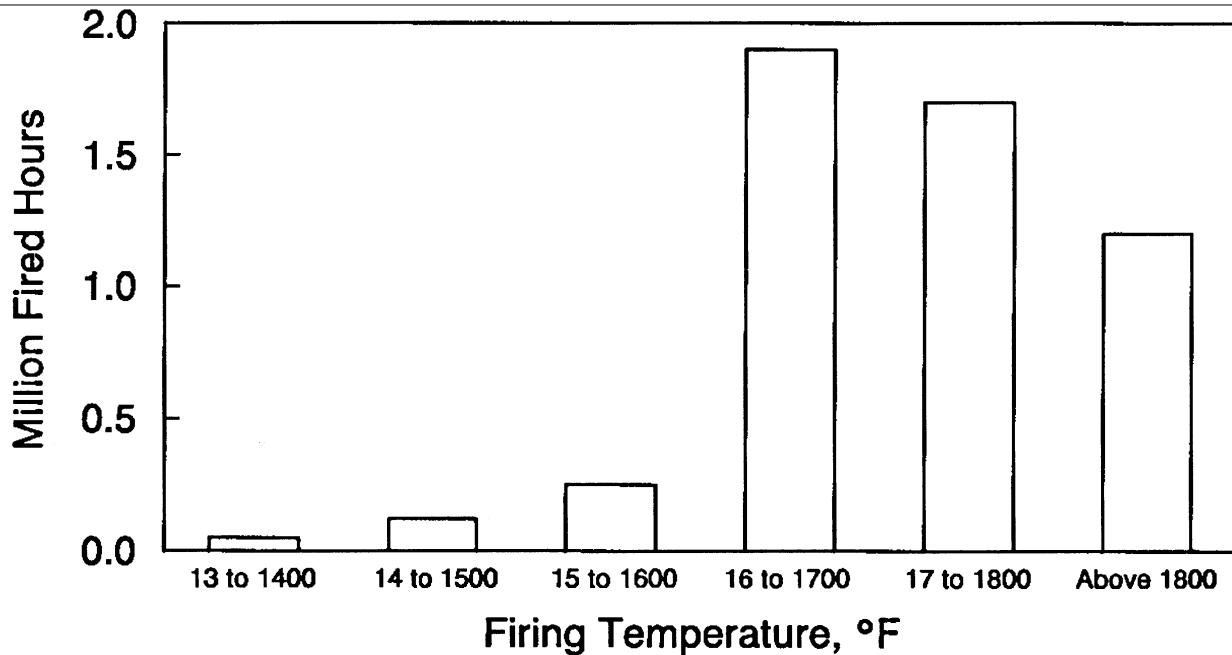**Figure 1. Firing temperature operating experience**

drive, logged 10,000 hours of service, nearly 8,000 of which were achieved on a variety of residual oils which were desalted and treated on board. During this period of operation the hot gas path was completely free of corrosion.

Continuing Experience — Late 1960s On

In the decade of the late 1960s to the late 1970s, over 150 GE machines were installed with heavy fuel capability. The majority of these were used for power generation, both utility and industrial, with others operating as mechanical drive machines and for ship propulsion. Within this time frame, more than one million hours were accumulated, and several units achieved in excess of 30,000 hours each. Unit ratings ranged from 10 MW to 65 MW, with firing temperatures of 1450F to 1850F (788 - 1010C).

Nine Frame 5 machines in Indonesia (Caltex), were used for power generation to pump crude oil. The fuel was a waxy crude with low vanadium (0.5 ppm) that was water washed to reduce sodium concentration from 10 ppm to less than 1 ppm. The units were baseloaded at a firing temperature of 1650F (898C). Although no current operating data is available, the machines had accumulated well over 200,000 hours in 1984, with more than 50,000 hours on some individual units. Hot gas path inspections were performed every 10,000 hours, major inspections every 20,000 hours, and the U700 turbine buckets provided excellent service to beyond 28,000 hours. Ten machines in France (Rhone-Poulenc), have logged well over one half million hours of service at firing temperatures of 1650F (898C). The units' high-viscosity fuel requires heating to 140F (60C), and air atomization for combustion. Some individual units have delivered in excess of 50,000 hours of service.

Additional machines in North Africa and Italy have also run at 1650F (898C) firing temperature on residual fuel containing high levels of vanadium and sodium before washing. Electrostatic precipitators provided desalting, and the fuel was inhibited with an organic oil-soluble magnesium additive.

A comprehensive test program was run on a Frame 5 unit at the GE facility in Lynn, Massachusetts to demonstrate the capability of burning oils at high firing temperatures. Both electrostatic and centrifugal desalting systems were installed for evaluation, and the unit has run on a variety of residual fuels up to firing tempera-

tures of 1850F (1010C). No corrosion on uncoated turbine buckets has been experienced. Three types of magnesium additives, water soluble, oil soluble, and suspendible solids, were evaluated, and it was shown that magnesium oxide slurries can be added to heavy fuels without any adverse effects on fuel pumps and flow dividers.

In addition to the numerous Frame 5 machines, many larger Frame 7 units were also installed in this time period using heavy oil as the primary fuel.

Ten units (MS7001B) were operated by Florida Power Corp. at its Bartow and DeBarry stations. At Bartow, the fuel was a high wax Libyan crude which was electrostatically desalted and inhibited with an oil soluble magnesium additive; it was also heated to 100/110F (38/43C) to avoid fuel filter plugging. These machines operated successfully at 1840F (1004C) firing temperature in peak load mode between 1972 and 1976, when the crude fuel became unavailable. Turbine washing to remove combustion ash deposits was performed every three months. Residual oil with up to 33 ppm sodium and 40 ppm vanadium was used at DeBarry and washed to reduce sodium to less than 1.0 ppm by a three stage electrostatic desalter; vanadium was inhibited by an oil soluble magnesium additive.

Another example of Frame 7 experience is the Alcoa Aluminum Bauxite plant in Paramaribo, Surinam. The unit went operational in 1976 using Trinidadian residual oil. The raw fuel had sodium levels from 80 to 125 ppm and vanadium varying from 65 to 85 ppm. Fuel treatment is achieved with a De Laval centrifugal washing system and injection of oil and water soluble magnesium in the ratio of three magnesium to one vanadium. Initial operation indicated some minor problems with the fuel pump, flow divider and fuel nozzle plugging when using water-soluble additive. A stainless steel screw-type positive displacement fuel pump and the addition of corrosion resistant materials to the flow divider eliminated two of the problems. Fuel nozzle plugging was eliminated by more thorough mixing of the magnesium and fuel with a centrifugal pump which allows the use of the less expensive water-soluble additive; oil-soluble additive is retained as a backup.

Unit operation through July 1987 occurred at a firing temperature of 1750F (954C), and 25,000 hours were accumulated. Since a major overhaul in 1987, the unit had been exercised monthly until November 1992, when it was placed back into continuous service at reduced load.

Inspection results indicated little to no corrosion problems on the turbine nozzles or buckets, and nozzle corrosion life (FSX-414 material) far in excess of 25,000 hours.

Saudi Arabian Experience

Most recent operating experience with heavy ash-bearing fuels (in excess of two million hours) has occurred on numerous GE-designed machines in Saudi Arabia. Riyadh Power Plant #7 (PP7) is an outstanding example, where sixteen Frame 7E machines have run continuously on crude at a firing temperature of 1740F (949C) for the past fourteen years. The fuel, light Arabian crude, is supplied directly from the Riyadh refinery and has 10 to 30 ppm vanadium; it is washed on site and a magnesium additive is introduced in the ratio of 3:1 Mg:Va. Turbine base heating is normal, and the units start and stop on the crude fuel. After more than one million hours at PP7, there have been no significant problems in the hot gas path. Most of the units still have their original turbine buckets. Turbine water washing is performed on each unit at monthly intervals. Currently at PP7, GE is installing 4 additional Frame 7EA machines. These machines utilize the same crude oil as the existing 16 units. These units have a firing temperature of 2000F (1093C) and are expected to have a water wash interval of approximately 1000 hours.

In addition to PP7, there are twenty-eight other GE-designed machines operating in the Kingdom either on similar crude or blends of distillate and crude. These units include Frame 5s, 6s and 7s installed in Saudi Consolidated Electric Company's (SCECO) Central, Western, Southern and Eastern regions at sites such as Jeddah, Tihama and Quaisumah. They have accumulated more than one million operating hours.

GE-designed machines in Saudi Arabia have operated satisfactorily on various crudes and crude/distillate blends for over two million hours. Since the majority of the machines are used in baseload or mid-range applications, operating hours continue to accumulate rapidly.

Competitive Experience

Heavy duty machines installed by our three major competitors have about half the total operating hours of GE units using heavy ash-bearing fuels. Most current experience has been in Saudi Arabia, where several competitor units operate side-by-side with GE machines and use the same fuel. It appears that in the Central, Western and Southern regions of SCECO, turbine bucket failures due to corrosion have been common on competitors machines using light Arabian crude and blends of crude/distillate. The problems seem to occur on the first and second turbine stages after relatively few hours (10 - 15,000), and many machines have had both stages replaced at least once in the past ten years. In addition, output degradations of as much as 30% have been reported.

A further comparison can be made with units situated in Taiwan, where GE Frame 7Es and competitor units operate at the same site and on the same no. 6 residual fuel. Again, the competitor units have suffered turbine bucket corrosion requiring premature bucket replacement, while the GE units have been free of these problems. Overall, the GE machines have been utilized almost twice as much as the other manufacturers' equipment, with each GE unit accumulating approximately 1,600 hours per year as opposed to about 900 hours on the competitors' units.

Significance of Field Experience

Extensive field operating experience accumulated on GE gas turbines burning heavy oils provides a time-tested evaluation of the ability of these machines to operate economically and reliably over extended periods. Early experience of units operating at lower firing temperatures is highly relevant to the heavy fuel operation of today's gas turbines with higher firing temperatures. The extensive heavy-fuel technology developed during this early period includes:
- Determination of effects of trace metal contaminants (vanadium, sodium and potassium) on high temperature materials employed in the turbine.
- Development of appropriate fuel treatment systems to remove or inhibit the corrosive trace metal contaminants.
- Determination of the relationship of fuel quality and trace metal contamination limits to reliable operation.
- Evaluation of ash deposit rates, including methods of cleaning and their effect on performance.
- Development and design of combustion systems and fuel handling and control systems.

This technology base has now been extended to the higher temperature MS7001EA and MS9001E machines. The total GE experience on ash-bearing fuels is unparalleled in the industry.

TURBINE GAS PATH DESIGN

Introduction

GE gas turbine designs are based on both a firm analytical foundation and field experience. Evolution of proven designs has resulted from improved components and materials which have been prudently applied to increase power and thermal efficiency. While designs are carefully tested in development facilities, field performance continues to provide the best proof of design effectiveness.

Turbine Gas Path

Increasing firing temperature has been a major developmental thrust for turbines over the past 30 years, since increased firing temperatures increase the output and efficiency. Higher turbine firing temperatures are achieved by improved nozzle and bucket materials and by air cooling. Concurrent developments in alloy corrosion resistance and bucket surface protection systems have provided fuel-flexible, corrosion-resistant components. Base load firing temperatures have increased approximately 25F (14C) per year, from 1500F (816C) in 1961 to 2000F (1093C) today. This corresponds to an annual increase in attainable output of approximately three percent and an annual increase in efficiency of approximately one percent. Thus, machine development finds significant rewards in reduced first-cost per unit output and reduced costs of operation.

GE turbines use high-energy stages with low reaction. The most important advantage of this design is the higher firing temperatures achievable at constant first-stage bucket metal temperature, as illustrated by Figure 2. This design approach also minimizes the required number of turbine stages, providing fewer operating components, less exposure to corrosion, less maintenance and, consequently, lower overhaul costs. To enhance the capability to burn heavy fuels, other features are also included, such as thick wall sections, thick trailing edges, and wide throats.

Since the early 1960s, air extracted from the compressor has been used to cool the nozzles and buckets. Nozzle metal temperatures were maintained at about 1550F (843C) as firing temperatures were raised. By the late 1960s, turbine base load firing temperatures were approximately 1700F (927C). Significant firing temperature increases depended on first-stage bucket cooling and deposit washability.
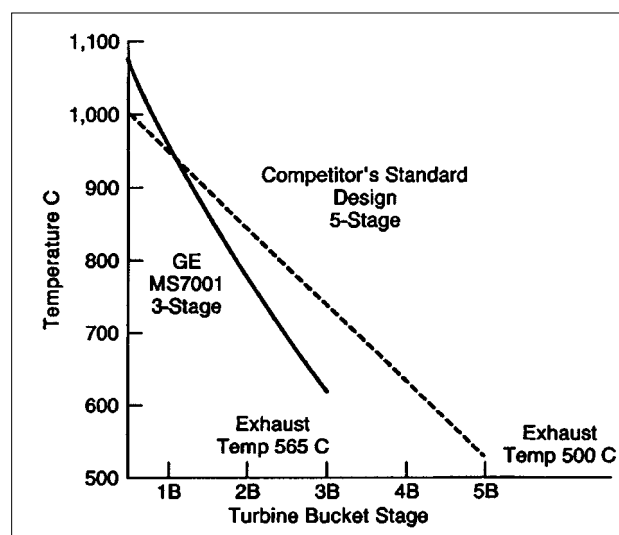
Figure 2. Bucket metal temperature

The cooling air circuit of the first-stage nozzle for the crude oil burning MS7001EA or MS9001E starts with air impinging on the nozzle internal cavity surface. The air is then exhausted into the gas path through trailing-edge rectangular slots and through large pressure-side film holes which are not subject to plugging by ash deposits.

Bucket air cooling circuits are entirely internal to the rotor, starting with a radially inward extraction from the inner diameter of the compressor gas path. Since the compressor acts as a natural centrifuge, this extraction point prevents foreign matter from entering the cooling circuits and plugging the bucket cooling passages. The internal circuit also eliminates the need for seals or packings between the rotor and stator to contain the cooling air. Metering of the air is accomplished by the buckets, because the cooling circuit has a much greater flow area than the bucket cooling holes. This feature provides high velocity for efficient heat transfer in the bucket. Another advantage of this design is that cooling air exits from radial holes at the bucket tip, permitting burning of ash-bearing fuels without plugging of the bucket cooling system.

Cooled buckets and advanced air-cooled first-stage nozzles were incorporated in MS7001B turbines in 1972. A base load firing temperature of 1840F (1004C) was established. The success of this development has resulted in satisfactory operation in over 230 MS7001B units.

In the more recent MS7001EA and MS9001E, the nozzle and bucket cooling have been further improved to provide base load firing temperatures in the 2000F (1093C) range. The second-stage
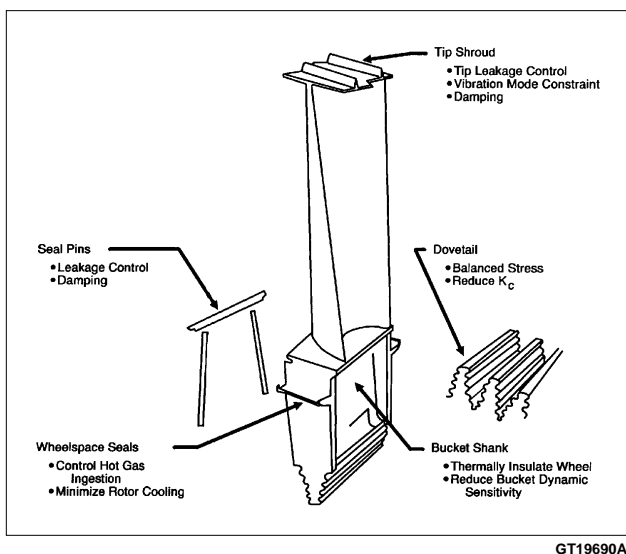
nozzles and buckets are also internally cooled, similar to the first stage.

Buckets are subjected to gas forces which can cause bucket vibration. Resonance between forces and bucket natural vibration modes are avoided at full operating speed. However, resonance cannot be avoided during startup and shutdown. All GE-designed turbines incorporate features to suppress resonant vibration. These include the long-shank bucket with a friction type connection at the bucket platform and a tip shroud (Figure 3).

In the long-shank bucket design, damping is introduced near the midspan by placing axial pins underneath the platform between adjacent buckets. In the first stage, the damping provided by these pins virtually eliminates all vibration involving tangential motion and controls vibration in the other modes. The shank also provides thermal isolation between the gas path and the turbine wheel dovetail. Since the shank is a uniform unrestrained section, stress concentrations in the dovetail are minimized.

The integral tip shroud is the second major vibration control feature. These are used on the long second and third stages. The individual bucket shrouds are interlocked to form a continuous band during operation. The natural tendency for the buckets to untwist under centrifugal load is used to force the mating faces of adjacent shrouds together, providing friction damping. The tip restraint provided by the continuous shroud band eliminates the first flexural mode of vibration, which is the most sensitive.

Turbine deposits from heavy fuels cause random aerodynamic vibration stimuli in the gas path. The vibration-resistant design has enabled GE gas turbines to operate reliably while subjected to these stimuli.

Several test techniques are used to assure adequate vibration margin. Stationary bench testing is used to drive a bucket through a range of frequencies to identify its natural modes. Wheelbox testing is performed in a large, evacuated chamber in which full turbine stages are run throughout the operating speed range to determine bucket vibration response. Gas force excitation is generated by an array of nozzles which direct high velocity air at the buckets. Vibration data from strain gauges mounted on the buckets is fed through slip rings into a processing facility, where both tape recording and on-line analyses are possible. Thorough testing, combined with extensive service experience, provides a sound design basis. Since 1958, when these concepts were introduced, no bucket of this design has experienced a vibration failure in the shank or dovetail.

Combustion Design

All modern GE heavy-duty gas turbines use multiple reverse-flow combustors similar to that illustrated in Figure 4. Each combustor is composed of a liner, transition piece, and fuel nozzle, chosen for its fuel flexibility, maintainability, and ease of testing at full pressure, temperature, and flow conditions in the laboratory. The design objectives for a combustor are listed in Table 2.

Air atomizing fuel nozzles (Figure 5) are utilized for liquid fuel applications. Air pressure atomizes the fuel to assure complete combustion and a smoke-free stack over the operating range of the gas turbine.

Figure 4 shows that compressor discharge air flows around the transition pieces while cooling them. It enters the combustion liner through various air passages in the liner. Fuel injected into the

Figure 3. MS7001 gas turbine construction features of second- and third-stage precision cast buckets
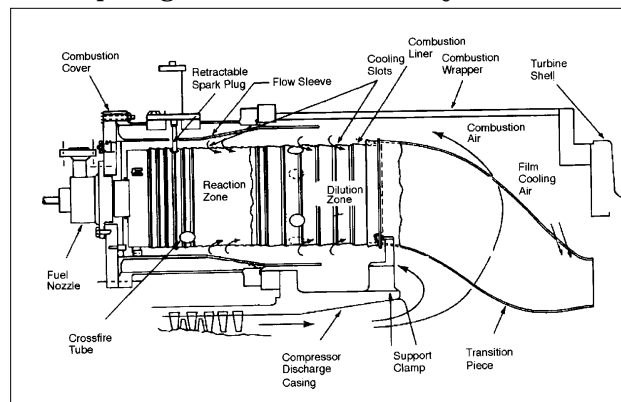
Figure 4. Multiple reverse-flow combustor

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Table 2
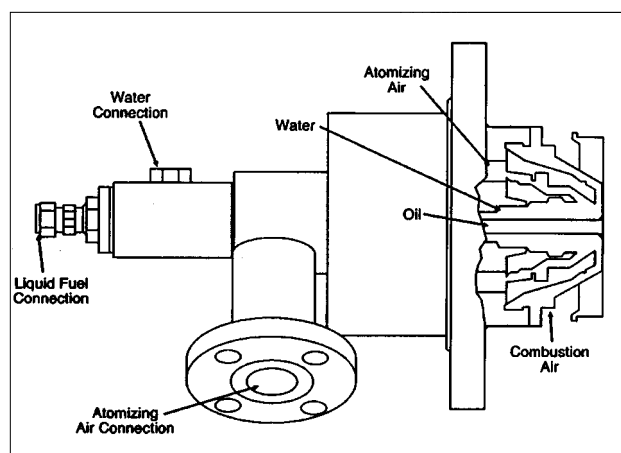**COMBUSTION DESIGN OBJECTIVES**

Design Parameter	Fuel Property
Metal Temperatures	Residual Carbon Carbon/Hydrogen Ratio Aromatic Content
Smoke	Residual Carbon Hydrogen Content Aromatic Content
Ignition Reliability	Viscosity Heating Value Volatility Flammability Limits
Cross-Firing Reliability	Flammability Limits Heating Value
Atomizing Air Requirements	Viscosity Surface Tension Density
Combustion Efficiency	Carbon/Hydrogen Ratio Aromatic Content Flammability Limit
Emissions	Carbon/Hydrogen Ratio Fuel Bound Nitrogen Heating Value Water Vapor
Carbon Buildup	Carbon/Hydrogen Ratio Aromatic Content Viscosity

GT24242

Figure 5. Air atomizing fuel nozzle

mixing, which is achieved by air jet penetration from the walls of the combustor, becomes more difficult as the liner diameter increases. Consequently, full-size combustor testing at full flow and pressure is necessary to assure the adequacy of new designs. Additionally, the ability to economically perform extensive full-scale laboratory testing is a major advantage of the multiple-combustor approach. Almost all of the development work can be done on a single-burner test stand at full operating conditions.

The combustor ignition system includes spark plugs, crossfire tubes, and flame detectors. For reliability, two spark plugs and two flame detectors are used. Ignition in one of the chambers produces a pressure rise which forces hot gases through the crossfire tubes, thereby propagating rapid ignition to all other chambers. Flame detectors, located diametrically opposite the spark plugs, signal the control system when the ignition process has been completed. Because of the simplicity and reliability of this technique, it is used in all GE-designed heavy-duty gas turbines.
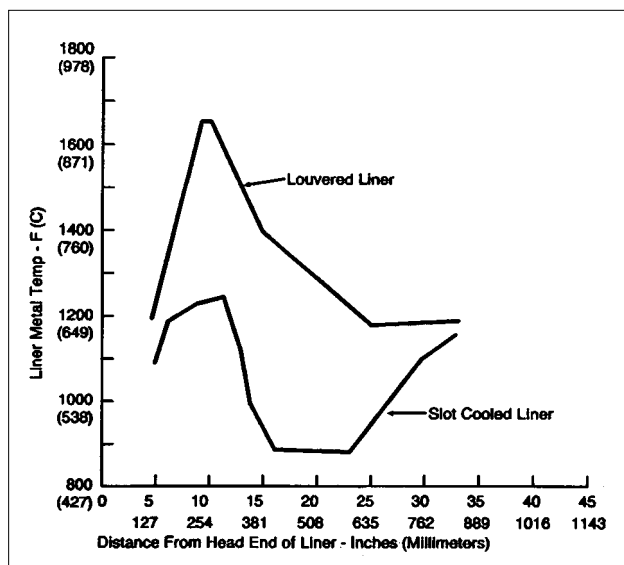
Combustion Liner

The combustion system has evolved from the original application of heavy-duty machines burning residual oil. Engineering development work on this system has continued, and the slot-cooled liner (Figure 6) is standard in the MS7001EA and MS9001E gas turbines.

The slot-cooled liner, originally developed by GE for aircraft gas turbines, has been modified for application to the heavy-duty gas turbine. It provides more uniform, more effective cooling than possible with a louvered liner. The slot-cooled liner operates with 250F (139C) lower metal tem-

combustion reaction zone burns with a portion of the available air entering the head end of the combustor. Recirculating flow patterns of air and burning gases provide flame stability. The hot combustion gases are then mixed with secondary air entering through downstream holes to dilute the gas and lower its temperature before it enters the turbine. The temperature profile of hot gases entering the turbine section is controlled to maximize the life of the turbine parts.

Heat transfers from the flame and hot gases to the liner walls and is removed by air sweeping over the inside and outside of the liner. The flow sleeves enhance liner cooling by increasing the cooling air velocity near the liner.

These combustors can burn a wide variety of fuels ranging from natural gas to the various process gases, and from naphtha to heavy residual oils. Dual fuel nozzles are often used to allow transfer between fuels without shutdown.

Neither mathematical nor geometric modeling has been adequate for combustion development because a scale model does not reproduce the chemical reactions, heat release rates, and aerodynamic mixing of the full-size design. Aerodynamic

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Figure 6. Slot-cooled liner, cutaway view

Figure 7. Liner cooling profiles

peratures than an equivalent louver system (Figure 7). It also operates with lower temperature gradients, which increases the comparative life of the parts. The slot-cooled liner is superior to the louver type for the more radiant flames from heavy fuels, and it eliminates the corner stress concentration points of louvers.

Another important innovation in liner design has been decrease in length. This "short" liner provides increased stiffness as well as reducing the amount of cooling air required, since the surface area to be cooled is reduced.

The major impacts of the heavy fuel properties on combustor design are the liner metal temperature and carbon formation. The degree to which the fuel has been atomized is an important influence on both. By using a finely atomized spray such as that produced by the prefiring airblast nozzle, flame radiation can be reduced by as

much as 75 percent in the intermediate zone of the combustor. All liquid fuels for the MS9001E and MS7001EA are, therefore, air atomized at the fuel nozzle. Typical atomizing air pressure ratios (fuel nozzle air pressure/compressor discharge pressure) are in the range of 1.2 to 1.4 for light distillate fuels, with higher ratios required for heavy fuels. Fuels with kinematic viscosities of up to $20 \times 10^{-6} m^2/s$ can be successfully burned using atomizing air. The required pressure ratio is determined largely by experiment and consideration of several design factors including emissions, combustor metal temperatures, temperature profiles, and carbon build up.

Transition Piece

On the multiple combustor arrangement of the MS7001EA and MS9001E, the transition piece, which channels the high temperature gas from the combustion liner to the first-stage nozzle, is very short and easily cooled by air flowing from the compressor. The attachment point of the support bracket is jet film cooled as shown in Figure 8.

The original MS7001 transition pieces had certain difficulties which have been corrected by increasing the metal thickness and eliminating the flat panels which were prone to vibration. This design is shown in Figure 8. The positive curvature (bulge) stiffens the body and eliminates the vibration failures.

The MS9001E gas turbine uses canted combustors as opposed to the in-line configuration of the MS7001EA. As a consequence, the MS9001E transition pieces are a shorter, simpler design which is inherently less susceptible to vibration and wear. An exploded view of the MS9001E transition piece is shown in Figure 9.

Figure 8. MS7001EA transition piece

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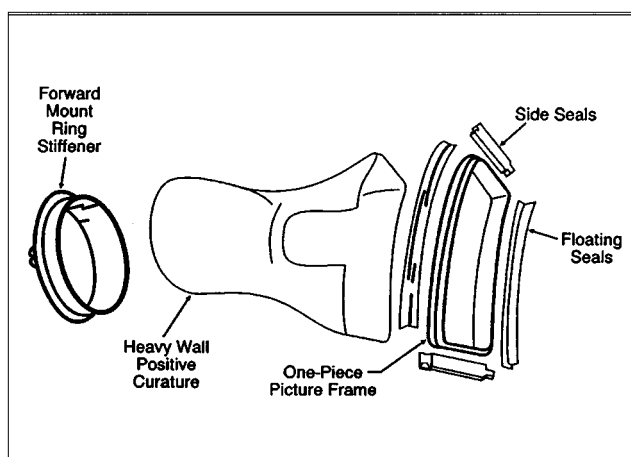
Figure 9. MS9001E transition piece

TURBINE GAS PATH MATERIALS AND CORROSION

Introduction

There are a number of constraints involved in the development and choice of materials for the hot gas path components of a gas turbine. High temperature strength, manufacturability, and cost are some examples. When operating with ash-bearing oils, one of the most important considerations is corrosion resistance.

For more than 35 years, GE has maintained a continuing program to improve the tolerance of machines to the corrosive contaminants sodium (Na), potassium (K), vanadium (V), and lead (Pb) from air and fuel. The results of this program include the use of large, heavy-walled parts, corrosion-resistant materials, protective coatings, and component cooling.

Mechanism of Corrosion

Hot corrosion will take place if metallic compounds containing Na, K, Pb, or V are deposited or condensed on the surface of hot-section components. The rate of corrosion attack depends on the concentration and composition of the contaminants, the material properties, and the temperature and pressure at the surface.

Two competing mechanisms are involved:
- Condensation of corrosive deposits is increased by lower temperature and higher pressure.
- Chemical reaction rates are increased at higher temperature.

An example of this is the observation that cor-rosion can be more severe at lower temperatures than at higher temperatures (e.g., bucket fillets, latter stage buckets, intermittent operation at very low firing temperatures). Figure 10 shows an example of condensation taking place on surfaces over the radial cooling holes in buckets. Similarly, the first-stage nozzle has patches of white deposits where the materials have condensed opposite impingement holes in the nozzle insert used to direct cooling air against the inside surface of the airfoil.

Figure 11 shows the relationship between cor-rosion life and contaminant level at two temperatures. This chart shows that at higher temperatures, more contaminants can be tolerated for a given corrosion life. The decrease in life as a function of contaminant level is the result of increasing condensation of corrosive deposits, until the surface is saturated. At this point, the corrosion life is limited primarily by the kinetics of the corrosion reaction.

Superalloys in high temperature service oxidize uniformly due to the formation and retention of protective oxides. Hot corrosion, however, is initiated by the destruction of protective oxides by reactions with molten compounds of Na, K, Pb and V, resulting in an accelerated attack. The sequence of the hot-corrosion phenomena can be summarized as follows:
- Hot corrosion is usually associated with the presence of both Na and sulfur (S). These combine in the hot gas atmosphere to form Na_2SO_4, which condenses on component surfaces. The Na_2SO_4 reacts with the surface, destroying the protective oxide. Sulfur then penetrates into the metal, forming chromium (Cr) sulfides.
- Depletion of Cr retards the reformation of the oxide film.
- Continuing dissolution of the protective oxide scale allows the hot corrosion process to accelerate.

Pb and V in hot gas streams cause a similar type of attack in which protective oxides are fluxed and their protective effect is destroyed.

Small Burner Test Facilities

The initial concept of small burner test facilities dates back to the middle 1950s at GE. More than 30 million specimen hours of testing have been accumulated with materials at high temperature in both clean and contaminated combustion product environments. Specimens of candidate

Figure 10. Deposits of sea salt on MS7001 first-stage nozzle partitions and buckets. Note condensates in locally cooled surfaces
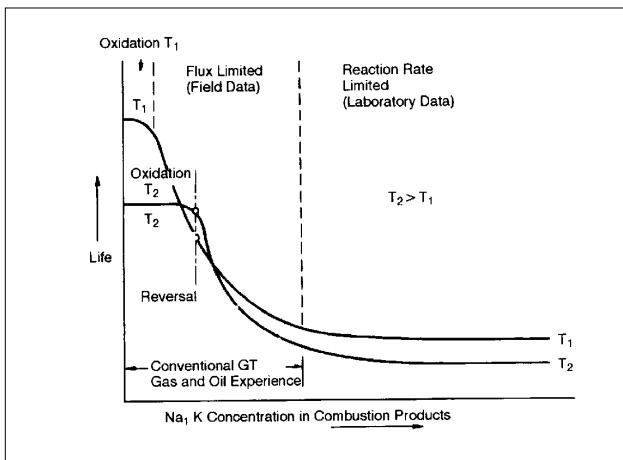
Figure 11. Life vs. alkali concentration for heavy duty gas turbine (schematic)

nozzle and bucket materials are exposed to temperatures ranging from 1400F (760C) to 2000F (1093C) and to controlled contaminant levels.

GE's data bank accumulated over the years is the largest in the world and is used to predict the integrity of nozzles and buckets under a very broad spectrum of fuel and airborne contaminants. The tests serve three purposes:

- To evaluate new and more corrosion resistant materials for nozzles and buckets.
- To evaluate the behavior of materials in combustion products containing the contaminants Na, K, V, Pb singly and in combination.
- To develop a prediction of corrosion parts life as a function of levels of these contaminants and metal temperature.

Oxidation tests are run from 1000 to 30,000 hours at firing temperatures up to 2000F (1093C). The maximum penetrations observed at each test temperature are plotted vs. time on log paper (Figure 12). A line is curve fitted through each set of points. The expression for this line is:

$$P = (Kt)^\lambda$$

where
P = the maximum penetration (mils)
t = time of exposure (hours)
K = constant which is dependent on temperature - T (F)
λ = exponent or slope of P vs. t line and is dependent on T.

Subsequently, a third order polynomial is fitted to the plots of K and λ vs. $1/T$.

Hot corrosion tests are conducted with No. 2
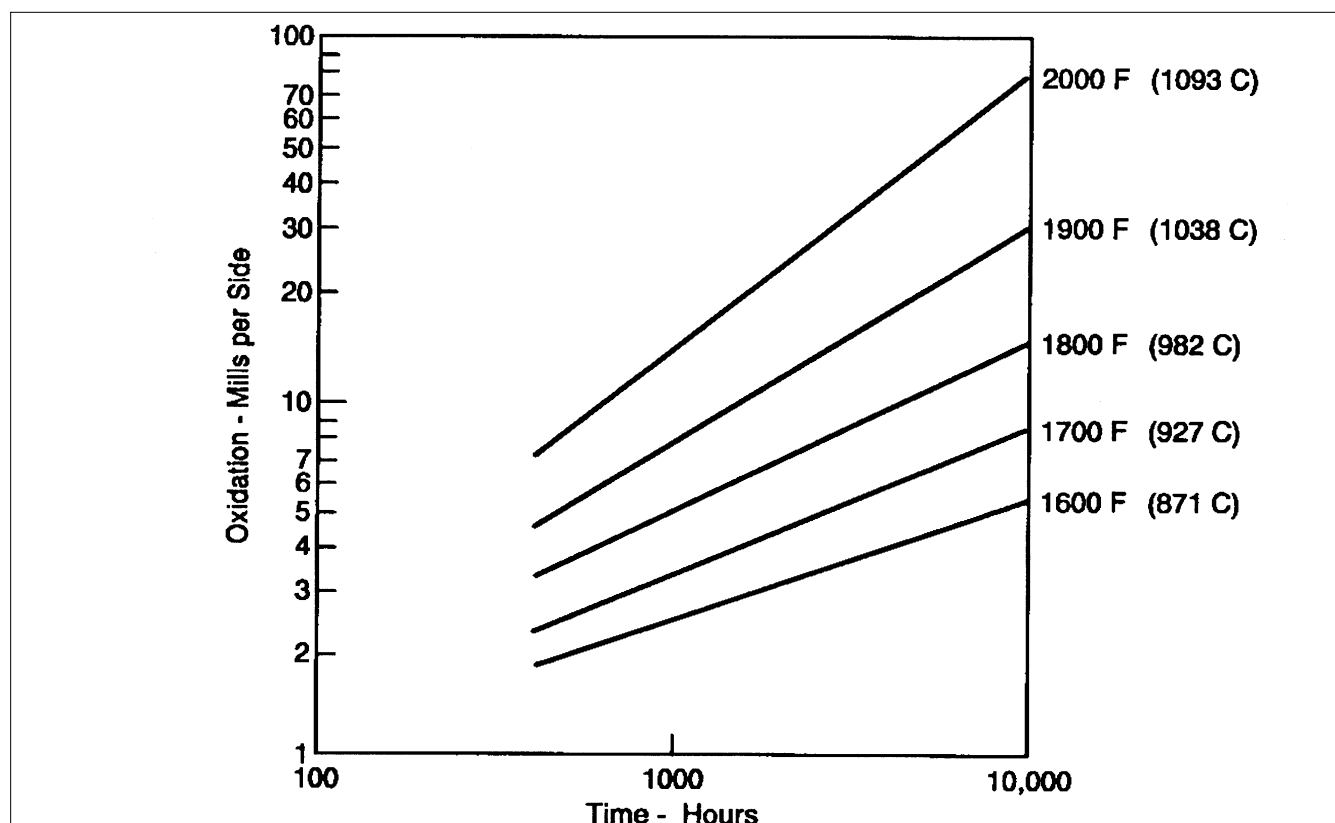
Figure 12. Small burner oxidation test result, FSX414

GT24527

fuel to which detertiary butyl disulfide is added to adjust the sulfur level to 1 percent by weight. A dispersing agent is added to keep the simulated sea water in suspension (sodium equal to 125 ppm).

Tests are most frequently conducted at 1600F (871C) and 1800F (982C), which are the extremes for hot corrosion with respect to the amount of condensible contaminants on the specimen surface at one atmosphere. The specimens at 1600F (871C) are "wet" with condensed salts, while at 1800F (982C) specimens are "dry", and condensation takes place only during daily temperature cycling.

An example of the comparative corrosion behavior of two alloys is shown in Figure 13. The laboratory data for penetration vs. time is shown for U700 and IN-738.

Gas Path Materials

GE's design approach through the past 40 years has been to maintain as high a turbine firing temperature as possible consistent with materials properties and cooling concepts. The result has been a steady, continued growth in firing temperatures, as shown by the upper curve in Figure 14. The lower curve is the creep/rupture strength of

the materials used in the first-stage bucket, the most critical component to support this firing temperature. The introduction of new materials has contributed to the steady improvements in turbine output and efficiency.

GE currently utilizes GTD-111, IN-738, and U500 as bucket materials. All three are precipitation-strengthened nickel-base superalloys with demonstrated corrosion resistance. GTD-111 has the added benefits of a 35F (19 C) increase in rupture strength and greater low-cycle fatigue strength over IN-738. IN-738 is significantly stronger than U500, and is used where greater high temperature strength is required.

First stage nozzles (GE terminology for the stator vanes of the turbine) are subjected to the hottest gas temperatures but to lower mechanical stresses than the buckets. Their function is to direct the hot gases toward the buckets, and they must be able to withstand high temperatures and provide minimal gas turning losses. The nozzles are required to have excellent oxidation and hot corrosion resistance (particularly in sulfurous environments), high resistance to thermal fatigue, relatively good weldability for ease of manufacture and repair, and good castability. The current alloy used for all first stage nozzles is a GE patented

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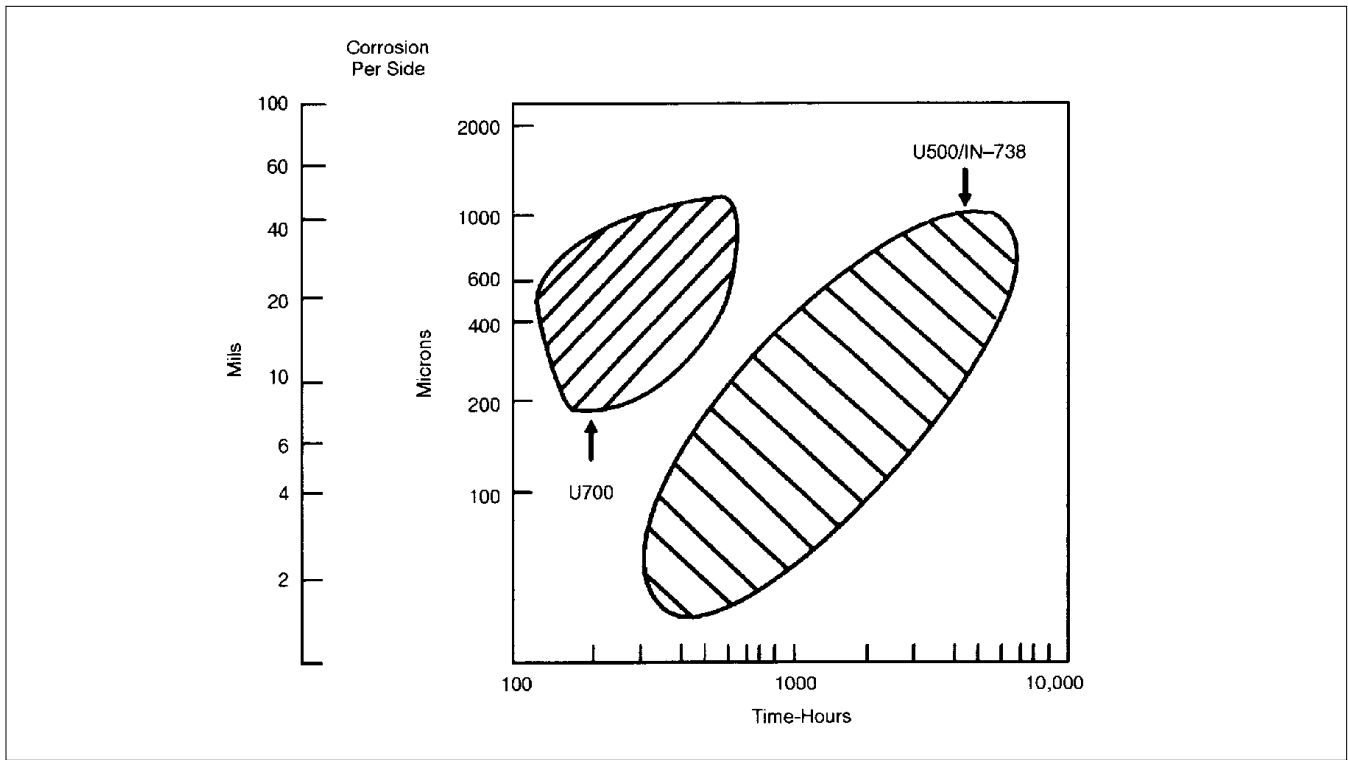
Figure 13. Comparision of U700 and U500/IN738 corrosion resistance
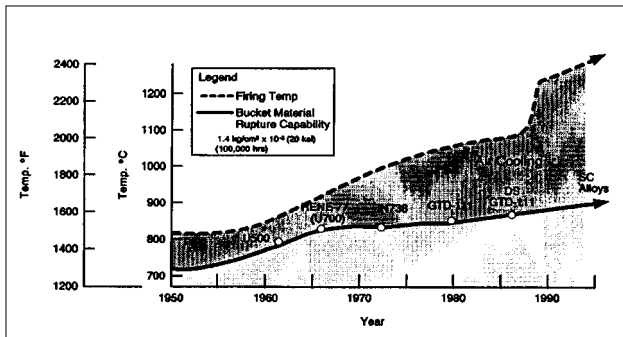
Figure 14. Firing temperature trend and bucket material capability

cobalt base alloy, FSX-414.

Bucket Coatings

The primary purpose of bucket coatings (Ref. 1) is to protect the bucket from corrosion, oxidation, and mechanical property degradation. As superalloys have become more complex, it has been increasingly difficult to obtain both required higher strength levels and satisfactory levels of corrosion and oxidation resistance without the use of coatings. Thus, the trend toward higher firing temperatures increases the need for coatings. The function of all coatings is to provide a surface reservoir of elements that will form very protective and adherent oxide layers, thus protecting the underlying base material from oxidation and corrosion attack and degradation.

Bucket coatings were first used in aircraft gas turbines in the early 1960s. The first of these were diffused aluminum types of coatings. They were evaluated in heavy-duty gas turbines and found to be inadequate because of the longer service times and the higher levels of contaminants in these machines. The presence of increased levels of contaminants gives rise to an accelerated form of attack called hot corrosion. Experience has shown that the lives of both uncoated and coated buckets depend to a large degree on the amount of fuel and air contamination, as well as the operating temperature of the bucket. This effect is shown in Figure 15, which illustrates the effect on bucket life of sodium, a common contaminant.

In addition to hot corrosion, high temperature oxidation is also a concern in the higher firing gas turbines. In today's advanced machines, it is of concern not only for external buckets surfaces but also for internal passages such as cooling holes.

Hot Corrosion

Hot corrosion is a rapid form of attack which is generally associated with alkali metal contaminants such as sodium and potassium reacting with sulfur in the fuel to form molten sulfates. The

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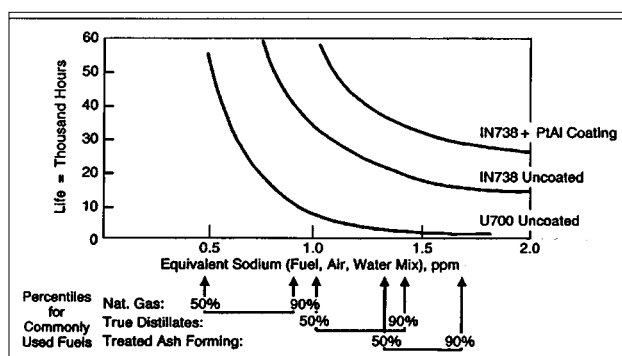
Figure 15. Effect of sodium on bucket
        corrosion life

Figure 16. Hot corrosion (high-temperature
        type)

Figure 17. Hot corrosion (low-temperature
        type)

presence of only a few parts per million (ppm) of such contaminants in the fuel, or equivalent in the air, is sufficient to cause this corrosion. Sodium can be introduced in a number of ways such as salt water in liquid fuel, through the turbine air inlet at sites near salt water or other contaminated areas, or as contaminants in water/steam injections.

There are now two distinct forms of hot corrosion recognized by the industry, although the end result is the same. These two types are high temperature (Type 1) and low temperature (Type 2) hot corrosion.

High temperature hot corrosion has been known since the 1950s. It is an extremely rapid form of oxidation which takes place at temperatures between 1500F (816C) and 1700F (927C) in the presence of sodium sulfate (Na_2SO_4). Sodium sulfate is generated in the combustion process due to the reaction between sodium, sulfur and oxygen. Sulfur is present as a natural contaminant in the fuel.

Low temperature hot corrosion was recognized as a separate mechanism of corrosion attack in the mid-1970s. This attack can also be very aggressive if the conditions are right. It takes place at temperatures in the 1100F (593C) to 1400F (760C) range and requires a significant partial pressure of SO_2. It is caused by low melting eutectic compounds resulting from the combination of sodium sulfate and some of the alloy constituents such as nickel and cobalt. It is somewhat analogous to the type of corrosion called "fireside corrosion" in coal-fired boilers.

The two types of hot corrosion cause different types of attack, as shown in Figures 16 and 17. These are metallographic cross sections of corroded material. High temperature corrosion features intergranular attack, sulfide particles, and a denuded zone of base metal. Low temperature
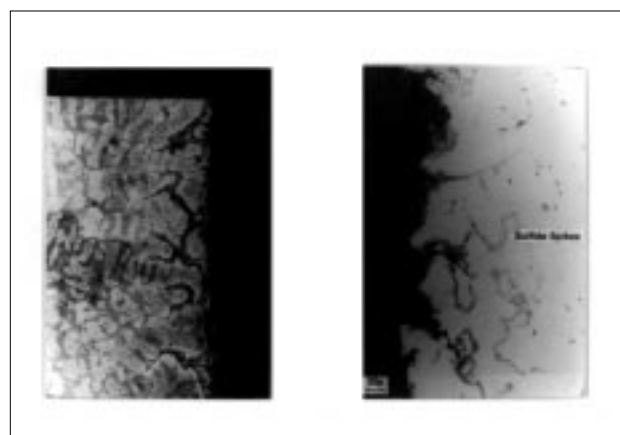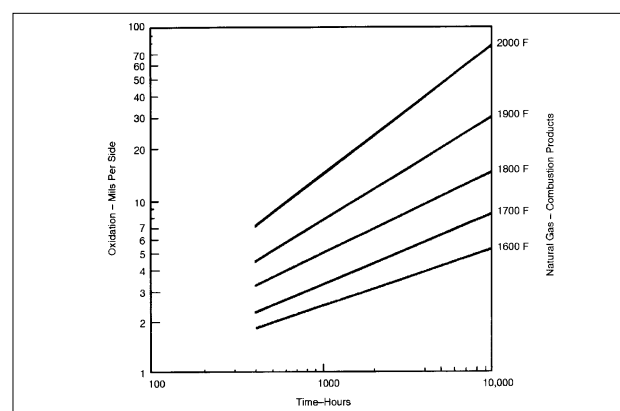
corrosion characteristically shows no denuded zone, no intergranular attack, and a layered type of corrosion scale.

Besides the alkali metals such as sodium and potassium, other chemical elements can influence or cause corrosion on bucketing. Most notable are vanadium, primarily found in crude and residual oils, and lead, most frequently resulting from automobile exhaust emissions or as a transportation contamination from leaded gasolines.

The lines of defense against both types of corrosion are similar. First, reduce the contaminants. Second, use materials that are as corrosion resistant as possible. Third, apply coatings to improve the corrosion resistance of the bucket alloy.

High-Temperature Oxidation

Metal oxidations occurs when oxygen atoms combine with metal atoms to form oxide scales. The higher the temperature, the more rapidly this process takes place, creating the potential for fail-

ure of the substrate material if too much of it is consumed in the formation of these nil strength oxides. Figure 18a shows the microstructure of a coated bucket after about 30,000 hours of service. At the temperatures in this region of the airfoil, no significant oxidation attack of the coating can be seen. By contrast, Figure 18b shows the microstructure of the same coating which has been severely attacked after about the same length of service. At the higher temperatures which must have been present in the Figure 18b case, insufficient aluminum was available in the coating to maintain a protective oxide at the surface, and oxygen was able to diffuse into the interior of the coating structure where it formed discrete, discontinuous aluminum oxide particles. This phenomenon is known as internal oxidation. Such a situation quickly depletes the coating of its available aluminum, rendering it non-protective.

At the higher temperatures (>1650F (899C)), relatively rapid oxidation attack of some materials can occur unless there is a barrier to oxygen diffusion on the metal surface. Aluminum oxide (Al_2O_3) provides such a barrier. Aluminum oxide will form on the surface of a superalloy at high temperatures if the superalloy aluminum content is sufficiently high. Thus, the alloy forms its own protective barrier in the early stages of oxidation by the creation of a dense, adherent aluminum oxide scale. However, many high strength superalloys in use today cannot form sufficiently protective scales because the compositional requirements for achieving other properties, such as high strength and metallurgical stability, do not allow for the optimization of oxidation/corrosion resistance in the superalloy itself. Therefore, most of today's superalloys must receive their oxidation protection from specially engineered coatings.

High-Temperature Coatings

These are the types of coatings that are used on the first stages of all machines, and also might find some application in selective downstream stages. Considerable development has occurred during the past 20 years in the field of high temperature coatings. The result has been a marked increase in the capability of these coatings to resist not only hot corrosion attack over long periods of time, but high temperature oxidation as well. GE heavy duty coatings available today have lives which are 10 to 20 times longer than first generation coatings under a wider diversity of corrosion and oxidizing conditions.

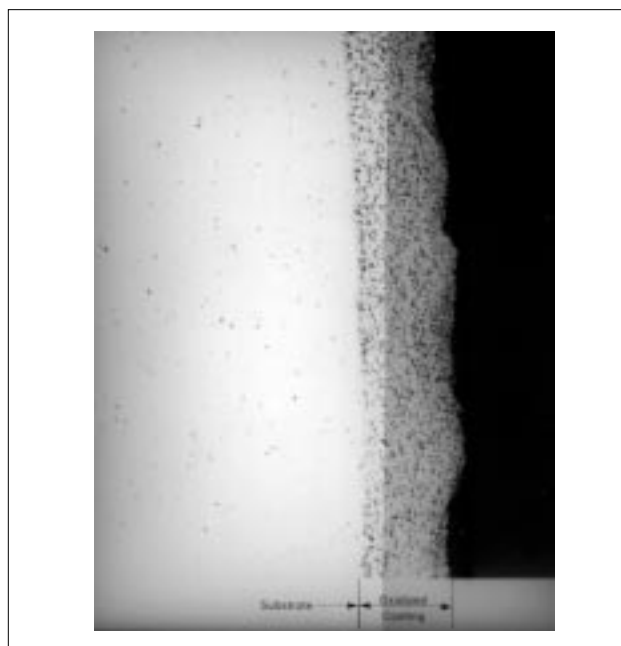We have used two basic classes of coatings dur-

GT21640

Figure 18a. Photomicrograph showing sound miscrostructure of a coated bucket which has been in service
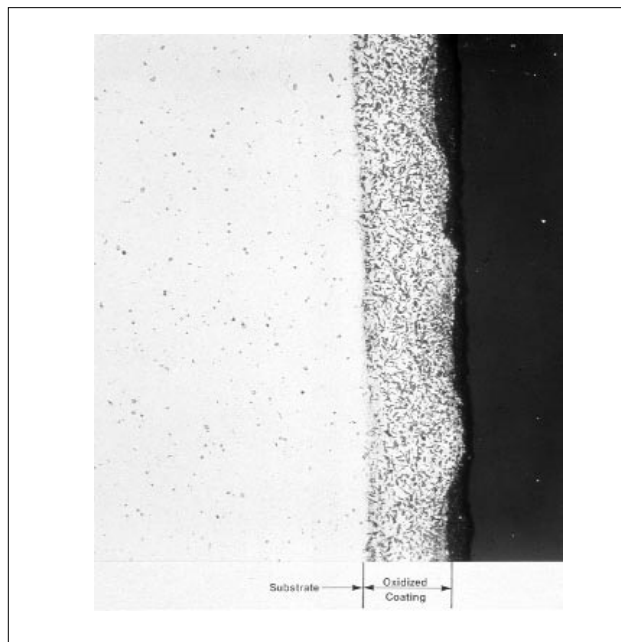

GT21639

Figure 18b. Photomicrograph of a coating on bucket material showing internal oxidation of coating (dark particles)

ing the past 25 years. The first class used was a diffusion coating called platinum aluminide (PtAl). The second class is an overlay coating, PLASMA-GUARD™GT-29 IN-PLUS™.

The development of each of these coating systems was in response to field needs. The platinum aluminide was the original heavy duty coating and

14

addressed corrosion problems seen by a large segment of the fleet in the 1960s. It doubled the corrosion life of the uncoated IN-78 buckets of that time. The PLASMAGUARD™ GT-29™ coating improved that corrosion resistance by an additional 50%. That same high level of hot corrosion resistance is kept in the more recent PLASMA-GUARD™ GT-29 PLUS™, which also has substantially more oxidation resistance, as required by the more advanced machines. PLASMAGUARD™ GT-29 IN-PLUS™ is a two layer coating, with the top layer only applied to the internal surface of the bucket.

A comparison of these first stage bucket coatings is shown in Figure 19, while a more detailed description of each is in the following sections.
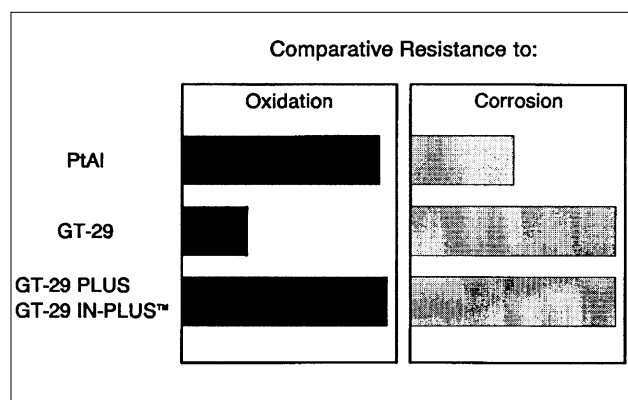
Figure 19. Types of coatings

Platinum-Aluminide Coatings

All first stage buckets have been coated since the late seventies. Up until mid-1983, the coating used by GE on most first stage buckets was a platinum-aluminum (PtAl) diffusion coating. This coating was selected over the straight aluminide coatings because it provided superior corrosion resistance both in burner test rigs and in field trials. The platinum-aluminum coating is applied by electroplating a thin (0.00025 in. (0.06635mm)) layer of platinum uniformly onto the bucket airfoil surface, followed by a pack diffusion step to deposit aluminum. This results in a nickel-aluminide coating with platinum in solid solution or present as a $PtAl_2$ phase near the surface. The platinum in the coating increases the activity of the aluminum in the coating, enabling a very protective and adherent Al_2O_3 scale to form on the surface.

A Rainbow example of comparative corrosion on PtAl coated and uncoated IN-738 buckets, run
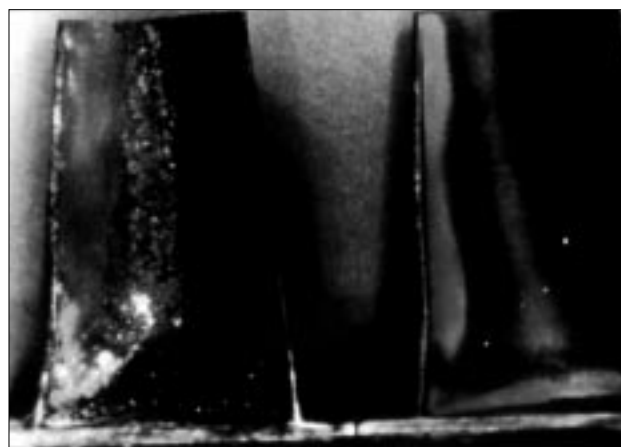
Figure 20. First-stage turbine buckets: coated and uncoated IN-738; 25,000 service hours

side-by-side in the same machine under corrosive conditions, is shown in Figure 20. The two buckets were removed for interim evaluation after 25,000 hours of service. This Aramco unit burned sour natural gas containing about 3.5% sulfur, and was located in a region where the soil surrounding the site contained up to 3% sodium.

The uncoated IN-738 bucket has penetration extending 0.010 to 0.015 inches (0.251 - 0.381 mm), into the base metal over most of the bucket surface. The coated bucket generally shows no evidence of base metal hot corrosion attack, although some of the bucket areas showed coating thinning. Only at some very small locations on the leading edge of the coated bucket was the coating breached, and then to only a depth of 0.001 to 0.002 inches (0.025 to 0.051 mm).

PLASMAGUARD™ Coatings

The new, GE-developed and patented PLASMAGUARD™ coatings are now our standard first stage bucket coatings - GT-29 PLUS™ for solid buckets, GT-29 IN-PLUS™ for cooled or hollow vaned buckets.

PLASMAGUARD™ coatings are examples of overlay coatings and differ from diffusion coatings such as the platinum-aluminum coatings in one major respect. At least one of the major constituents (generally nickel) in a diffusion coating is supplied by the base metal. An overlay coating has all the constituents supplied by the coating itself. The advantage of overlay coatings is that more varied corrosion resistant compositions can be applied, since the composition is not limited by the base metal composition, nor is thickness limited by process considerations.

PLASMAGUARD™ coatings are applied by the Vacuum Plasma Spray (VPS) process in equipment especially designed to apply this coating in a uniform and controlled manner. In this process, powder particles of the desired composition are accelerated through a plasma jet to velocities higher than those achievable through atmospheric plasma spray methods. The solidification of the powder onto the airfoil results in a much stronger coating bond than can be achieved by using conventional atmospheric plasma spray deposition because of the higher particle speeds and the cleaner, hotter substrate. In addition, much higher coating densities and soundness are achievable using the VPS approach.

The first production VPS facility was installed in Schenectady, N.Y., during the early 1980s. This facility is currently being augmented by a newer, higher capacity and more automated VPS facility in the gas turbine manufacturing plant in Greenville, South Carolina. This facility has the capability to coat the latter stage buckets with PLASMAGUARDTM coatings, as well as provide refurbishment capability for used buckets.

Extensive laboratory corrosion testing was performed on candidate PLASMAGUARD™ coating compositions in the late 1960s to the early 1970s. This led to the selection of GT-29™ as the original PLASMAGUARD™ coating that satisfied the field need for superior hot corrosion resistance compared to the original PtAl coating. This laboratory testing was confirmed by field experience in Rainbow rotors that were installed in the mid-1970s. Nearly 35,000 hours of satisfactory turbine operation have now been accumulated on this coating, as shown in Figure 21.

In the mid-1980s, GE found that more oxidation resistance was required for the higher firing temperature gas turbines (generally above 1950F (1065C) in air cooled machines and above 1750F (954C) in uncooled machines). This led to the introduction of the patented coating called PLAS-MAGUARD™ GT-29 PLUS ™ that combines the demonstrated hot corrosion protection of GT-29™ with a substantial increase in oxidation protection. The enhanced oxidation protection offered by GT-29 PLUS™ is gained from an increased aluminum content in the outer region of the coating matrix. In service, the higher aluminum content of the GT-29 PLUS™ forms a more oxidation-protective aluminum oxide layer that greatly improves the high temperature oxidation resistance. Recently, PLASMAGUARD™ GT-29 IN-PLUS™ has been introduced for advanced
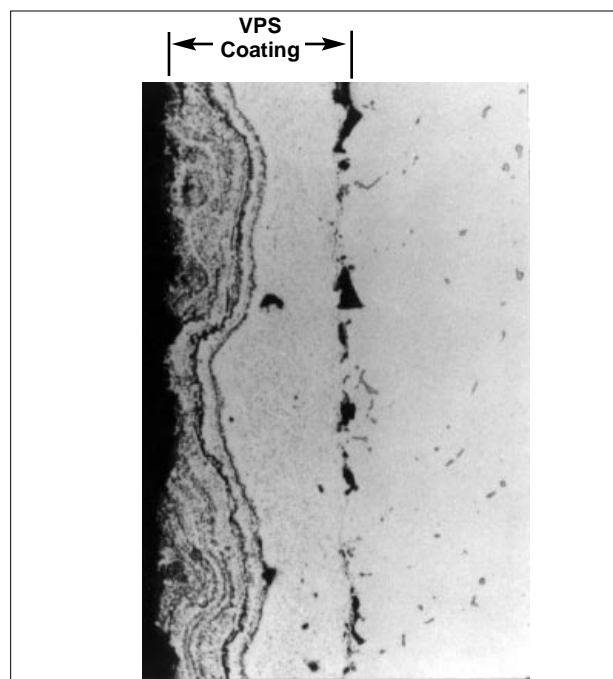

Figure 21. VPS coating after 34,943 hours of turbine exposure – pressure face

cooled and hollow vaned buckets. This coating applies a diffused, aluminum rich layer on those inner passages, cooling holes, and surfaces to protect against oxidation which would otherwise occur.

## Buckets and Nozzles For Heavy-Oil Application

The cooling circuitry for the nozzles and buckets has been designed to avoid plugging by fuel ash deposits. The first and second stage buckets use internal convective cooling to maintain low metal temperature. This cooling system is designed to provide an exit for cooling air at the bucket tips (Figure 22), where these exits are protected from ash impingement. Figure 10 also shows that the air exit holes in the bucket tip remain open and unplugged after long-term operation.

The MS7001EA and MS9001E first-stage nozzle cooling circuits and cooling air exit passages have been modified to further minimize the occurrence of plugging by ash deposits (Figure 23). Should the suction side film holes experience plugging by ash deposits, the forward cavity chamber cooling flow would then pass through the rib bypass holes into the aft cavity chamber. The cooling air entering the aft cavity chamber exits from the trailing edge region of the nozzle vane
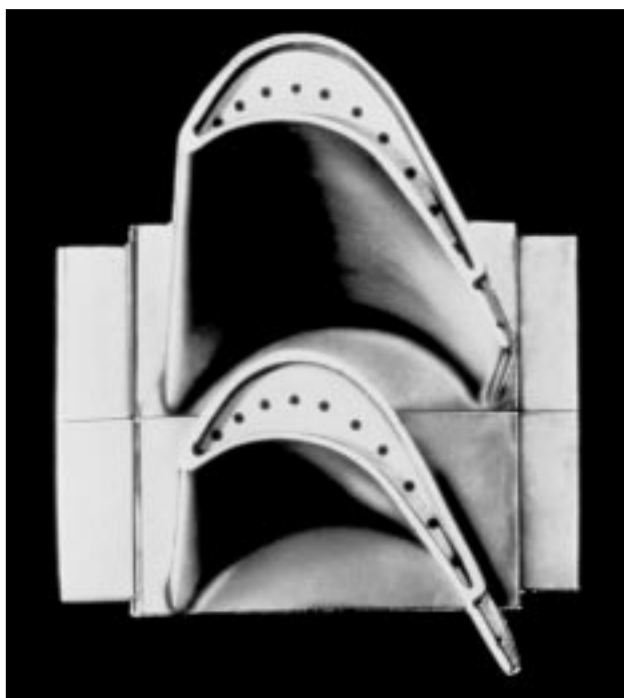
Figure 22. MS7001 first-stage turbine buckets, radial view
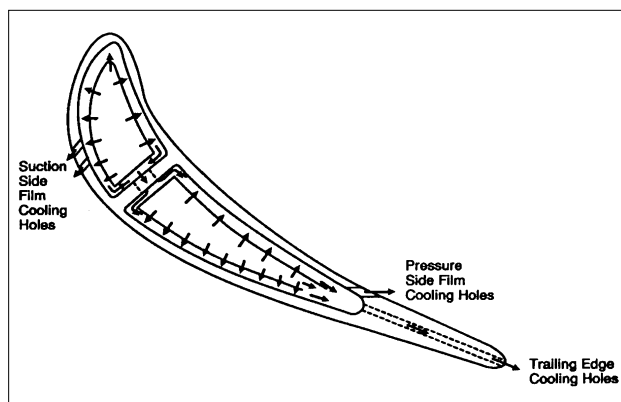
Figure 23. MS7001EA first-stage nozzle for heavy fuels

through trailing-edge rectangular slots and through large pressure-side film holes which are not subject to plugging by ash deposits.

Borescope Inspection Techniques

GE gas turbines have provision for borescope inspections of internal conditions, thereby minimizing disassembly and outage time.

The borescope access is provided at strategic locations in the turbine for inspection of the compressor and turbine (Figure 24). Evaluation of the results of borescope inspections, in conjunction with the practice of periodically monitoring per-
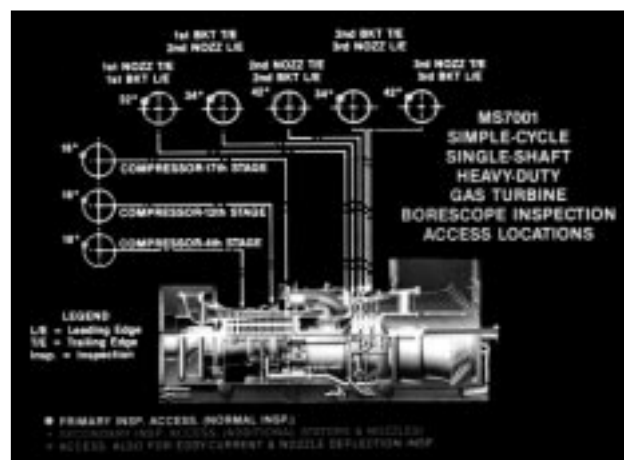
Figure 24. MS7001EA simple-cycle, single-shaft, heavy-duty gas turbine borescope inspection locations

formance, will determine the most economical time for a scheduled outage. The timing of the disassembly outage thus becomes a judgment based on known machine condition, rather than the historical approach based upon generalized operating factors and usage.

TURBINE DEPOSITS

Nature of Deposits

Ash-bearing fuel oils generally require the use of suitable additives to inhibit corrosion. A discussion of additives is presented in the "Fuel Additives" section. Deposits of ash from these fuels can adhere to the hot gas path parts and restrict the flow of gas, thereby reducing the output and efficiency of the turbine. The rate at which these deposits accumulate, and the ability to remove them, will depend upon a number of factors including fuel composition, treatment effectiveness, turbine design, and firing temperatures.

The nature of the deposits changes with temperature. Figure 25 shows an example of deposits formed at 1750F (954C) on a cooled turbine nozzle partition. The deposit next to the metal is water soluble $MgSO_4$. The deposits on top of this layer are insoluble MgO. These deposits, because they are insulated from the nozzle surface, were formed at higher temperature than those next to the metal. The relationship between temperature and sulfur content, both of which determine the equilibrium between MgO and $MgSO_4$, is also given in this figure.
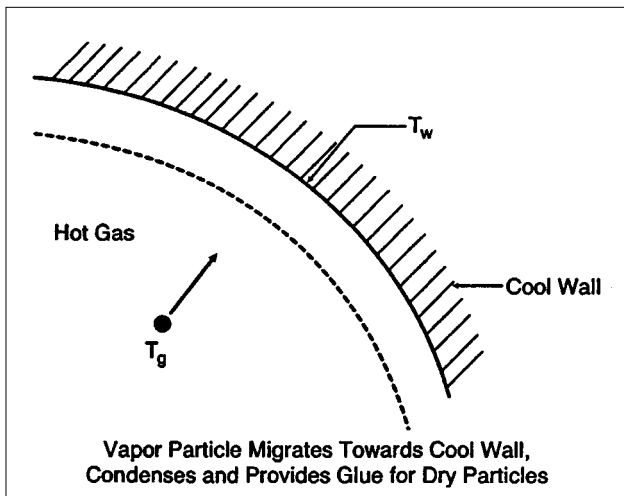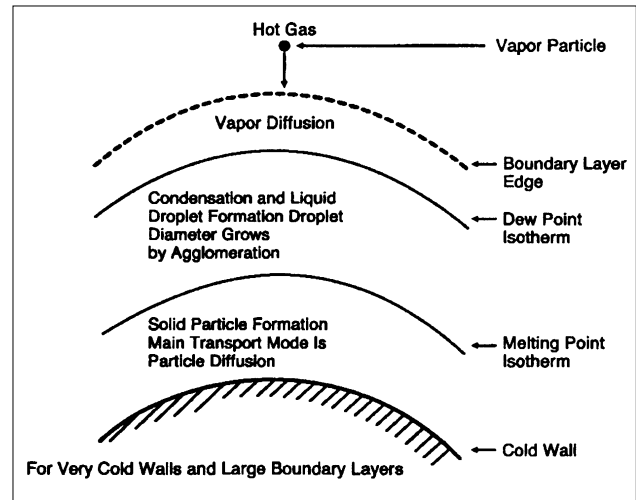
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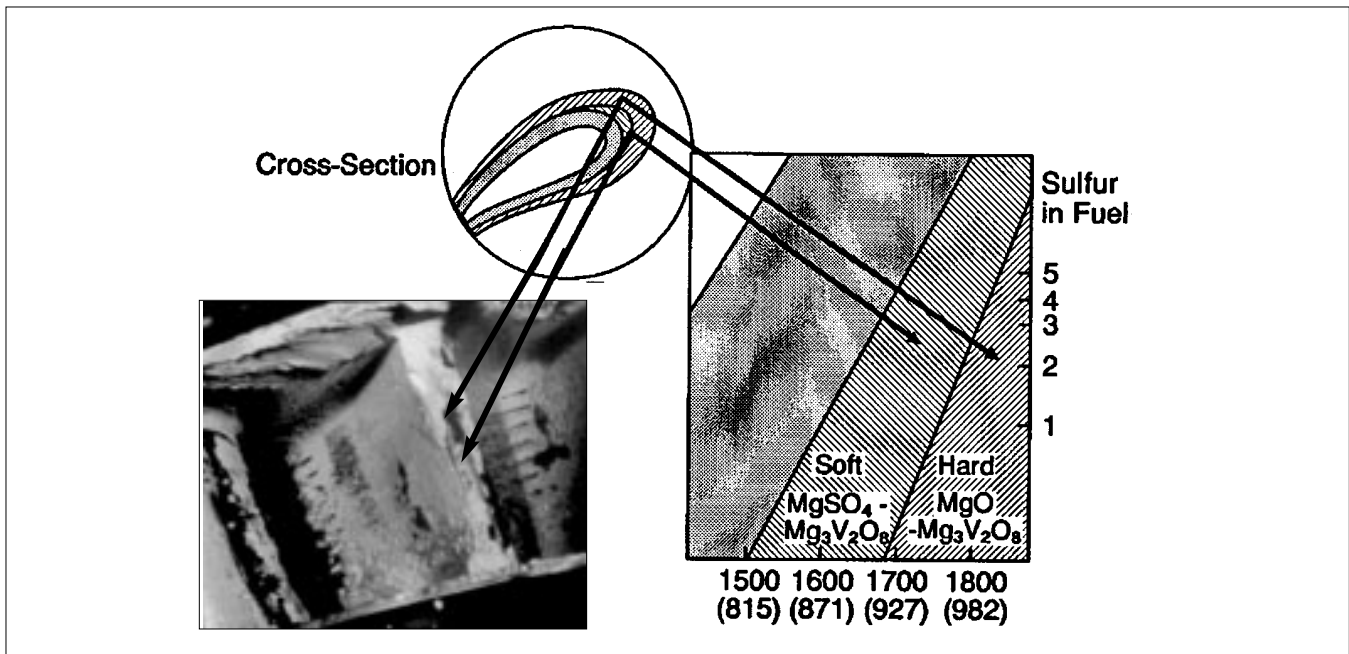
Figure 25. Layered ash deposit on first-stage nozzle

GT00103B

Figure 26. Vapor diffusion

GT24219A

**Figure 27. Vapor diffusion/condensation/
solidification**

GT24220A

Four distinct processes may result in ash particle deposits on the nozzle airfoils:
- Vapor particles migrate through the boundary layer toward the cool wall. If the boundary layer temperature is below the dew point, condensation takes place at the wall (Figure 26).
- If the temperature of the boundary layer is below the melting point of the species, and the particle has a long enough residence time in the boundary layer, then the vapor particle condenses and solidifies before it reaches the surface. If the liquid particle is at a temperature well below its sintering temperature by the time it gets to the surface,

the probability of sticking to the surface is reduced (Figure 27).
- Liquid and solid particle impaction occurs when ash particles form nuclei for the condensation of low-melting point species either inside or outside of the boundary layer. The condensate which the solid particle may pick up forms the binder which causes the particle to stick to the wall Figure 28).
- A liquid droplet deviates from the streamline and impacts the wall due to its own inertia (Figure 29).

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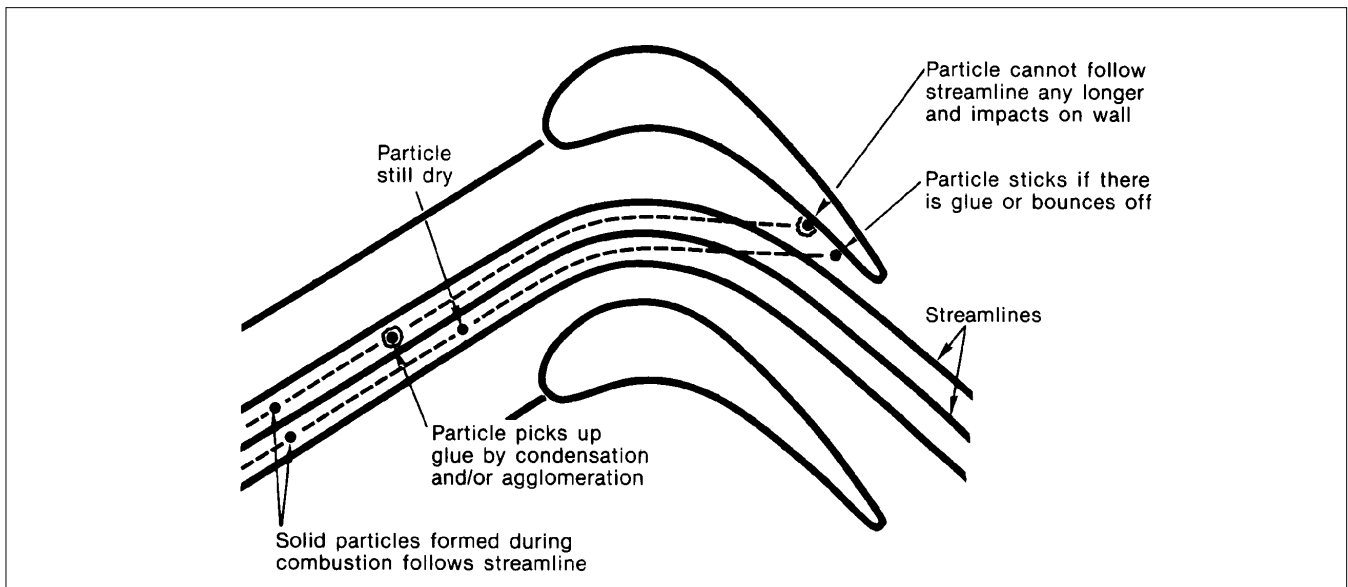
Figure 28. Solid particle impaction
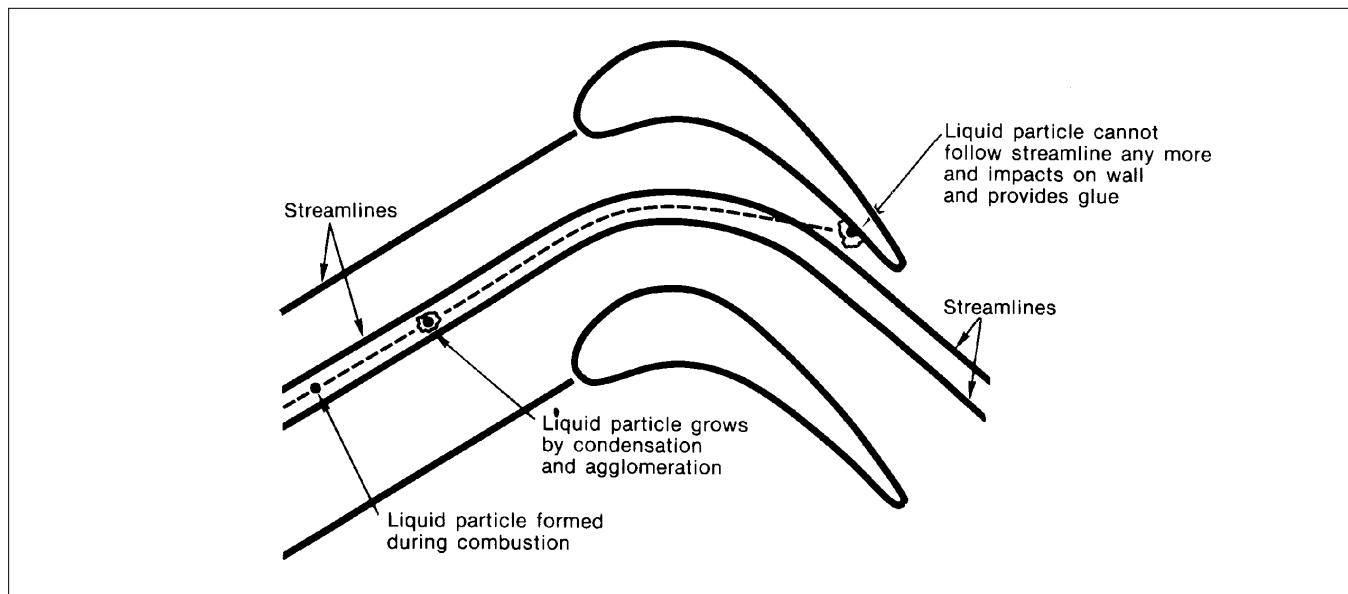
GT24221A

Figure 29. Liquid particle impaction

GT24222

Turbine Simulator Tests

In the early 1960s, a test facility to simulate the combustion system and turbine first-stage nozzle was constructed at the GE Research and Development Center to study deposit forming characteristics of various fuels. This "Turbine Simulator" has been extremely valuable for studying, under actual machine conditions of pressure and temperature, the nature of turbine deposits and the rate of deposit formation, as well as development of techniques for deposit removal. Heated, non-vitiated air is delivered to the test apparatus (Figures 30 and 31) at flows up to 8

GT8915

Figure 30. Turbine simulator, high-pressure test facility

19
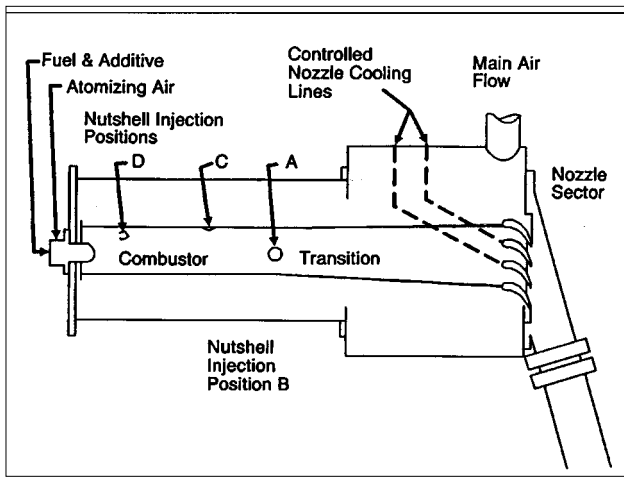
Figure 31. Turbine simulator test section

lbs/sec (3.6 kg/sec) at a pressure ratio up to 6 to 1. The combustor is scaled from the MS5000 gas turbine. The turbine nozzle is part of an MS3002 air-cooled nozzle sector, and the transition section is matched to these parts.

Sixty-two tests of 100 hours each have been conducted in this facility at firing temperatures ranging from 1000F (538C) to 2100F (1150C). Residual fuel and No. 2 distillate doped with Na, V, Mg, Si, etc., to simulate various grades of heavy oils have been burned, and the deposit character-

istics have been studied. Methods of removing these deposits during and after operation have been developed. In one test, deposits formed at 1500F (816C) on the first-stage nozzle partitions were hydrated, causing them to swell. On subsequent refire, the deposits spalled off. Nutshells injected into the combustors at full speed under load remove much of the ash.

At firing temperatures above 1700F (927C), (depending on the sulfur content of the fuel), MgO deposits are more likely to form then $MgSO_4$, as indicated in Figure 25. Generally, $MgSO_4$ can be completely and quickly removed by water or wet steam. MgO deposits, however, are insoluble and more difficult to remove.

Since high turbine firing temperatures are desirable for high output and high efficiency, it was necessary to find effective methods to remove deposits formed at high temperatures. A large number of tests were devoted to this need. A wash/soak/refire procedure was developed for removing ash deposits during a series of tests conducted in the turbine simulator.

In these tests, removal of the deposits formed at 1950F (1066C) firing temperature (Figure 32) was accomplished by the following sequences:

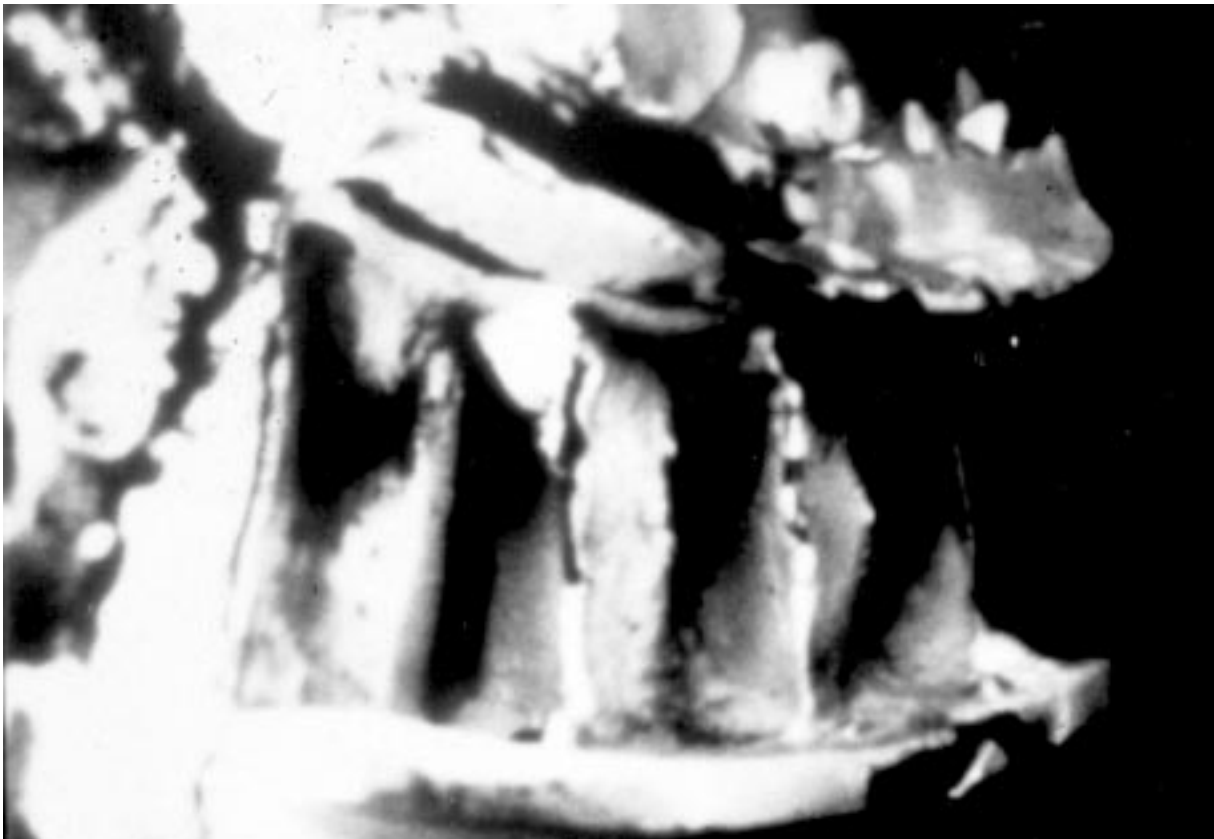1. Warm water was injected into the combus-
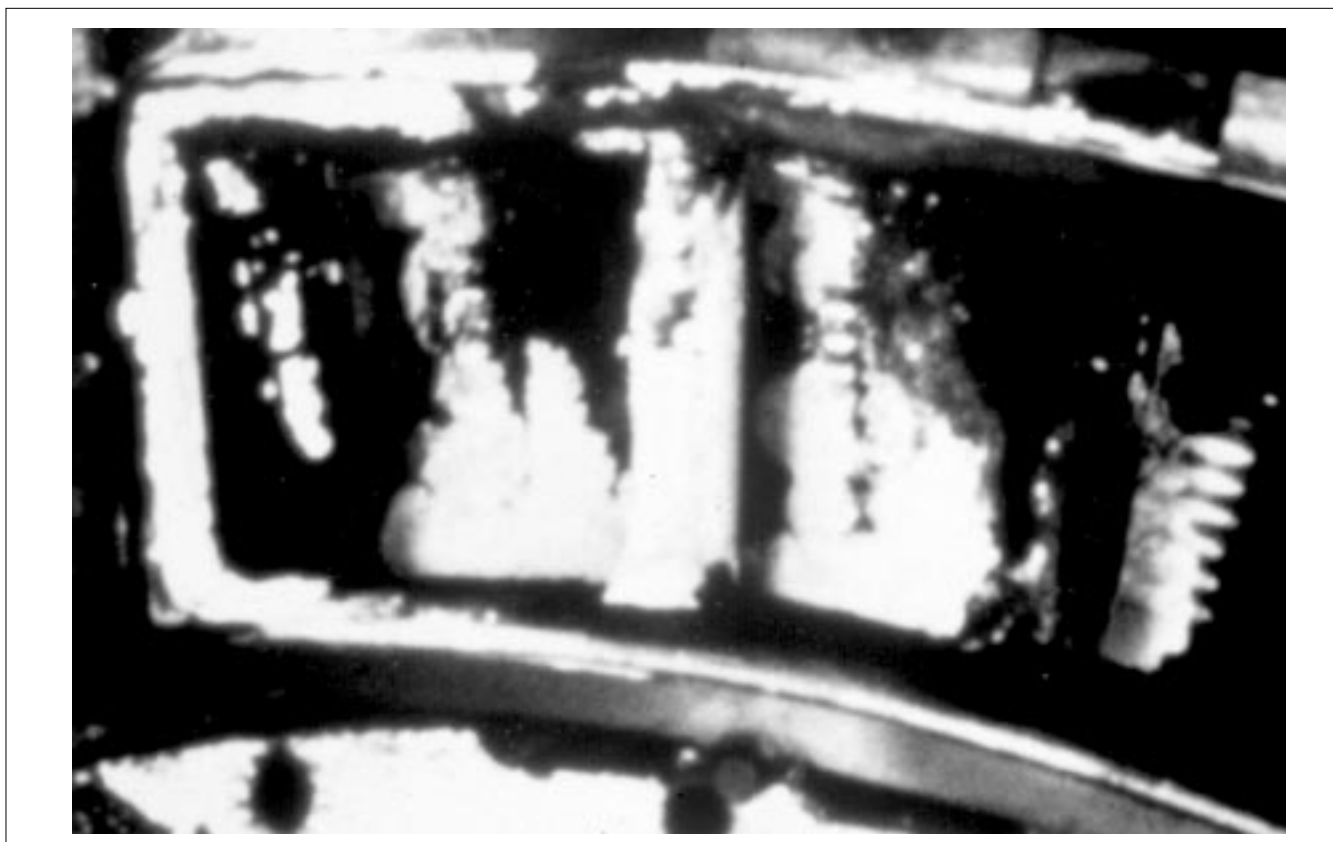

Figure 32. Nozzles before washing

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Figure 33. Nozzles after water washing

GT23876

tors for 30 minutes. This removed 60-70 percent of the deposits. Additional washing had no noticeable effect. The appearance of the deposit after this sequence is shown in Figure 33. About 30-40 percent of the original deposit remained.

2. The rig was refired to 1950F (1066C) for one hour. Inspection after shutdown showed that the nozzle was essentially 100 percent clean (Figure 34). It was surmised that water penetrated through the porous deposit during the water wash and when the rig was refired, the water flashed into steam creating sufficient pressure to fracture the deposits.

This wash, soak, refire procedure was repeated in several tests and has been proven in the field in removing deposits formed at 1850F (1010C) firing temperature. Refiring to full speed at no load after the water soak removes the deposits.

Field Experience

Two examples of residual fuels experience on the MS7001 gas turbines are of interest with respect to nozzle deposition rates and deposit removal (Table 3).

The difference in deposit rates is attributed to different amounts of vanadium and sodium in the fuel and the differing hours of operation. The turbine in Case II was run continuously for 185 hours, and showed a low deposit rate of 1.5 percent per 100 hours. Each combustion chamber was washed with 25 gpm (1.6 lps) water flow for 10 minutes. In both cases, turbine cleaning (wash, soak and refire), completely restored the turbine performance. Figure 35 is a picture of the combustion liner from the same turbine showing no blockage of the cooling passages.

FUEL ADDITIVES

Background

The successful burning of heavy fuels in gas turbines depends on the use of additives to prevent hot corrosion of hot gas path components. The cause and nature of this type of corrosion is discussed in the "Turbine Gas Path Materials and Corrosion" section. Briefly, it is due to vanadium or to vanadium plus sodium trace contaminants in heavy fuels - crude oils, residual oils and blended residual oils - which destroy protective oxide films on hot gas path parts. Certain selected crude oils contain less than the 0.5 ppm threshold limit for vanadium inhibition, but most heavy fuels have
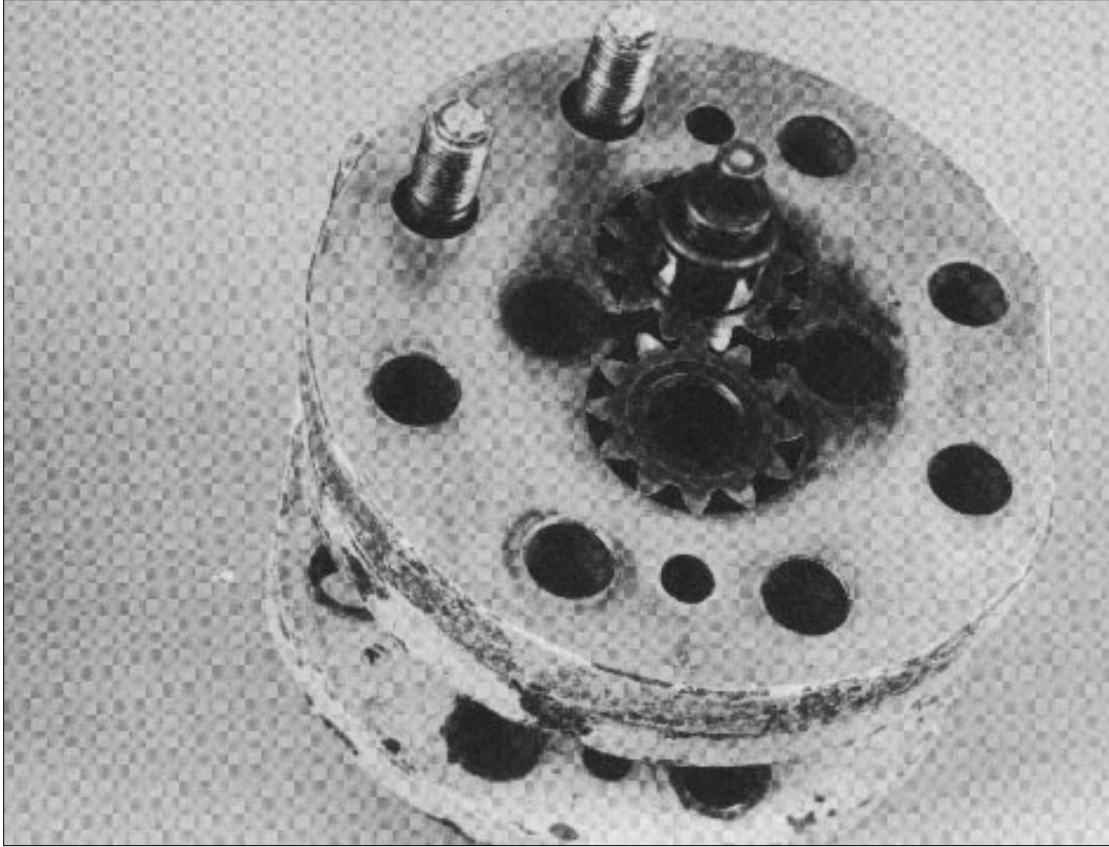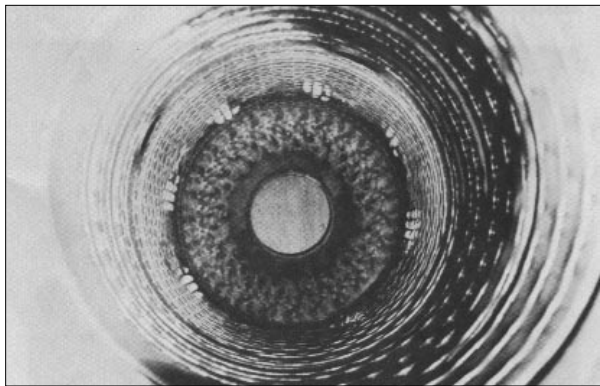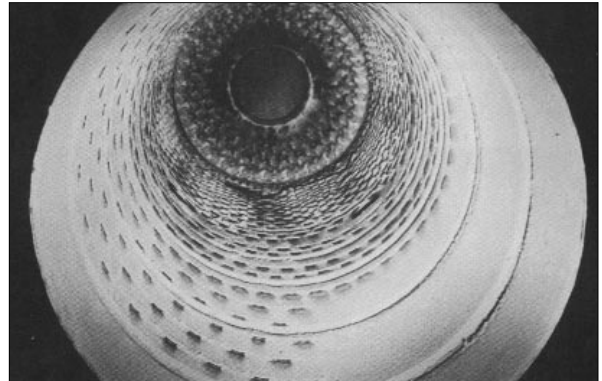
GT23877

Figure 34. Nozzles after water washing and refiring

Before

After

Figure 35. Combustion liner before and after wash, soak and refire

Table 3. RESIDUAL FUEL EXPERIENCE		
	Case I Industrial Base-Load Power Generation	Case II Electric Utility Mid-Range Power Generation
Operation	Continuous Between Turbine Wash	Intermittent, Daily Turbine Wash
Firing Temperature	1750 F (954 C)	1850 F (1010 C)
V in Fuel	90 ppm	27 ppm
Na in Fuel	1.5 ppm	0.2 ppm
Mg in Fuel	300 ppm	90 ppm
Plugging Rate	4%/100 hrs	0.3%/100 hrs

over 0.5 ppm of vanadium and require an inhibiting additive.

Additives for hot corrosion inhibition are based on magnesium, although some commercial additives also contain other elements including silicon, chromium, and aluminum for special applications. The basic requirements for an inhibitor are that it form a high melting point, non-corrosive ash with the harmful trace metal contaminants in the fuel, and that the hot gas path deposits from this ash do not cause excessive maintenance of the turbine.

Other additives are occasionally used in gas turbine fuels for fuel storability improvement or combustion improvement (smoke reduction). These additives are not included in this discussion, due to their specialized and less frequent applications.

Magnesium-Based Additives

Commercial magnesium-based vanadium inhibitors used in gas turbines include several chemical types. Operating experience and laboratory data indicate that they are equally effective in preventing vanadium hot corrosion at the same magnesium level in the treated fuel. They do differ, however, in cost and application considerations, which can affect the additive selection for a specific turbine installation.

There are three generic types of magnesium-based additives: water-soluble, oil-soluble, and oil-dispersible. Magnesium sulfate (Epsom salt) is the water-soluble additive. It is used as a 10 to 20 percent water solution of magnesium sulfate which must be emulsified into the fuel. Since it does not form a stable emulsion in the fuel, the solution must be injected into the fuel just prior to use. Oil-soluble inhibitors are proprietary products which blend readily and uniformly in the fuel to form stable mixtures. Oil dispersible inhibitors are stable suspensions of very finely divided solid magnesium compounds either in an oil vehicle or a water vehicle. They are outgrowths of "fireside" additives used in boilers for corrosion and ash deposit control. Oil-dispersible inhibitors form stable mixtures in the fuel if some mixing is provided.

The properties of these three generic types of magnesium-based additives are outlined and compared in Tables 4 and 5. The final selection will depend on economic and operating considerations, which in turn depend on the vanadium level in the specific fuel, the size of the turbine installation, and the operating duty cycle of the turbine.

Table 4. COMPARISON OF MAGNESIUM-TYPE VANADIUM INHIBITORS			
	Oil-Soluble Magnesium Sulfonate)	Water-Soluble (Magnesium Sulfate)	Suspension (Magnesium Oxide or Hydroxide)
Advantages	• Simplest Handling • Very Low Na, K, and Ca Levels	• Lowest Cost per Unit of Magnesium • Low Na, K, and Ca Levels	• Intermediate Cost • Highest Magnesium Content • Mechanical Dispersion Not Required; Only Mild Tank Agitation
Disadvantages	• Highest Cost per Unit of Magnesium	• Extensive Handling Required • Mechanical Dispersion Required	• Limited Field Experience; Performance Effects Have Not Been Fully Evaluated • Possibly Higher Ca, Na and K Levels (Significant Only at High Vanadium Levels in Some Products) • Allowable Maximum Particle Size Limits
Relative Additive Cost* (For Same Mg Content)	1.00	0.20	0.25 - 0.60

*Based on Cost of Source

Table 5
APPLICATION OF MAGNESIUM ADDITIVES

Additive Type	Additive Form as Delivered	Additive Form as Used	Fuel Treatment Method	Typical Usage Rate Gal. Additive per 1,000 Gal. of Fuel
Water-Soluble (Magnesium Sulfate)	Solid Crystals in Bags	Water Solution, 12-20% MgSO₄ (Low Na, K, Ca Water Required)	Mechanically Dispersed, On-Line Injection	5.5 (12% Solution)
Oil-Soluble (Overbased Magnesium Sulfonate)	Pumpable Liquid in Drum or Tank Trucks	As Received	Self-dispersing, On-line or Pretreated Fuel Storage	1.7
Suspension (Magnesium Oxide or Hydroxide)	Pumpable Liquid in Drums or Tank Trucks	As Received	On-line or Pretreated Fuel Storage With Some Tank Mixing	0.4 - 0.6

*For 50 ppm of Vanadium in Fuel and 3/1 Weight Ratio of Mg/V

Water-soluble (magnesium sulfate): Magnesium sulfate usually has the lowest cost per unit of magnesium, an important consideration when the vanadium level in the fuel is high and/or the rate of fuel consumption is high. On the negative side, magnesium sulfate is the most difficult to handle and to mix with the fuel. Only low sodium level magnesium sulfate should be used, and the water used to dissolve it should also be low in sodium.

Oil-soluble (magnesium sulfonate): These commercial proprietary additives are similar to certain additives used in automotive crankcase lubricating oils. Due to their ease of application and handling, they have been widely used in recent years. The cost for use with high-vanadium fuels and/or high fuel usage is a negative factor for this type of additive.

Oil dispersible: These are concentrated stable suspensions of very finely divided magnesium oxide or magnesium hydroxide in distillate oil or less frequently water. These concentrated suspensions disperse readily in the liquid fuel to form uniform mixtures which may be stored for a limited time if some mixing is provided. These additives are the most concentrated, with the least shipping and storage problems. This may be a significant factor where large quantities of additive are required. The presence of fine solids presents a risk of abrasive wear of fuel pumps and flow dividers unless the particles are kept extremely small. Additives of this type intended for boiler use may have too high concentrations of trace contaminants (sodium, potassium and calcium) and too large size particles for gas turbine application. Only additives approved and verified for gas turbine application should be used.

Magnesium Additive Dosage Rate

To prevent vanadium hot corrosion in the turbine hot gas path, a minimum ratio of magnesium-to-vanadium is required. Higher rates than necessary should be avoided to avoid excessive additive cost, to minimize stack particulate emissions, and to avoid higher rates of combustion ash build-up in the hot gas path.

For normal applications, a minimum 3 to 1 weight ratio of magnesium-to-vanadium (Mg/V), is recommended, with a maximum of 3.5 to 1. For residual fuels and blended residual fuels with moderate to high vanadium levels and sodium plus potassium levels of 1 ppm or less after washing, the 3 to1 Mg/V ratio is adequate. This ratio will have to be increased in those special cases of high sodium-to-vanadium ratio in treated fuel, usually crudes with low vanadium levels (0.5-10 ppm). If the sodium-to-vanadium ratio is high, these two elements may interact and cause hot corrosion. This is especially critical when sodium removal to less than 1 ppm is not practical. Increasing the magnesium-to-vanadium ratio above 3-to-1 is recommended in such cases. The magnesium-to-vanadium ratio may have to be increased to about 5 to 1 for sodium-to-vanadium ratios of 1/15, and to about 10 to 1 for sodium-to-vanadium *ratios* of 1/5. Although the magnesium-to-vanadium ratios are high, the total *level* of magnesium required is not significant since this only occurs with low vanadium level fuels. A convenient and economical means of accommodating this requirement would be to maintain a minimum dosage rate for these low vanadium level fuels.

Silicon Additives

Silicon additives have been used to modify gas turbine combustion ash to make it drier, less dense and more friable. Usually silicon has been used in combination with a magnesium additive. The operating advantage sought by modifying the ash is a low ash deposition rate in the hot gas path and/or and ash which is more readily removed by available turbine cleaning techniques.

The effect of silicon additives on the combustion ash deposition rate appears to depend on complex inter-relationship of fuel chemistry, deposit chemistry, and turbine firing temperature. Most of the reported successful use in the past has been at firing temperatures below 1550F (843C). At the state-of-the-art higher firing temperatures, the effect of silicon is complex and is still being studied closely for better understanding.

GE's laboratory experience in the turbine simulator indicates that there is only a limited range of fuel chemistries within which silicon reduced the ash deposit rates in the first-stage nozzle at firing temperatures of 1750F (954C) and 1950F (1066C). Specifically, when the Na/V ratio in the fuel is between 0.01 and 0.5, deposit rates are reduced by a factor of between 5 and 10 fold and are washable by standard water wash-refire procedures. At lower Na/V, ratios field experience has shown no benefit rates. In applications involving waste heat boilers, excessive fouling of fin tubes has been observed.

At higher Na/V ratios (> 0.05), and at firing temperatures between 1750F (954C) and 1950F (1066C), deposit rates are sometimes higher using silicon and are sometimes not removable by washing. One interesting characteristic, however, is that the silicon does render deposits formed at 1950F (1066C) partially removable by nutshell injection during operation. Deposits formed when using magnesium alone at this firing temperature have not been found to be removable by nutshells.

Silicon is usually added with magnesium such that the weight ratio of silicon-to-magnesium-to-vanadium is typically 7:3:1. The silicon-magnesium additive costs about four times more than the oil-soluble magnesium. For typical heavy fuel applications, GE has not recommended the silicon-magnesium additives because of their higher cost and uncertainties in ash deposit rates and removal. However, it is recognized that in special situations, there may be operational and/or economic benefits for use of the silicon-magnesium additives.

TURBINE ACCESSORY SYSTEMS

Heavy Oil Fuel System

The fuel system is installed on the gas turbine accessory base and performs the following functions: pumping to the pressure required by the fuel nozzles; metering the fuel required by the turbine; and metering fuel to each combustor.

Figure 36 presents a schematic of the fuel system. Fuel is received from the forwarding system at the point marked "supply". It flows through the low-pressure filter, stop valve, main fuel pump, and the free wheeling flow divider. The flow divider meters essentially equal fuel to each combustor. The total fuel flow is controlled by a by-pass valve around the main fuel pump which is modulated by the gas turbine SPEEDTRONIC™ control system.

Fuel Pump

The fuel pump employed on the MS7001EA and MS9001E burning crude or residual fuels is a screw-type positive-displacement pump. A cutaway view is presented on Figure 37. Design features which suit it for heavy fuel pumping service are:
- The pump has separately lubricated bearings, with oil supplied from the turbine lube oil system. This eliminates corrosion of the fuel pump bearings by contaminants contained in the fuel being pumped.
- The pump is water cooled, to reduce metal temperatures since residual fuel oil temperature can approach 275F (135C).
- The screws are driven by herringbone gears located at the end of the pump. The mating surfaces of the pumping screws are not in physical contact. Clearances are provided, so mechanical interferences are eliminated.
- The pump elements are corrosion-resistant stainless steel.

Flow Divider

The flow divider consists of multiple mechanically connected pumps having identical capacity which meter fuel to each combustor. The gear which mechanically connects the individual gear pumps is illustrated in Figure 38, and one of the individual gear pumps is shown in Figure 39. The gear pumps are matched, positive-displacement pumps which are forced to run at equal speed.
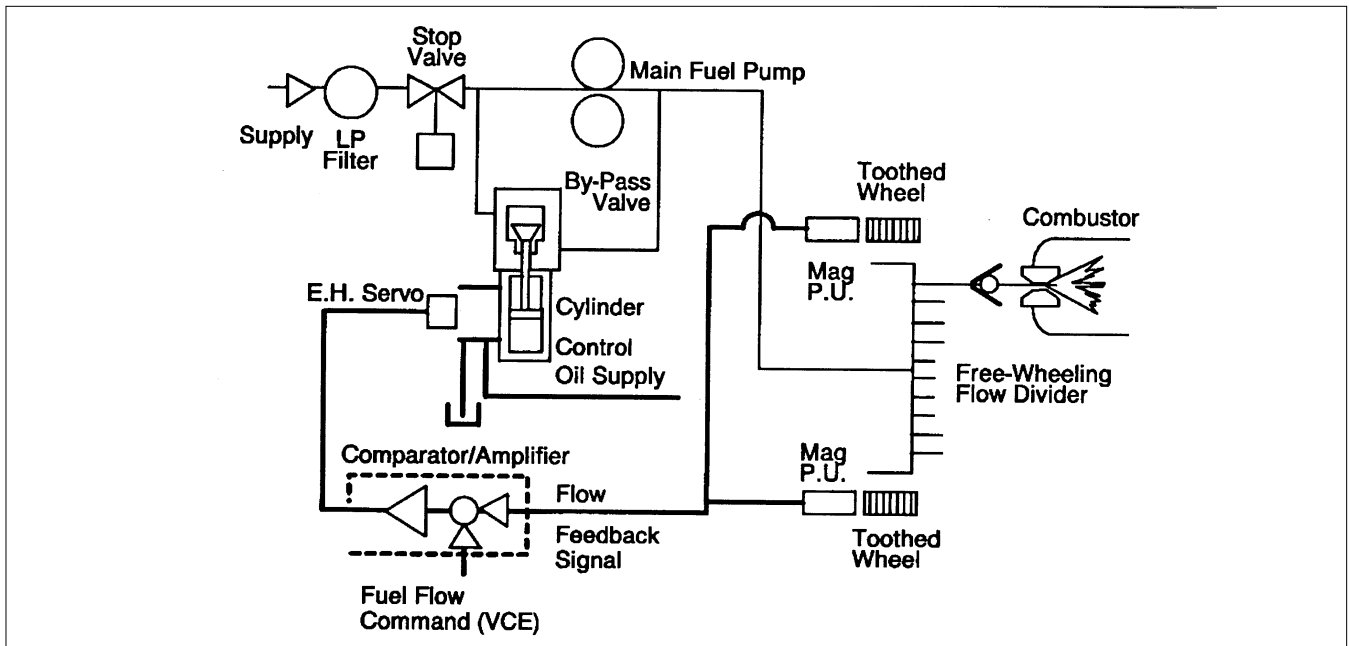
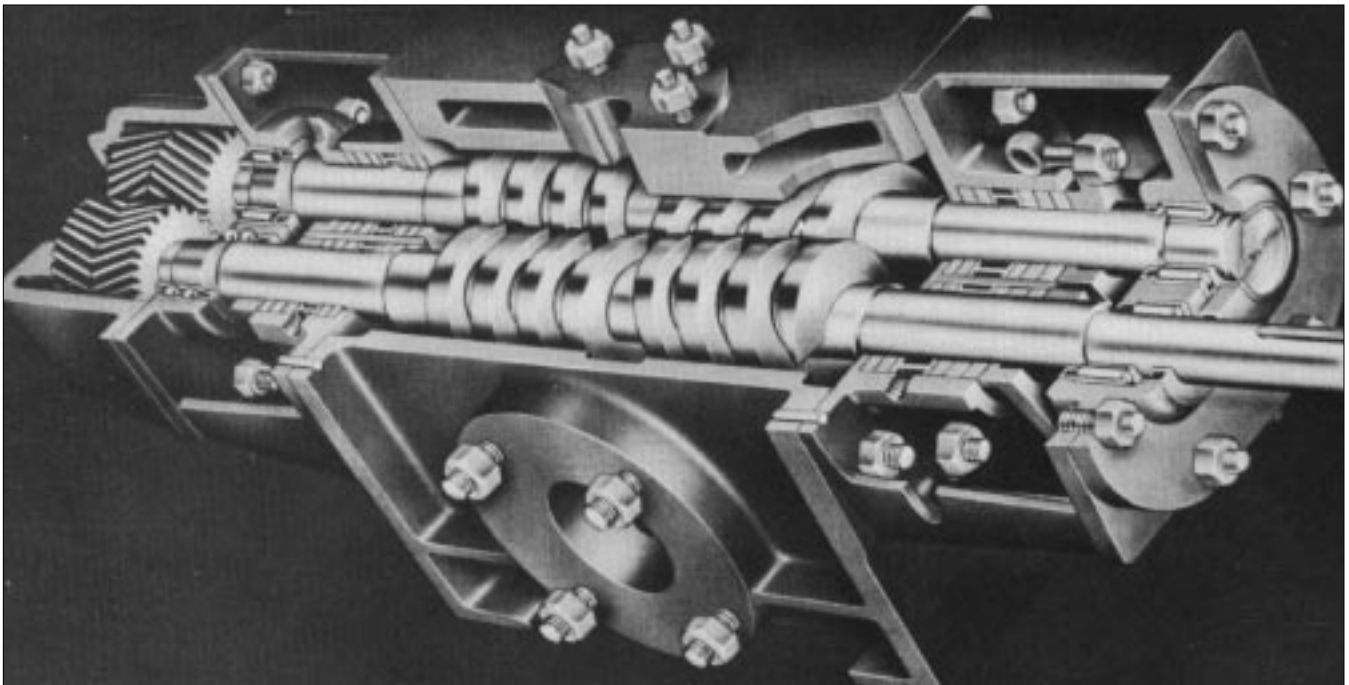**Figure 36. Fuel system for heavy fuel applications**

GT243530

Figure 37. Warren pump

GT24539

Figure 38. Circular flow divider (disassembled)

Figure 39. Flow divider gear pump

Consequently, equal fuel flows to each combustor even though the back-pressure from the fuel nozzles varies.

The bearings in the pump elements are lubricated with the pumped fluid, and some have experienced corrosion. The radial tip clearance between the pump rotors and housings is small, as illustrated by Figure 39. The corrosion caused loss of material from the needle bearings, which allowed the rotors to move into the casing walls causing interference. These deficiencies have

been corrected by the application of corrosion-resistant materials and improved clearance control. Equipment service life on heavy oil fuels is now consistent with the reliability requirement for base-load power generation.

Atomizing Air System

Atomizing air is delivered to each fuel nozzle to finely atomize the fuel for complete, smoke-free combustion. The atomizing air system supplies air at a pressure higher than that in the combustor. The pressure drop across the fuel nozzle sweeps the fuel into the air stream in a finely atomized spray pattern. The major equipment are the compressor and precooler. A typical system is shown in Figure 40.

Atomizing Air Compressor

The atomizing air compressor boosts the pressure of air received from the gas turbine compressor discharge. It is a shaft driven centrifugal compressor mounted on the accessory gear box. The compressor is available with either low- or high-pressure-ratio impellers and diffusers. The pressure ratio of the low-pressure system is 1.4 and is used with distillate fuels. The high-pressure system pressure ratio is 1.7 and is employed with residuals and heavy crudes.

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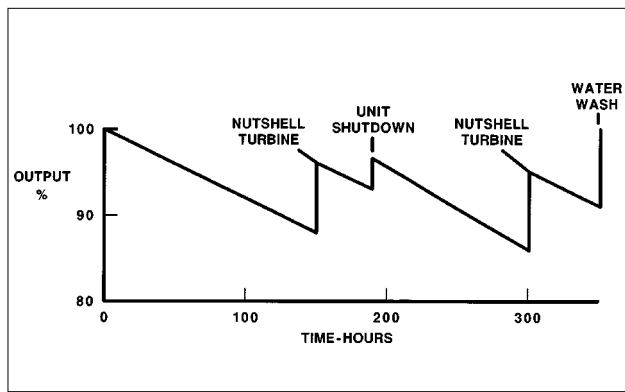
GT24532

Figure 40. Atomizing air system schematic

Precooler

The precooler reduces the temperature of the air upstream of the atomizing air compressor inlet. The air is cooled to reduce compressor power and to cool the fuel nozzle to prevent deposits in the nozzles.

Starting Air Compressor

The main, shaft-driven atomizing air compressor flow is supplemented during turbine start-up by a motor driven air compressor. This compressor is a fixed-displacement lobe-type. It supplies atomizing air at a pressure ratio of 1.3 for ignition and smoke-free operation to approximately 60 percent turbine speed.

Deposit Removal Systems

Turbine cleaning systems are included with heavy fuel fired gas turbines to remove ash deposits from the combustors and turbine gas path parts. Water washing systems remove deposits from the turbine and combustors by the spray-soak-refire method. Water is sprayed into the combustors and turbine through the atomizing air manifold and nozzles while the unit is operated on the starting motor, and allowed to soak into the deposits. The unit is refired and the water absorbed by the deposits forms steam with sufficient pressure to remove deposits. Compressor discharge can be monitored to determine that the turbine is clean. The unit can also be inspected with a borescope to assure that is is cleaned.

The turbine can be partially cleaned during operation under load by the injection of an abrasive compound such as nutshells into the combustion system. Abrasive cleaning removes sufficient deposits to restore 10 to 50 percent of performance loss. This procedure can significantly increase the operating time between shutdowns

for water washing. This improves the economics of burning heavy oils with high deposit rates.

The gas turbine air compressor should be maintained in a clean condition for sustained optimum performance. Therefore, washing the compressor is conducted when the turbine is washed.

Turbine and Compressor Washing System

The turbine and compressor washing system consists of a water-wash skid, on-base piping including water-wash manifold and drains, and skid-to-turbine base interconnecting piping. A 5,500 gallon (21,000 liter) tank holds sufficient water to clean both the compressor and the turbine, and a 50 gallon (190 liter) detergent tank is used for compressor washing. A 250 gpm (16 lps) pump on the skid delivers water to the turbine atomizing air manifold for turbine cleaning. The skid mounted pump is also used to deliver the water/detergent solution and rinse water to the compressor cleaning nozzles located in the air intake. The compressor is washed simultaneously with the turbine.

Turbine Abrasive Cleaning

The abrasive injection system consists of skid-mounted hopper, injection nozzle in each combustor, and interconnecting piping between the skid and unit. Air from the atomizing air system carries the nut shells from the skid mounted hopper to the combustor. Cleaning is performed by connecting the system to the unit, filling and closing the hopper, and opening the valves in the atomizing air line.

Fuel Treatment System

Heavy fuels are frequently contaminated with trace metals and usually require both treatment to remove sodium and potassium and injection of additives to inhibit corrosion. Residuals and heavy crudes require washing to remove the sodium and potassium salts. Some light crudes can be desalted to satisfactory contaminant levels by dehydrating with a centrifuge system.

Residual and Heavy Crude System

The heavy fuel treatment system is typically composed of raw fuel storage tanks, fuel wash unit, effluent water treatment unit, inhibition unit, wash fuel storage tanks, heavy fuel forwarding skid, distillate storage tanks, distillate forwarding skid, and a fuel filter/selection skid. These components are schematically shown in Figure 41.

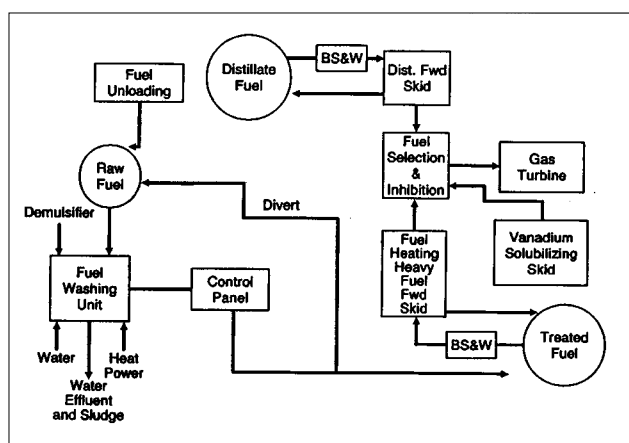The fuel may be contaminated with water, dirt

Figure 41. Heavy-fuel treatment system–with batch-type inhibition

and rust. Tank design should enhance settling. Floating suctions help to avoid the pumping of fuel from the tank bottoms which may contain concentrated contaminants. To reduce contaminant entrainment, the operator should fill tanks and allow time for contaminants to settle before using the stored fuel. Water should be periodically drained to prevent buildup of microorganisms at the fuel/water interface.

Fuel treatment is accomplished in three stages:
- Washing the fuel to remove the water-soluble trace metals such as sodium, potassium, and certain calcium compounds. Washing also removes much of the particulate material prior to forwarding to the filtering systems.
- Inhibiting the vanadium in the fuel with suitable additives.
- Filtration to remove particle contaminants.

Fuel Washing

The primary function of the fuel washing equipment is to remove the water-soluble trace metals and a significant amount of the solid material contained in the fuel. Fuel washing is accomplished by mixing 2 to 10 percent of potable water to absorb the salts, followed by a one- or two-stage water extraction system. A typical system is illustrated in Figure 42. Each stage includes a mixer prior to the centrifuge or electrostatic precipitator. This equipment extracts the salt water from the fuel. The number of water extraction stages depends on the sodium concentration in the fuel and certain fuel properties such as specific gravity and viscosity. Washing systems with one or two stages can consistently reduce sodium and potassium contamination to 1 ppm or less if properly matched for the fuel properties.
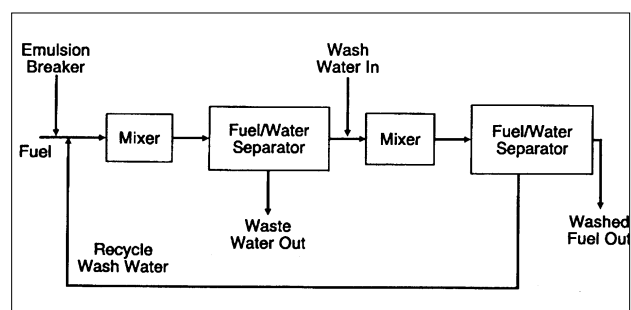
Figure 42. Elements of a two-stage fuel wash system

- Centrifuge Desalting System
  A centrifuge desalting system is normally composed of a centrifuge, water skid, and demulsification skid. The centrifuge system is illustrated in Figure 43. Performance of centrifuge systems is excellent. A typical two-stage system can reduce sodium from 150 ppm to less than 1 ppm for heavy salts. Centrifuges also have excellent capability for removing solids.
- Electrostatic Desalting System
  The electrostatic process is similar to centrifuging. The primary feature of the electrostatic system is that the water is coalesced to large droplets to enhance settling. For example, a 100 to 1 diameter increase in water droplet diameter in turn increases the settling rate by 10,000 to 1 according to Stokes Law. Electrostatic systems require longer start-ups and more filtration than centrifugal systems. They are also less adaptable to fuels of varying quality.

Light Crude Oil Dehydration/Clarification System

The relatively low viscosity and specific gravity of some light crude oils enables removal of small amounts of water by direct centrifuging. In the case of light crude oils, it is possible to reduce the sodium plus potassium to less than 3 ppm by simple centrifuge dehydration. This method also provides the desirable benefit of dirt removal, referred to as clarification. This process is attractive for the Middle East crude oil burning applications where the availability of water is low. A small amount of water, less than 0.1 percent of the oil flow, is used for sealing.

Inhibition

Heavy oils usually contain organic vanadium compounds which cannot be mechanically separated from the fuel. Additives are injected to
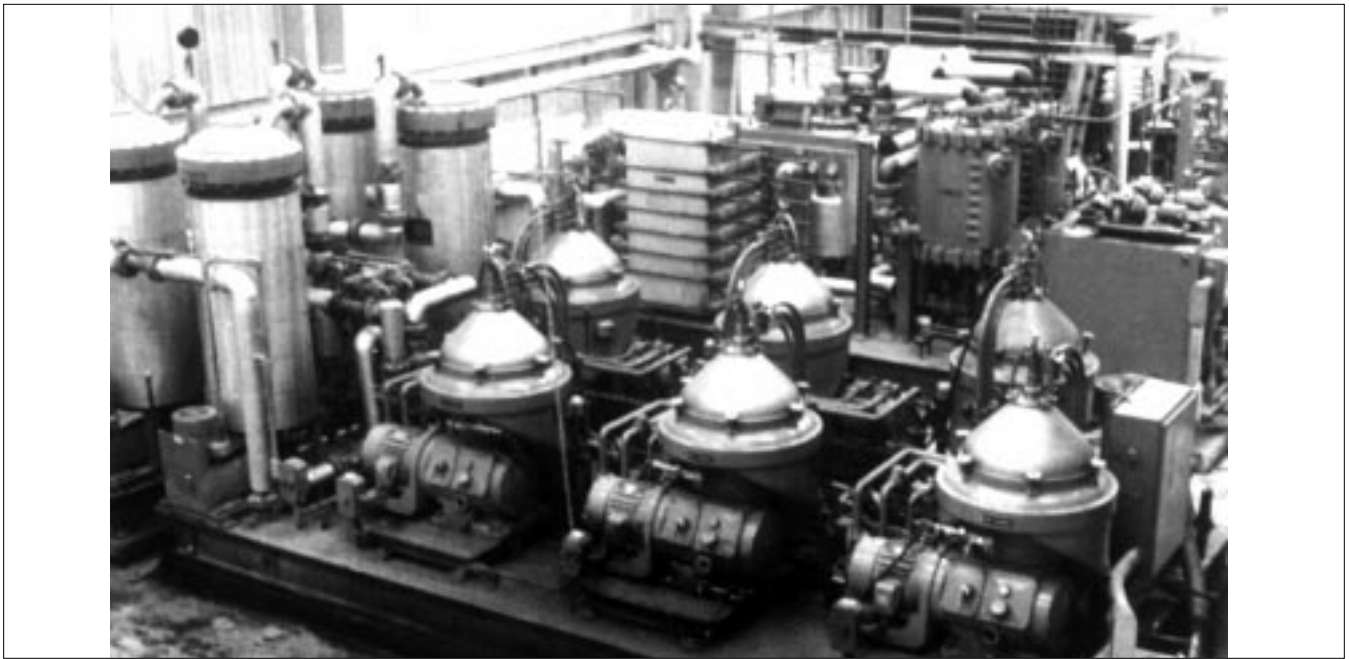
Figure 43. Typical centrifuge installation

inhibit corrosion induced by this contaminant. Inhibitors may also be used to counteract sodium and to modify ash deposits. Two systems are applied for inhibition injection. These are the on-line system and batch processing systems.

The on-line system is illustrated by Figure 44. This system injects the additive in the fuel as it is delivered to the gas turbine. Most heavy fuel fired installations use this system. It allows the use of either oil soluble or less costly water soluble additives.

The batch-type system, sometimes called the total certification system, inhibits fuel as it is delivered to the treated fuel storage tanks. This system requires the use of oil soluble additives that remain in solution during storage and subsequent handling. The advantage of this system is the ability to check the fuel for proper treatment prior to delivery to the gas turbine. Figure 41 incorporates a batch-type system for inhibition.

Fuel Forwarding, Heating and Filtration

The fuel forwarding, heating and filtration system delivers fuel from the storage tank to the gas turbine at the required pressure, temperature, and cleanliness.

Residual and Heavy Crude System

The systems for heavy fuels accommodate the high viscosity and wax content of these fuels. The units start and stop on distillate, and a forwarding system is included for the residual and distillate fuels. A fuel management system includes replaceable-cartridge-type filters and fuel selection valves. This system is illustrated on the residual fuel system schematics, Figure 41.

The residuals and heavy crude oils require heating to approximately 200-275F (93-135C) to maintain the viscosity in a range for proper atomization and to maintain the wax in solution. Heating is usually performed by steam.

Light Crude Oil System

Gas turbines can start and stop on light crude oils, simplifying the forwarding system. When this
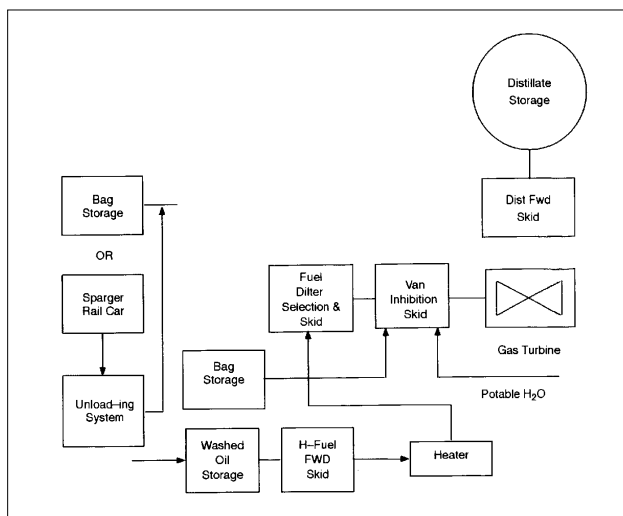
Figure 44. On-line inhibition schematic

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fuel is used, heating is usually not required for pumping, but is required to maintain wax in solution.

OPERATION AND MAINTENANCE REQUIREMENTS

Startup and Shutdown

In order to ensure that the entire turbine liquid fuel system will remain free from any waxy fuel buildups or plugging, startup and shutdown of the gas turbine must occur while burning distillate #2 fuel oil. On startup, the lower viscosity distillate ensures proper light off fuel atomization, and heats up the onbase piping to normal operating temperatures. Fuel transfer to the ash bearing fuel can occur after unit has been synchronized to the grid. The fuel transfer typically requires a gradual 5 minute transfer time. This transfer time allows for the onbase piping and hardware to slowly heat up to the supply temperature of the ash bearing fuel, (which in some instances can approach 275F (135C)), thus ensuring that no frozen blocks of ash bearing fuel form.

On shutdown signal, the unit will automatically unload itself and then transfer to distillate #2 fuel oil. The shutdown must occur on distillate to purge the onbase hardware and make sure that there is no solidification of the ash bearing fuel throughout the fuel system.

Normal Running Operation

During normal operation it will be it will be necessary to periodically remove the ash deposits which form on the first stage nozzle. The rate of deposit buildup on the first stage turbine nozzle is primarily dependent upon the firing temperature of the gas turbine and the amount of vanadium contained in the fuel, (Figure 45). This plot illustrates the effect of firing temperature and vanadium content on the deposition rate. This plot illustrates that the higher the level of vanadium in the fuel, the more pronounced the effect that increasing the firing temperature will have on the rate of deposition. The faster the rate of deposition, the shorter the interval between deposit removal shutdowns. Because of this relationship, the selection of turbine firing temperature should be tailored for each specific site and customer. The benefits of increased output and efficiency must be com-
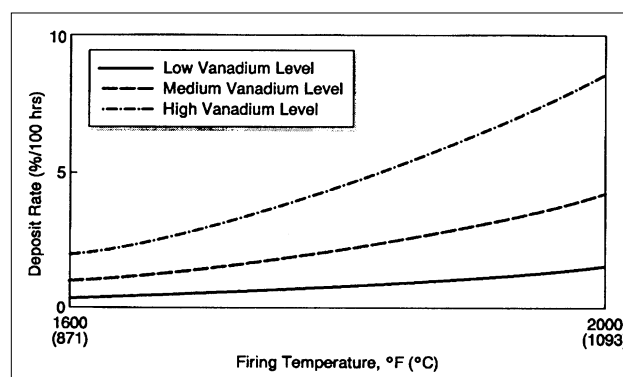
Figure 45. The effect of firing temperature and vanadium content on deposition rate

pared with the costs incurred for deposit removal shutdowns.

The allowable amount of deposit on the first stage nozzle is dependent upon the ambient temperature of the site. The lower the ambient temperature, the higher the mass flow will be through the turbine. For this reason, the amount of first stage nozzle plugging at low ambients will range from 5 - 7 %. At temperatures above 59 F, (15 C), the allowable plugging of the first stage nozzle will be 10 %. Referring back to Figure 45, one can estimate what the turbine water wash interval will be for various levels of vanadium content versus unit firing temperature.

One method used for extending the period between turbine washing is to incorporate a turbine abrasive cleaning system. This type of cleaning can be done online, and restores 10 to 50% of the lost performance through injecting nutshells at the first stage turbine nozzles which removes some of the ash deposits. The effectiveness of the abrasive cleaning cycle on the turbine is dramatically affected by the nature of the deposits. The harder the deposit, the less effective the abrasive cleaning. Since the hardness of the deposit is a direct result of the firing temperature of the gas turbine, a relationship between the two exists such that whenever the rated firing temperature of the unit exceeds 1900F, the effectiveness of abrasive cleaning becomes negligible. But, at lower firing temperatures, a softer deposit forms and abrasive cleaning becomes more effective.

Even when utilizing abrasive cleaning, eventually an offline turbine water wash will be required in order to remove the accumulated deposit. The turbine water washing system for ash bearing fuels will consist of a turbine water wash skid, onbase turbine wash piping, and controls. The procedure for offline turbine water wash, as contained in GE instruction books, is detailed in Table 6.

Table 6
PROCEDURE FOR OFFLINE TURBINE WASH

Procedure	Time
Gas turbine will be shut down and put on crank speed, (540 rpm), to allow wheel-space temperatures to cool to 300 F.	9 hours
With turbine at crank speed, a detergent/water solution for compressor water wash will be injected into the compressor.	5 min.
Unit will be shut down and allowed time to soak.	20 min.
With turbine at crank speed, compressor will be rinsed. At this time copious amounts of water will be injected in the hot gas path via the atomizing air piping, (all combustors at the same time).	20 min.

Based on this procedure, a typical water wash interval for shutdown to start up should be approximately 10 - 12 hours, recognizing that the overall cycle should be adjusted based on the experience of cleaning effectiveness.

To assist the customer in selecting the optimum operating rating for the gas turbine, a plot illustrating the recoverable performance degradation versus time will be developed for each unique application, (Figure 46). This plot illustrates the operating hours for a unit which has nutshelling capability versus a unit which does not. The amount of running hours gained is depicted in "X" hours. In order to better quantify the potential performance degradation due to fouling of the hot gas path, GE estimates an output loss of
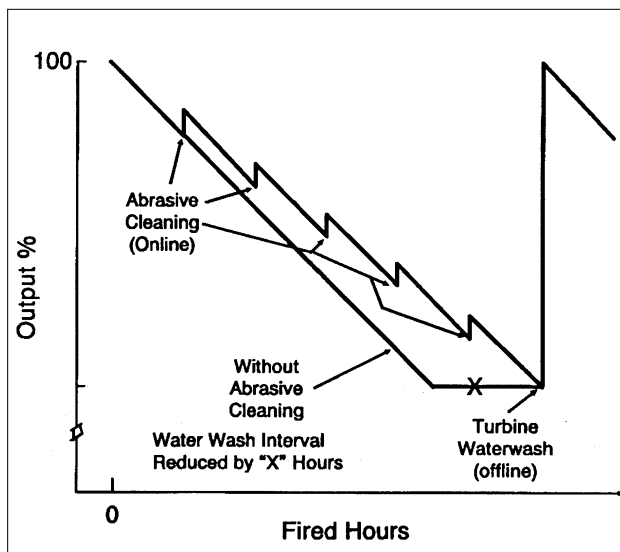
Figure 46. Recoverable performance degradation vs. time
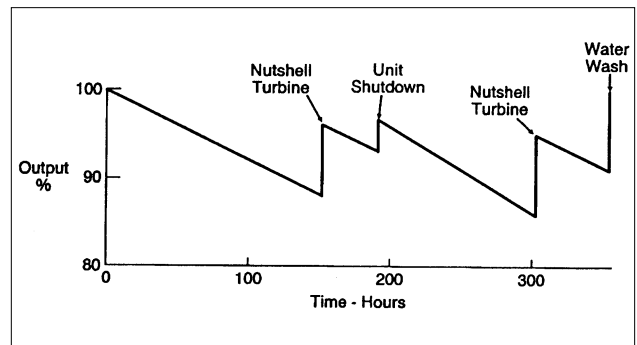
Figure 47. Typical combined cycle performance variation with time – residual oil fuel

approximately 3 % for every 1 % of blockage of the first stage nozzle.

A typical combined cycle performance variation is illustrated in Figure 47. This particular example illustrates the "saw tooth" performance loss that is associated with ash-bearing fuels and water wash/nutshell intervals.

Inspection Intervals

Inspection intervals for optimum turbine service are not fixed for every installation, but rather developed through an interactive process by each user, based on past experience and trends indicated by key turbine factors. The condition of the hot gas path parts provides a good basis for customizing a program of inspections and maintenance. Expected maintenance interval ranges for ash-bearing fuels are identified in Table 7.

The intervals are, in part, based on hydrogen content of the fuels, because heavier hydrocarbon fuels frequently contain corrosive elements and generally release a higher amount of radiant thermal energy. This results in higher combustion system hardware temperatures, which reduces inspection intervals (Figure 48).

GE utilizes a fired hours and/or a fired starts philosophy for determining inspection intervals. This criteria recommends an inspection whenever

Table 7
EXPECTED MAINTENANCE INTERVAL RANGES

Inspection	Hours	Starts
Combustion	3,000	400
Hot Gas Path	6,000 - 12,000	1,200
Major	18,000 - 24,000	2,400
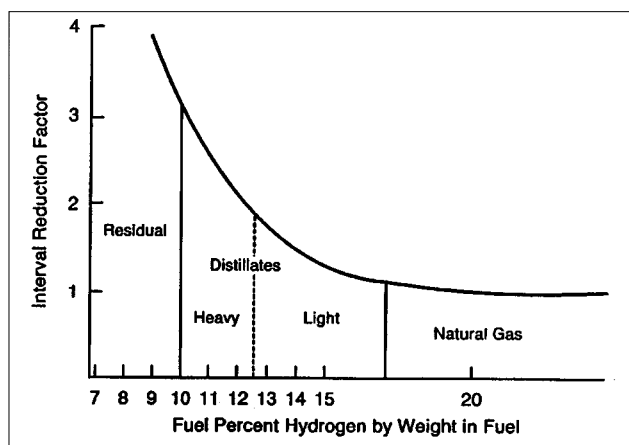
Figure 48. Fuel hydrogen content and
combustion hardware temperatures

the fired hours or starts limit is reached. The limits are based on two different criteria. The fired hour limits are based on corrosion, oxidation, and creep, while the start limits are based on low cycle fatigue of components resulting from thermal cycling of the unit.
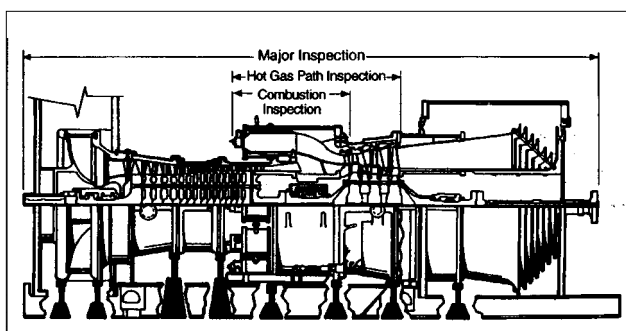
Inspection Scope

The shutdown maintenance inspections include the "combustion", "hot gas path", and "major" inspections. These inspections require disassembly of the turbine in varying degrees. Figure 49 illustrates the turbine sections involved during each of these inspections.

Combustion Inspection

The combustion inspection is a relatively short disassembly inspection which concentrates on the combustion liners, transition pieces, and fuel nozzles, components recognized as being the first to require repair and/or replacement in a good maintenance program.

Hot Gas Path Inspection

The purpose of the hot gas path inspection is

Figure 49. Major inspection work scope

to examine those parts exposed to high temperature from the hot gases discharged from the combustion process. The hot gas path inspection includes the full scope of the combustion inspection, and, in addition, a detailed inspection of the clearances of the turbine nozzles, stationary stator shrouds, and turbine buckets. The hot gas path inspection interval is based on initial recommendation and experience. In addition, the visual borescope evaluation made at the time of the combustion inspection may influence the interval time.

Major Inspection

The purpose of the major inspection is to examine all of the internal rotating and stationary components from the inlet of the machine through the exhaust section of the machine. This inspection includes the elements of the combustion and hot gas path inspections, in addition to laying open the complete flange-to-flange turbine to the horizontal joints (Figure 49). Proper machine centerline support using mechanical jacks and jacking sequence are necessary to assure proper alignment of rotor to stator, obtain accurate half shell clearances, and prevent twisting of the casings while on the half shell.

Inspection Duration

It is difficult to estimate the number of man-hours required for each type of shutdown inspection, primarily because of the wide range of experience, productivity, and working conditions that exist around the world. Based upon the maintenance inspection man-hour assumptions in Figure 50 however, an estimate can be made, as shown in Table 8.

The shutdown inspection man-hours will vary depending upon preplanning, availability of parts,

- Direct Labor - No Supervision
- No Repair Time - Replacement Only
- All Parts Available
- All Necessary Tools Available
- Crew With Average Trade Skills
- Flange-to-Flange Turbine Only
- Inspection Has Been Pre-Planned

Figure 50. Maintenance inspection assumptions

Table 8
TYPICAL ACHIEVED CREW SIZE AND SKILLS COMBUSTION, HOT-GAS-PATH AND MAJOR INSPECTION

Baseload Duty - Gas Fuel - MS7001EA (Gas Turbine Only)

Trade Skill	Manhours		
	Combustion	Hot-Gas-Path	Major
Millwrights	136	2340	4730
Crane Operator	3	68	112
Instr/Elec/NDT Tech	13	36	78
Carpenter	0	48	60
Welder	0	4	12
Pickup/Driver	0	200	300
Total	152	2696	5292
Elapsed Times	(3 X 10 hr Shifts)	17 Days (2 X 10 hr Shift/Day)	22 Days (2 X 10 hr Shift/Day)

site location, productivity, tooling, weather conditions, union regulations, and supervision. Local GE field service personnel are available to help plan the maintenance work that will ultimately reduce downtime and labor costs.

SUMMARY

GE is the world's leading manufacturer of gas turbines utilizing ash-bearing fuels. This paper has presented an overview of unparalleled turbine experience in utility, industrial, and transportation applications. The evolution of gas turbine design, including incorporation of new alloys and coatings, thorough product testing, and monitoring of field experience, has produced durable and reliable machines capable of operating on a wide variety of fuels and at ever-increasing firing temperatures. Internal cooling for hot gas path components has been designed to minimize the effects of ash-bearing fuel deposits. Applications and site specific fuel treatment systems and turbine cleaning regimens allow the gas turbine user maximum fuel flexibility and minimum performance interruption.

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