GE Energy

Heavy-Duty Gas Turbine Operating and Maintenance Considerations

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Introduction

Maintenance costs and availability are two of the most important concerns to a heavy-duty gas turbine equipment owner. Therefore, a well thought out maintenance program that optimizes the owner's costs and maximizes equipment availability should be instituted. For this maintenance program to be effective, owners should develop a general understanding of the relationship between the operating plans and priorities for the plant, the skill level of operating and maintenance personnel, and all equipment manufacturer's recommendations regarding the number and types of inspections, spare parts planning, and other major factors affecting component life and proper operation of the equipment.

In this document, operating and maintenance practices for heavy-duty gas turbines will be reviewed, with emphasis placed on types of inspections plus operating factors that influence maintenance schedules. A well-planned maintenance program will result in maximum equipment availability and optimization of maintenance costs.

Note:

- The operation and maintenance practices outlined in this document are based on full utilization of GE-approved parts, repairs, and services.
- The operating and maintenance discussions presented are generally applicable to all GE heavy-duty gas turbines; i.e., MS3000, 5000, 6000, 7000 and 9000. For purposes of illustration, the MS7001EA was chosen for most components except exhaust systems, which are illustrated using different gas turbine models as indicated. Consult the GE Operation and Maintenance (O&M) Manual for specific questions on a given machine, or contact the local GE Energy representative.

Maintenance Planning

Advanced planning for maintenance is a necessity for utility, industrial, independent power and cogeneration plant operators in order to maximize reliability and availability. The correct implementation of planned maintenance and inspection provides direct benefits in reduced forced outages and increased starting reliability, which in turn can reduce unscheduled repairs and downtime. The primary factors that affect the maintenance planning process are shown in *Figure 1*. The owners' operating mode and practices will determine how each factor is weighted. Parts unique to a gas turbine requiring the most careful attention are those associated with the combustion process, together with those exposed to the hot gases discharged from the combustion system. These are called the combustion section and hot gas path parts, and they include combustion liners, end caps, fuel nozzle assemblies, crossfire tubes, transition pieces, turbine nozzles, turbine stationary shrouds and turbine buckets.

Additional areas for consideration and planning, though longer-term concerns, are the lives of the compressor rotor, turbine rotor, casings and exhaust diffuser. The basic design and recommended maintenance of GE heavy-duty gas turbines are oriented toward:

- Maximum periods of operation between inspections and overhauls
- In-place, on-site inspection and maintenance
- Use of local trade skills to disassemble, inspect and re-assemble gas turbine components

In addition to maintenance of the basic gas turbine, the control devices, fuel-metering equipment, gas turbine auxiliaries, load package, and other station auxiliaries also require periodic servicing. The primary maintenance effort involves five basic systems: controls and accessories, combustion, turbine, generator and balance-of-plant. Controls and accessories are typically serviced in outages of short duration, whereas the other four systems are maintained through less frequent outages of longer duration.

Gas turbine maintenance starts with a clear understanding of the plant operation and the environment in which the plant operates. These two factors should be the basis for developing a maintenance plan for gas turbines.

The inspection and repair requirements, outlined in the O&M Manual provided to each owner, lend themselves to establishing a pattern of inspections. These inspection patterns will vary from site to site and owner operators should understand how factors such as air and fuel quality will be used to develop an inspection and maintenance program. In addition, supplementary information is provided through a system of Technical Information Letters (TILs) associated with

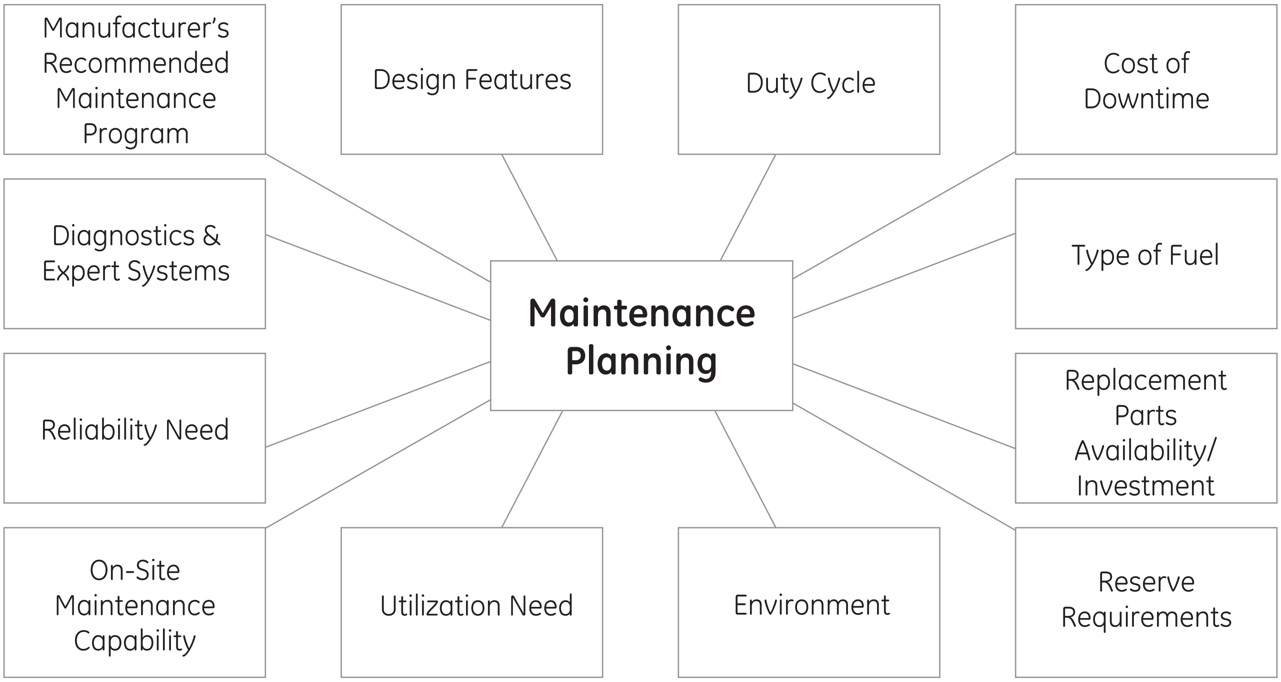

Figure 1. Key factors affecting maintenance planning

specific gas turbines after shipment. This updated information, in addition to the O&M Manual, assures optimum installation, operation and maintenance of the turbine. (See *Figure 2*.) Many of the TILs contain advisory technical recommendations to help resolve issues (as they become known) and to help improve the operation, maintenance, safety, reliability or availability of the turbine. The recommendations contained in TILs should be reviewed and factored into the overall maintenance planning program.

For a maintenance program to be effective, from both cost and turbine availability standpoints, owners must develop a general understanding of the relationship between their operating plans and priorities for the plant and the manufacturer's recommendations regarding the number and types of inspections, spare parts planning, and other major factors affecting the life and proper operation of the equipment. Each of these issues will be discussed in greater detail in the sections that follow.

- **O&M Manual**
  - Turbine-specific manual provided to customer
  - Includes outline of recommended Inspection and Repair requirements
  - Helps customers to establish a pattern of systematic inspections for their site
- **Technical Information Letters (TILs)**
  - Issued after shipment of turbine
  - Provides O&M updates related to turbine installation, maintenance, and operation
  - Provides advisory technical recommendations to help resolve potential issues

Figure 2. Key technical reference documents to include in maintenance planning

Gas Turbine Design Maintenance Features

The GE heavy-duty gas turbine is designed to withstand severe duty and to be maintained on-site, with off-site repair required only on certain combustion components, hot gas path parts and rotor assemblies needing specialized shop service. The following features are designed into GE heavy-duty gas turbines to facilitate on-site maintenance:

- All casings, shells and frames are split on machine horizontal centerline. Upper halves may be lifted individually for access to internal parts.
- With upper-half compressor casings removed, all stationary vanes can be slid circumferentially out of the casings for inspection or replacement without rotor removal.
- With the upper-half of the turbine shell lifted, each half of the first stage nozzle assembly can be removed for inspection, repair or replacement without rotor removal. On some units, upper-half, later-stage nozzle assemblies are lifted with the turbine shell, also allowing inspection and/or removal of the turbine buckets.
- All turbine buckets are moment-weighed and computer charted in sets for rotor spool assembly so that they may be replaced without the need to remove or rebalance the rotor assembly.
- All bearing housings and liners are split on the horizontal centerline so that they may be inspected and replaced when necessary. The lower half of the bearing liner can be removed without removing the rotor.
- All seals and shaft packings are separate from the main bearing housings and casing structures and may be readily removed and replaced.
- On most designs, fuel nozzles, combustion liners and flow sleeves can be removed for inspection, maintenance or replacement without lifting any casings. All major accessories, including filters and coolers, are separate assemblies that are readily accessible for inspection or maintenance. They may also be individually replaced as necessary.
- Casings can be inspected during any outage or any shutdown when the unit enclosure is cool enough for safe entry. The exterior of the inlet, compressor case, compressor discharge case, turbine case, and exhaust frame can be inspected during any outage or period when the enclosure is accessible. The interior surfaces of these cases can be inspected to various degrees depending on the type of outage performed. All interior surfaces can be inspected during a major outage when the rotor has been removed.
- Exhaust diffusers can be inspected during any outage by entering the diffuser through the stack or Heat Recovery Steam Generator (HRSG) access doors. The flow path surfaces, flex seals, and other flow path hardware can be visually inspected with or without the use of a borescope. Diffusers can be weld-repaired without the need to remove the exhaust frame upper half.
- Inlets can be inspected during any outage or shutdown.

Inspection aid provisions have been built into GE heavy-duty gas turbines to facilitate conducting several special inspection procedures. These special procedures provide for the visual inspection and clearance measurement of some of the critical internal components without removal of the casings. These procedures include gas path borescope inspection (BI), radial clearance measurements and turbine nozzle axial clearance measurements.

A GE gas turbine is a fully integrated design consisting of stationary and rotating mechanical, fluid, thermal, and electrical systems. The turbine's performance, as well as the performance of each component within the turbine, is dependent upon the operating interrelationship between internal components and the total operating systems. GE's engineering process evaluates how new designs, design changes or repairs impact components and systems. This design, evaluation, testing, and approval assures the proper balance and interaction between all components and systems for safe, reliable, and economical operation.

Failure to evaluate the full system impact of a new, repaired, or modified part may have negative impacts on the operation and reliability of the entire system. The use of non-GE approved parts, repairs, and maintenance practices may represent a significant risk. Pursuant to the governing terms and conditions, warranties and performance guarantees are predicated upon proper storage, installation, operation, and maintenance, conforming to GE approved operating instruction manuals and repair/modification procedures.

Borescope Inspections

An effective borescope inspection (BI) program can monitor the condition of internal components without the need for casing removal. Borescope inspections should be scheduled with consideration given to the operation and environment of the gas turbine and information from the O&M manual and TILs.

GE heavy-duty gas turbine designs incorporate provisions in both compressor casings and turbine shells for gas path visual inspection of intermediate compressor rotor stages, first, second and third-stage turbine buckets and turbine nozzle partitions by means of the optical borescope. These provisions, consisting of radially aligned holes through the compressor casings, turbine shell and internal stationary turbine shrouds, are designed to allow the penetration of an optical borescope into the compressor or turbine flow path area, as shown in *Figure 3*. Borescope inspection access locations for F Class gas turbines can be found in *Appendix E*.

Figure 4 provides a recommended interval for a planned borescope inspection program following initial base line inspections. It should be recognized that these borescope inspection intervals are based on average unit operating modes. Adjustment of these borescope intervals may be made based on operating experience and the individual unit mode of operation, the fuels used and the results of previous borescope inspections.

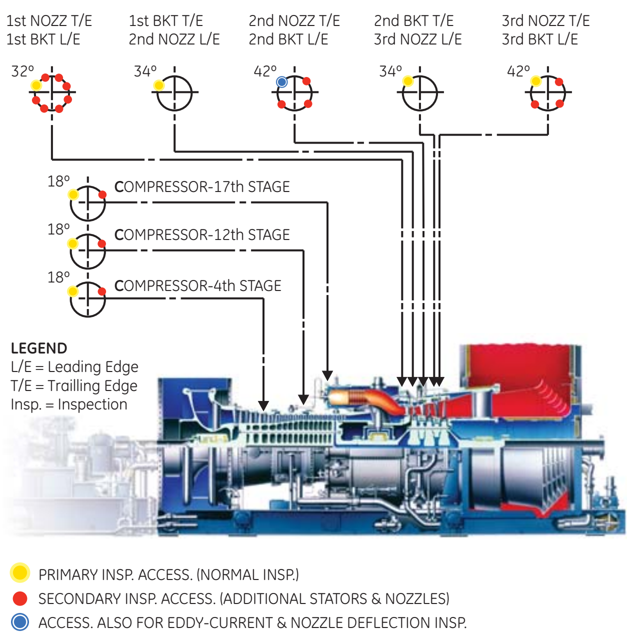

Figure 3. MS7001E gas turbine borescope inspection access locations

In general, an annual or semiannual borescope inspection should use all the available access points to verify the safe and uncompromised condition of the static and rotating hardware. This should include, but is not limited to, signs of excessive gas path fouling, symptoms of surface degradation (such as erosion, corrosion, or spalling), displaced components, deformation or impact damage, material loss, nicks, dents, cracking, indications of contact or rubbing, or other anomalous conditions.

Borescope	Gas and Distillate Fuel Oil	At Combustion Inspection or Annually, Whichever Occurs First
	Heavy Fuel Oil	At Combustion Inspection or Semiannually, Whichever Occurs First

Figure 4. Borescope inspection programming

During BIs and similar inspections, the condition of the upstream components should be verified, including all systems from the filter house to the compressor inlet.

The application of a borescope monitoring program will assist with the scheduling of outages and preplanning of parts requirements, resulting in outage preparedness, lower maintenance costs and higher availability and reliability of the gas turbine.

Major Factors Influencing Maintenance and Equipment Life

There are many factors that can influence equipment life and these must be understood and accounted for in the owner's maintenance planning. As indicated in *Figure 5*, starting cycle (hours per start), power setting, fuel, level of steam or water injection, and site environmental conditions are key factors in determining the maintenance interval requirements as these factors directly influence the life of replaceable gas turbine parts.

Non-consumable components and systems, such as the compressor airfoils, may be affected by such variables as site environmental conditions and plant and accessory system effects. Other factors affecting maintenance planning are shown in *Figure 1*. The plant operator should consider these external factors to prevent the degradation and shortened life of non-consumable components. GE provides supplementary documentation to assist the operator in this regard.

- Cyclic effects
- Firing temperature
- Fuel
- Steam/water injection
- Site environmental conditions

Figure 5. Maintenance cost and equipment life are influenced by key service factors

In the GE approach to maintenance planning, a gas fuel unit operating under continuous duty, with no water or steam injection, is established as the baseline condition, which sets the maximum recommended maintenance intervals. For operation that differs from the baseline, maintenance factors (MF) are established that determine the impact to the component lives and increased frequency of maintenance required. For example, a maintenance factor of two would indicate a maintenance interval that is half of the baseline interval.

Starts and Hours Criteria

Gas turbines wear in different ways for different service-duties, as shown in *Figure 6*. Thermal mechanical fatigue is the dominant limiter of life for peaking machines, while creep, oxidation, and corrosion are the dominant limiters of life for continuous duty machines. Interactions of these mechanisms are considered in the GE design criteria, but to a great extent are second-order effects.

- **Continuous Duty Application**
  - Rupture
  - Creep Deflection
  - High-Cycle Fatigue
  - Corrosion
  - Oxidation
  - Erosion
  - Rubs/Wear
  - Foreign Object Damage
- **Cyclic Duty Application**
  - Thermal Mechanical Fatigue
  - High-Cycle Fatigue
  - Rubs/Wear
  - Foreign Object Damage

Figure 6. Causes of wear – hot gas path components

For that reason, GE bases gas turbine maintenance requirements on independent counts of starts and hours. Whichever criteria limit is first reached determines the maintenance interval. A graphical display of the GE approach is shown in *Figure 7*. In this figure, the inspection interval recommendation is defined by the rectangle established by the starts and hours criteria. These recommendations for inspection fall within the design life expectations and are selected such that components verified to be acceptable for continued use at the inspection point will have low risk of failure during the subsequent operating interval.

An alternative to the GE approach, which is sometimes employed by other manufacturers, converts each start cycle to an equivalent number of operating hours (EOH) with inspection intervals based on the equivalent hours count. For the reasons previously stated, GE does not use this approach. While this logic can create the impression of longer intervals, it actually may result in more frequent maintenance inspections, since separate effects are considered additive. Referring again to *Figure 7*, the starts and hours inspection "rectangle" is reduced in half as defined by the diagonal line from the starts limit at the upper left hand corner to the hours limit at the lower right hand corner. Midrange duty applications, with hours-per-start ratios of 30-50, are particularly penalized by this approach.

This is further illustrated in *Figure 8* for the example of an MS7001EA gas turbine operating on gas fuel, at base load conditions with no steam or water injection or trips from load. The unit operates 4000 hours and 300 starts per year. Following GE's recommendations, the operator would perform the hot gas path inspection after four years of operation, with starts being the limiting condition. Performing maintenance on this same unit based on an equivalent hours criteria would require a hot gas path inspection after 2.4 years. Similarly, for a continuous duty application operating 8000 hours and 160 starts per year, the GE recommendation would be to perform the hot gas path inspection after three years of operation with the operating hours being the limiting condition for this case. The equivalent hours criteria would set the hot gas path inspection after 2.1 years of operation for this application.

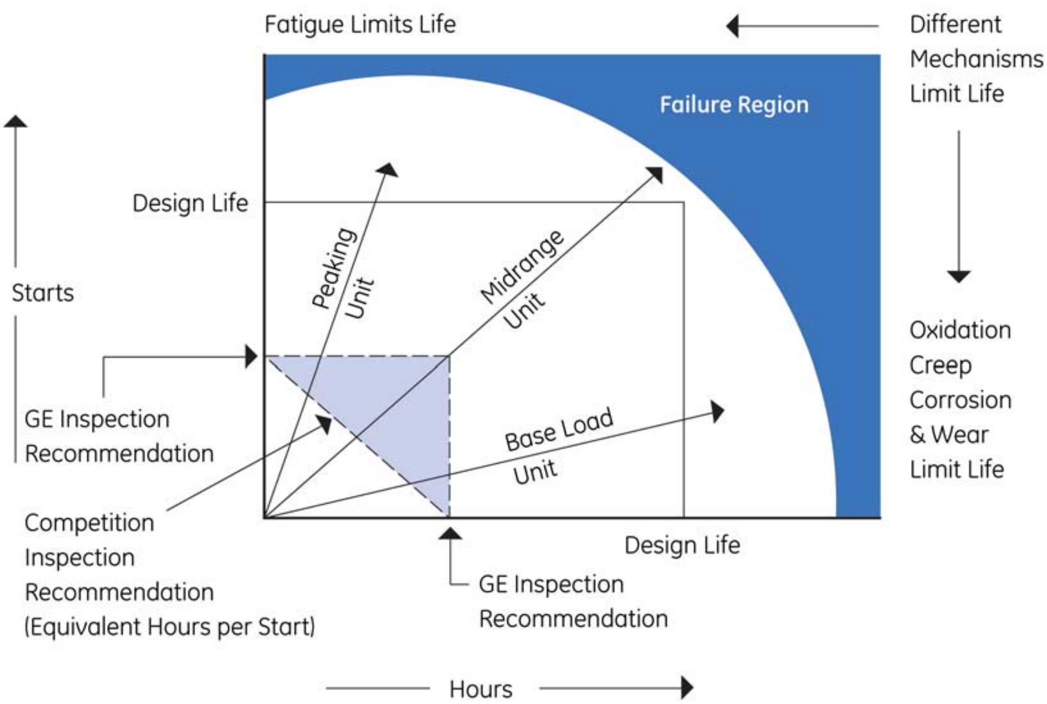

Figure 7. GE bases gas turbine maintenance requirements on independent counts of starts and hours

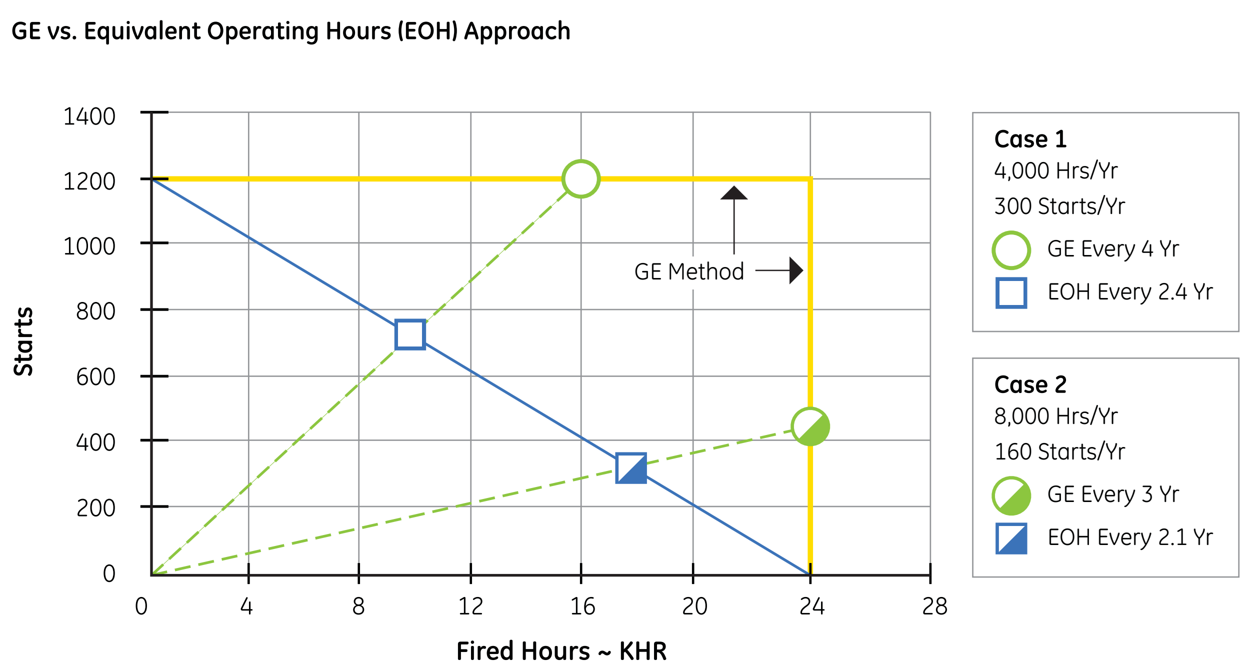

Figure 8. Hot gas path maintenance interval comparisons. GE method vs. EOH method

Service Factors

While GE does not subscribe to the equivalency of starts to hours, there are equivalencies within a wear mechanism that must be considered. As shown in *Figure 9*, influences such as fuel type and quality, firing temperature setting, and the amount of steam or water injection are considered with regard to the hours-based criteria. Startup rate and the number of trips are considered with regard to the starts-based criteria. In both cases, these influences may act to reduce the maintenance intervals.

Typical Max Inspection Intervals (MS6B/MS7EA)

Hot Gas Path Inspection	24,000 hrs or 1200 starts
Major Inspection	48,000 hrs or 2400 starts

Criterion is Hours or Starts (Whichever Occurs First)

Factors Impacting Maintenance

Hours Factors

• Fuel	Gas	1
	Distillate	1.5
	Crude	2 to 3
	Residual	3 to 4
• Peak Load		
• Water/Steam	Injection	
	Dry Control	1 (GTD-222)
	Wet Control	1.9 (5% H_2O GTD-222)

Starts Factors

• Trip from Full Load	8
• Fast Load	2
• Emergency Start	20

Figure 9. Maintenance factors – hot gas path (buckets and nozzles)

When these service or maintenance factors are involved in a unit's operating profile, the hot gas path maintenance "rectangle" that describes the specific maintenance criteria for this operation is reduced from the ideal case, as illustrated in *Figure 10*. The following discussion will take a closer look at the key operating factors and how they can impact maintenance intervals as well as parts refurbishment/replacement intervals.

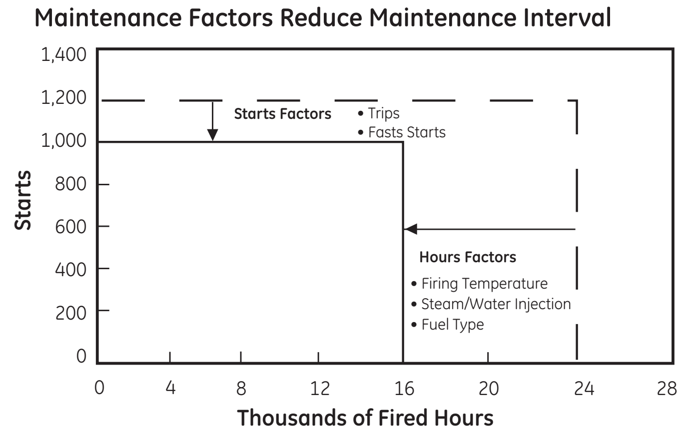

Figure 10. GE maintenance interval for hot gas inspections

Fuel

Fuels burned in gas turbines range from clean natural gas to residual oils and impact maintenance, as illustrated in *Figure 11*. Heavier hydrocarbon fuels have a maintenance factor ranging from three to four for residual fuel and two to three for crude oil

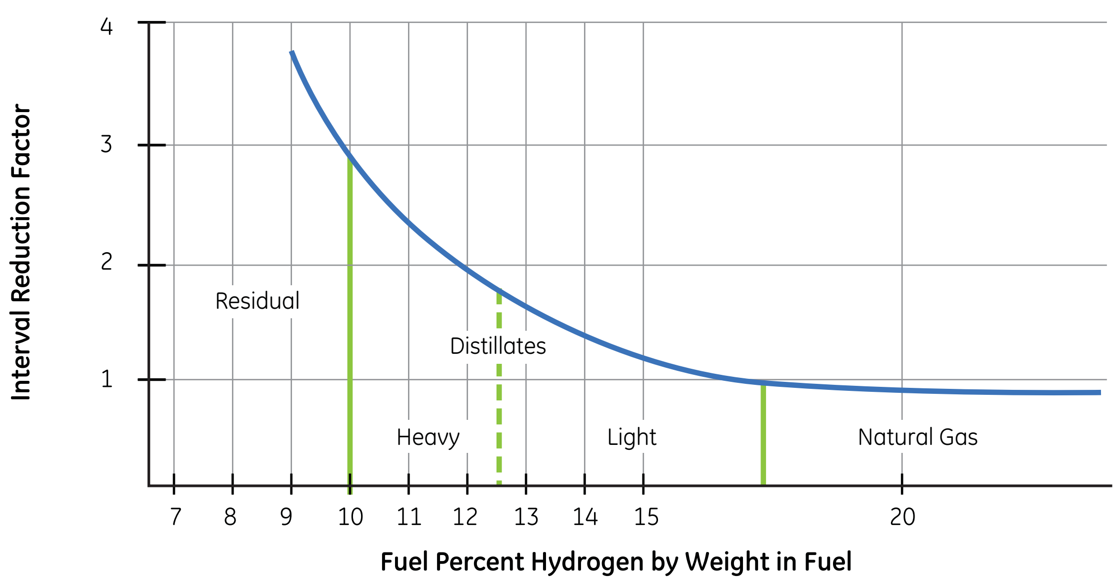

Figure 11. Estimated effect of fuel type on maintenance

fuels (this maintenance factor is to be adjusted based on the water to fuel ratio in cases when water injection for NO_x abatement is used). These fuels generally release a higher amount of radiant thermal energy, which results in a subsequent reduction in combustion hardware life, and frequently contain corrosive elements such as sodium, potassium, vanadium and lead that can cause accelerated hot corrosion of turbine nozzles and buckets. In addition, some elements in these fuels can cause deposits either directly or through compounds formed with inhibitors that are used to prevent corrosion. These deposits impact performance and can lead to a need for more frequent maintenance.

Distillates, as refined, do not generally contain high levels of these corrosive elements, but harmful contaminants can be present in these fuels when delivered to the site. Two common ways of contaminating number two distillate fuel oil are: salt-water ballast mixing with the cargo during sea transport, and contamination of the distillate fuel when transported to site in tankers, tank trucks or pipelines that were previously used to transport contaminated fuel, chemicals or leaded gasoline. From *Figure 11*, it can be seen that GE's experience with distillate fuels indicates that the hot gas path maintenance factor can range from as low as one (equivalent to natural gas) to as high as three. Unless operating experience suggests otherwise, it is recommended that a hot gas path maintenance factor of 1.5 be used for operation on distillate oil. Note also that contaminants in liquid fuels can affect the life of gas turbine auxiliary components such as fuel pumps and flow dividers.

As shown in *Figure 11*, gas fuels that meet GE specifications are considered the optimum fuel with regard to turbine maintenance and are assigned no negative impact. The importance of proper fuel quality has been amplified with Dry Low NO_x (DLN) combustion systems. Proper adherence to GE fuel specifications in GEI-41040 and GEI-41047 is required to allow proper combustion system operation, and to maintain applicable warranties. Liquid hydrocarbon carryover can expose the hot gas path hardware to severe overtemperature conditions and can result in significant reductions in hot gas path parts lives or repair intervals. Liquid hydrocarbon carryover is also responsible for upstream displacement of flame in combustion chambers, which can lead to severe combustion hardware damage. Owners can control this potential issue by using effective gas scrubber systems and by superheating the gaseous fuel prior to use to approximately 50°F (28°C) above the hydrocarbon dew point temperature at the turbine gas control valve connection. For exact superheat requirement calculations please review GEI 41040. Integral to the system, coalescing filters installed upstream of the performance gas heaters is a best practice and ensures the most efficient removal of liquids and vapor phase constituents.

The prevention of hot corrosion of the turbine buckets and nozzles is mainly under the control of the owner. Undetected and untreated, a single shipment of contaminated fuel can cause substantial damage to the gas turbine hot gas path components. Potentially high maintenance costs and loss of availability can be minimized or eliminated by:

- Placing a proper fuel specification on the fuel supplier. For liquid fuels, each shipment should include a report that identifies specific gravity, flash point, viscosity, sulfur content, pour point and ash content of the fuel.
- Providing a regular fuel quality sampling and analysis program. As part of this program, an online water in fuel oil monitor is recommended, as is a portable fuel analyzer that, as a minimum, reads vanadium, lead, sodium, potassium, calcium and magnesium.
- Providing proper maintenance of the fuel treatment system when burning heavier fuel oils and by providing cleanup equipment for distillate fuels when there is a potential for contamination.

In addition to their presence in the fuel, contaminants can also enter the turbine via the inlet air and from the steam or water injected for NO_x emission control or power augmentation. Carryover from evaporative coolers is another source of contaminants. In some cases, these sources of contaminants have been found to cause hot gas path degradation equal to that seen with fuel-related contaminants. GE specifications define limits for maximum concentrations of contaminants for fuel, air and steam/water.

In addition to fuel quality, fuel system operation is also a factor in equipment maintenance. Liquid fuel may remain unpurged and in contact with hot combustion components after shutdown, as well as stagnate in the fuel system when strictly gas fuel is run for an extended time. To minimize varnish and coke accumulation, dual fuel units (gas and liquid capable) should be shutdown running gas fuel whenever possible. Likewise, during extended operation on gas, regular transfers from gas to liquid are recommended to exercise the system components and minimize coking.

Contamination and build-up may prevent the system from removing fuel oil and other liquids from the combustion, compressor discharge, turbine, and exhaust sections when the unit is shut down or during startup. Liquid fuel oil trapped in the system piping also creates a safety risk. Correct functioning of the false start drain system (FSDS) should be ensured through proper maintenance and inspection per GE procedures.

Firing Temperatures

Significant operation at peak load, because of the higher operating temperatures, will require more frequent maintenance and replacement of hot gas path components. *Figure 12* defines the parts life effect corresponding to changes in firing temperature. It should be noted that this is not a linear relationship.

Higher firing temperature reduces hot gas path parts lives while lower firing temperature increases parts lives.

$$\text{E-Class:} \quad A_p = e^{(0.018*\Delta T_f)}$$

$$\text{F-Class:} \quad A_p = e^{(0.023*\Delta T_f)}$$

A_p = Peak fire severity factor
ΔT_f = Peak firing temperature adder (in °F)

Figure 12. Bucket life firing temperature effect

It is important to recognize that a reduction in load does not always mean a reduction in firing temperature. In heat recovery applications, where steam generation drives overall plant efficiency, load is first reduced by closing variable inlet guide vanes to reduce inlet airflow while maintaining maximum exhaust temperature. For these combined cycle applications, firing temperature does not decrease until load is reduced below approximately 80% of rated output. Conversely, a turbine running in simple cycle mode maintains full open inlet guide vanes during a load reduction to 80% and will experience over a 200°F/111°C reduction in firing temperature at this output level. The hot gas path parts life effects for these different modes of operation are obviously quite different. This turbine control effect

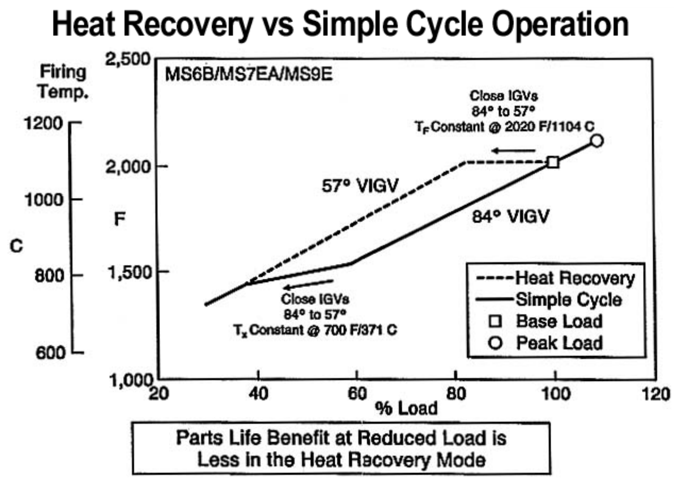

Figure 13. Firing temperature and load relationship – heat recovery vs. simple cycle operation

is illustrated in *Figure 13*. Similarly, turbines with DLN combustion systems utilize inlet guide vane turndown as well as inlet bleed heat to extend operation of low NO_x premix operation to part load conditions.

Firing temperature effects on hot gas path maintenance, as described above, relate to clean burning fuels, such as natural gas and light distillates, where creep rupture of hot gas path components is the primary life limiter and is the mechanism that determines the hot gas path maintenance interval impact. With ash-bearing heavy fuels, corrosion and deposits are the primary influence and a different relationship with firing temperature exists. *Figure 14* illustrates the sensitivity of hot gas path maintenance

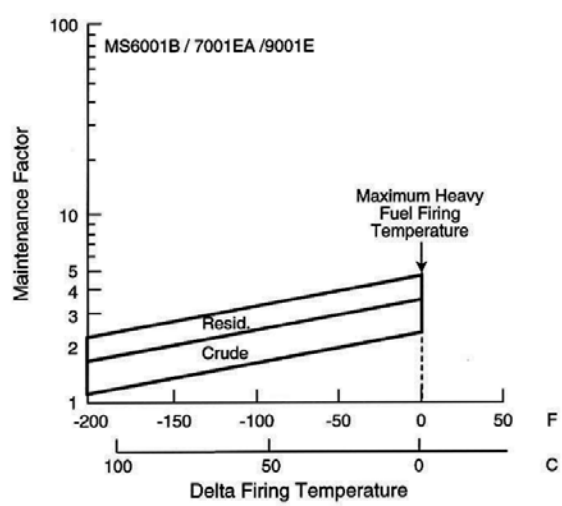

Figure 14. Heavy fuel maintenance factors

factor to firing temperature for a heavy fuel operation. It can be seen that while the sensitivity to firing temperature is less, the maintenance factor itself is higher due to issues relating to the corrosive elements contained in these fuels.

Steam/Water Injection

Water or steam injection for emissions control or power augmentation can impact parts lives and maintenance intervals even when the water or steam meets GE specifications. This relates to the effect of the added water on the hot gas transport properties. Higher gas conductivity, in particular, increases the heat transfer to the buckets and nozzles and can lead to higher metal temperature and reduced parts life as shown in *Figure 15*.

Steam/Water Injection Increases Metal Temperature of Hot-Gas-Path Components

- Water Affects Gas Transport Properties:
  - k - Thermal Conductivity ↑
  - C_P - Specific Heat ↑
  - μ - Viscosity ↔
- This Increases Heat Transfer Coefficients:
- Which Increases Metal Temperature and Decreases Bucket Life

Example (MS7001EA Stage 1 Bucket):
3% Steam (25 ppm NO_x)
H = +4% (Heat Transfer Coefficient)
T_{Metal} = +15 F (8 C)
Life = – 33%

For Constant Firing Temperature

Figure 15. Steam/water injection and bucket/nozzle life

Parts life impact from steam or water injection is directly impacted by the way the turbine is controlled. The control system on most base load applications reduces firing temperature as water or steam is injected. This is known as dry control curve operation, which counters the effect of the higher heat transfer on the gas side, and results in no net impact on bucket life. This is the standard configuration for all gas turbines, both with and without water or steam injection. On some installations, however, the control system is designed to maintain firing temperature constant with water or steam injection level. This is known as wet control curve operation, which results in additional unit output, but decreases parts life as previously described. Units controlled in this way are generally in peaking applications

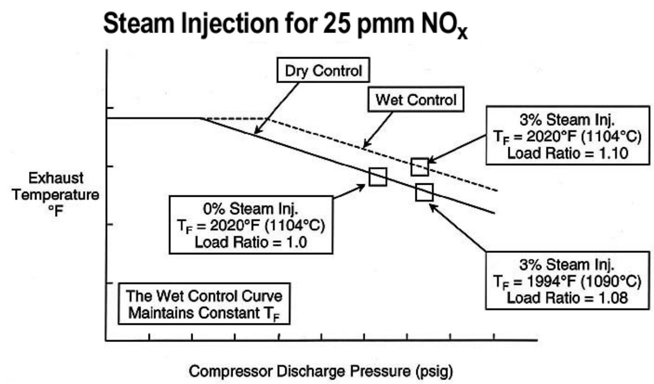

Figure 16. Exhaust temperature control curve – dry vs. wet control MS7001EA

where annual operating hours are low or where operators have determined that reduced parts lives are justified by the power advantage. *Figure 16* illustrates the wet and dry control curve and the performance differences that result from these two different modes of control.

An additional factor associated with water or steam injection relates to the higher aerodynamic loading on the turbine components that results from the injected water increasing the cycle pressure ratio. This additional loading can increase the downstream deflection rate of the second- and third-stage nozzles, which would reduce the repair interval for these components. However, the introduction of GTD-222™ and GTD-241™, high creep strength stage two and three nozzle alloys, has minimized this factor.

Water injection for NO_X abatement should be performed according to the control schedule implemented in the controls system. Forcing operation of the water injection system at high loads can lead to combustion and HGP hardware damage due to thermal shock.

Cyclic Effects

In the previous discussion, operating factors that impact the hours-based maintenance criteria were described. For the starts-based maintenance criteria, operating factors associated with the cyclic effects produced during startup, operation and shutdown of the turbine must be considered. Operating conditions other than the standard startup and shutdown sequence can potentially reduce the cyclic life of the hot gas path components and rotors, and, if present, will require more frequent maintenance and parts refurbishment and/or replacement.

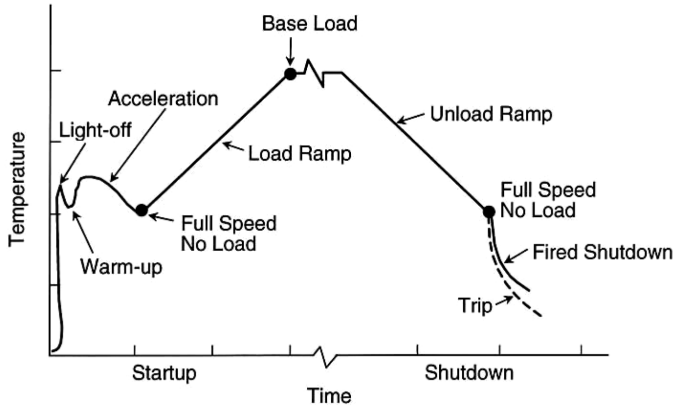

Figure 17. Turbine start/stop cycle – firing temperature changes

Hot Gas Path Parts

Figure 17 illustrates the firing temperature changes occurring over a normal startup and shutdown cycle. Light-off, acceleration, loading, unloading and shutdown all produce gas temperature changes that produce corresponding metal temperature changes. For rapid changes in gas temperature, the edges of the bucket or nozzle respond more quickly than the thicker bulk section, as pictured in *Figure 18*. These gradients, in turn, produce thermal stresses that, when cycled, can eventually lead to cracking. *Figure 19* describes the temperature/strain history of an MS7001EA stage 1 bucket during a normal startup and shutdown cycle. Light-off and acceleration produce transient compressive strains in the bucket as the fast responding leading edge heats up more quickly than the thicker bulk section of the airfoil. At full load conditions, the bucket reaches its maximum metal temperature and a compressive strain is produced from the normal steady state temperature gradients that exist in the cooled part. At shutdown, the conditions reverse and the faster responding edges cool more quickly than the bulk section, which results in a tensile strain at the leading edge.

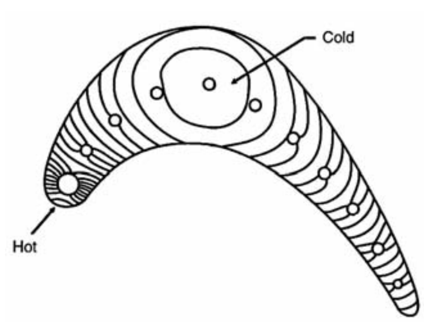

Figure 18. First stage bucket transient temperature distribution

Thermal mechanical fatigue testing has found that the number of cycles that a part can withstand before cracking occurs is strongly influenced by the total strain range and the maximum metal temperature experienced. Any operating condition that significantly increases the strain range and/or the maximum metal temperature over the normal cycle conditions will act to reduce the fatigue life and increase the starts-based maintenance factor. For example, *Figure 20* compares a normal operating cycle with one that includes a trip from full load. The significant increase in the strain range for a trip cycle results in a life effect that equates to eight normal start/stop cycles, as shown. Trips from part load will have a reduced impact because of the lower metal temperatures at the initiation of the trip event. *Figure 21* illustrates that while a trip from between 80% and 100% load has an 8:1 maintenance factor, a trip from full speed no load has a maintenance factor of 2:1. Similarly, overfiring of the unit during peak load operation leads to increased component metal temperatures.

As a result, a trip from peak load has a maintenance factor of 10:1. Trips are to be assessed in addition to the regular startup/shutdown cycles (as starts adders). As such, in the factored starts equation of *Figure 46*, one is subtracted from the severity factor so that the net result of the formula (*Figure 46*) is the same as that dictated by the increased strain range. For example, a startup and trip from base load would count as eight total cycles (one cycle for startup to base load plus 8-1=7 cycles for trip from base load), just as indicated by the 8:1 maintenance factor.

Similarly to trips from load, emergency starts and fast loading will impact the starts-based maintenance interval. This again relates to the increased strain range that is associated with these events.

Emergency starts, in which units are brought from standstill to full load in less than five minutes, will have a parts life effect equal to 20 additional cycles and a normal start with fast loading will have a parts life effect equal to 2 additional cycles. Like trips, the effects of a fast start or fast loading on the machine are considered separate from a normal cycle and their effects must be tabulated in addition to the normal start/stop cycle. However, there is no -1 applied to these factors, so an emergency start to base load would have a total impact of 21 cycles. Refer to *Appendix A* for factored starts examples.

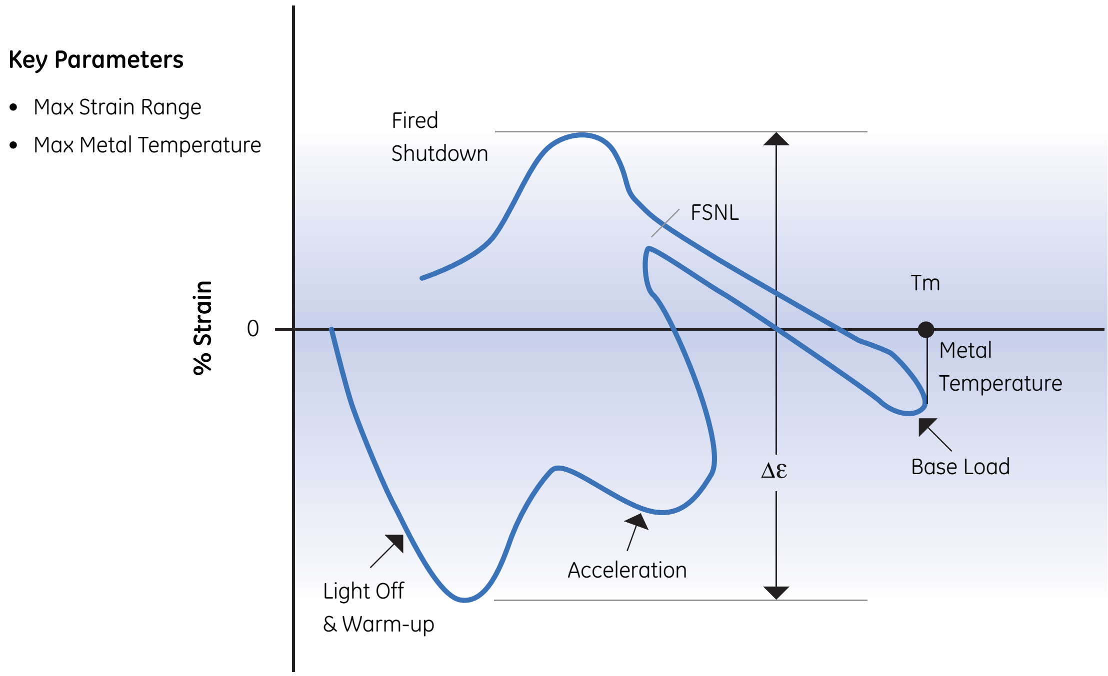

Figure 19. Bucket low cycle fatigue (LCF)

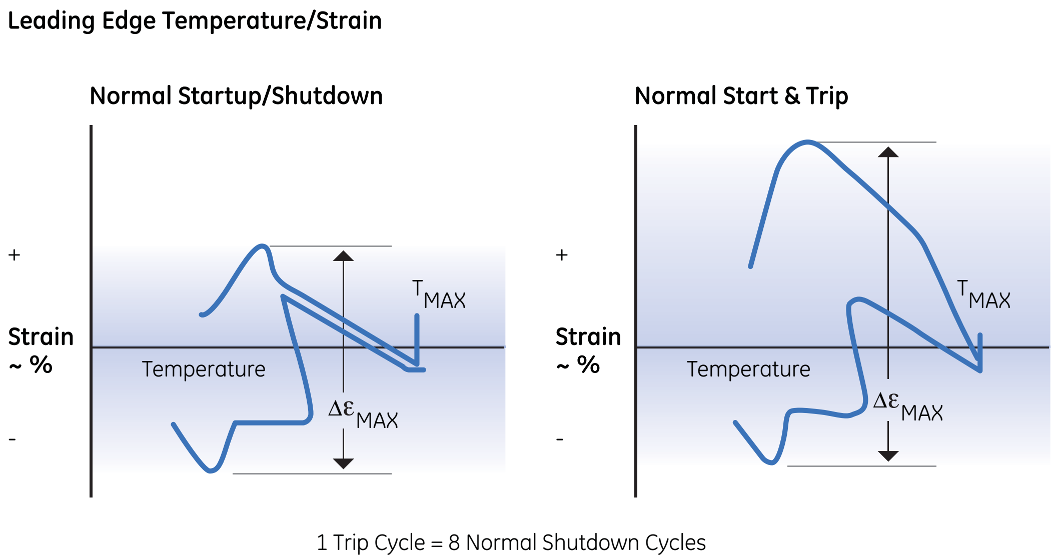

Figure 20. Low cycle fatigue life sensitivities – first stage bucket

While the factors described above will decrease the starts-based maintenance interval, part load operating cycles would allow for an extension of the maintenance interval. *Figure 22* is a guideline that could be used in considering this type of operation. For example, two operating cycles to maximum load levels of less than 60% would equate to one start to a load greater than 60% or, stated another way, would have a maintenance factor of 0.5. Factored starts calculations are based upon the maximum load achieved during operation. Therefore, if a unit is operated at part load for three weeks, and then ramped up to base load for the last ten minutes, then the unit's total operation would be described as a base load start/stop cycle.

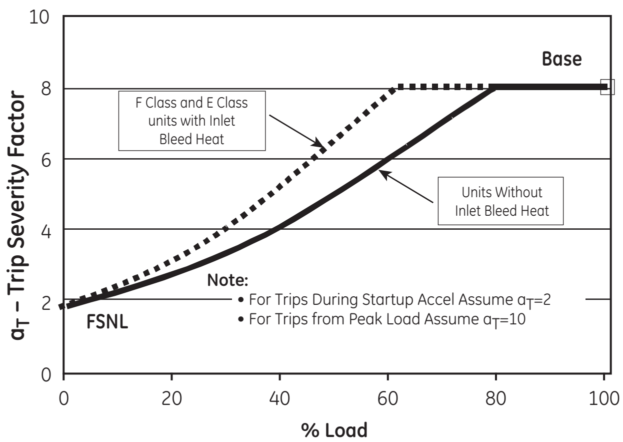

Figure 21. Maintenance factor – trips from load

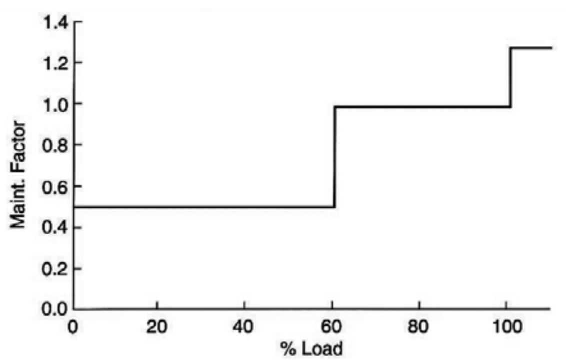

Figure 22. Maintenance factor – effect of start cycle maximum load level

Rotor Parts

In addition to the hot gas path components, the rotor structure maintenance and refurbishment requirements are impacted by the cyclic effects associated with startup, operation and shutdown, as well as loading and off-load characteristics. Maintenance factors specific to an application's operating profile and rotor design must be determined and incorporated into the operators maintenance planning. Disassembly and inspection of all rotor components is required when the accumulated rotor starts or hours reach the inspection limit. (See *Figure 47* and *Figure 48* in the Inspection Intervals Section.)

For the rotor, the thermal condition when the startup sequence is initiated is a major factor in determining the rotor maintenance interval and individual rotor component life. Rotors that are cold when the startup commences develop transient thermal stresses as the turbine is brought on line. Large rotors with their longer thermal time constants develop higher thermal stresses than smaller rotors undergoing the same startup time sequence. High thermal stresses will reduce thermal mechanical fatigue life and the age for inspection.

The steam turbine industry recognized the need to adjust startup times in the 1950 to 1970 time period when power generation market growth led to larger and larger steam turbines operating at higher temperatures. Similar to the steam turbine rotor size increases of the 1950s and 1960s, gas turbine rotors have seen a growth trend in the 1980s and 1990s as the technology has advanced to meet the demand for combined cycle power plants with high power density and thermal efficiency.

With these larger rotors, lessons learned from both the steam turbine experience and the more recent gas turbine experience should be factored into the startup control for the gas turbine and/or maintenance factors should be determined for an application's duty cycle to quantify the rotor life reductions associated with different severity levels. The maintenance factors so determined are used to adjust the rotor component inspection, repair and replacement intervals that are appropriate to that particular duty cycle.

Though the concept of rotor maintenance factors is applicable to all gas turbine rotors, only F Class rotors will be discussed in detail. The rotor maintenance factor for a startup is a function of the downtime following a previous period of operation. As downtime increases, the rotor metal temperature approaches ambient conditions and thermal fatigue impact during a subsequent startup increases. As such, cold starts are assigned a rotor maintenance factor of two, and hot starts a rotor maintenance factor of less than one due to the lower thermal stress under hot conditions. This impact varies from one location in the rotor structure to another. Since the most limiting location determines the overall rotor impact, the rotor maintenance factor indicates the highest rotor maintenance factors at these locations.

Rotor starting thermal condition is not the only operating factor that influences rotor maintenance intervals and component life. Fast starts and fast loading, where the turbine is ramped quickly to load, increase thermal gradients and are more severe duty for the rotor. Trips from load and particularly trips followed by immediate restarts reduce the rotor maintenance interval, as do hot restarts within the first hour of a hot shutdown. *Figure 23* lists recommended operating factors that should be used to determine the rotor's overall maintenance factor for FA and FB design rotors. The factors to be used for other models are determined by applicable Technical Information Letters.

FA/FB* Designs

	Rotor Maintenance Factors	
	Fast Start (FA Only)	Normal Start
Hot Start Factor (1–4 Hrs. Down)	1.0	0.5
Warm 1 Start Factor (4–20 Hrs. Down)	1.8	0.9
Warm 2 Start Factor (20–40 Hrs. Down)	2.8	1.4
Cold Start Factor (>40 Hrs. Down)	4.0	2.0
Trip from Load Factor	4.0	4.0
Hot Start Factor (0–1 Hr. Down)	4.0	2.0

*Other factors may apply to early 9351 units

- Factors Are a Function of Machine Thermal Condition at Startup
- Trips from Load, Fast Starts and >20-hour Restarts Reduce Maintenance Intervals

Figure 23. Operation-related maintenance factors

The significance of each of these factors to the maintenance requirements of the rotor is dependent on the type of operation that the unit sees. There are three general categories of operation that are typical of most gas turbine applications. These are peaking, cyclic and continuous duty as described below:

- Peaking units have a relatively high starting frequency and a low number of hours per start. Operation follows a seasonal demand. Peaking units will generally see a high percentage of warm and cold starts.
- Cyclic duty units start daily with weekend shutdowns. Twelve to sixteen hours per start is typical which results in a warm rotor condition for a large percentage of the starts. Cold starts are generally seen only after a maintenance outage or following a two-day weekend outage.
- Continuous duty applications see a high number of hours per start and most starts are cold because outages are generally maintenance driven. While the percentage of cold starts is high, the total number of starts is low. The rotor maintenance interval on continuous duty units will be determined by service hours rather than starts.

Figure 24 lists operating profiles on the high end of each of these three general categories of gas turbine applications.

As can be seen in *Figure 24*, these duty cycles have different combinations of hot, warm and cold starts with each starting condition having a different impact on rotor maintenance interval as previously discussed. As a result, the starts-based rotor maintenance interval will depend on an application's specific duty cycle. In a later section, a method will be described that allows the turbine operator to determine a maintenance factor that is specific to the operation's duty cycle. The application's integrated maintenance factor uses the rotor maintenance factors described above in combination with the actual duty cycle of a specific application and can be used to determine rotor inspection intervals. In this calculation, the reference duty cycle that yields a starts-based maintenance factor equal to one is defined in *Figure*

Peaking – Cyclic – Continuous

	Peaking	Cyclic	Continuous
Hot Start (Down <4 Hr.)	3%	1%	10%
Warm 1 Start (Down 4-20 hr.)	10%	82%	5%
Warm 2 Start (Down 20-40 Hr.)	37%	13%	5%
Cold Start (Down >40 Hr.)	50%	4%	80%
Hours/Start	4	16	400
Hours/Year	600	4800	8200
Starts per Year	150	300	21
Percent Trips	3%	1%	20%
Number of Trips per Year	5	3	4
Typical Maintenance Factor (Starts Based)	**1.7**	**1.0**	**NA**

- Operational Profile is Application Specific
- Inspection Interval is Application Specific

Figure 24. FA gas turbine typical operational profile

25. Duty cycles different from the *Figure 25* definition, in particular duty cycles with more cold starts, or a high number of trips, will have a maintenance factor greater than one.

Baseline Unit

Cyclic Duty

6	Starts/Week	
16	Hours/Start	
4	Outage/Year Maintenance	
50	Weeks/Year	
4800	Hours/Year	
300	Starts/Year	
0	Trips/Year	
1	Maintenance Factor	
12	Cold Starts/Year (down >40 Hr.)	4%
39	Warm 2 Starts/Year (Down 20-40 Hr.)	13%
246	Warm Starts/Year (Down 4-20 Hr.)	82%
3	Hot Starts per Year	1%

Baseline Unit Achieves Maintenance Factor = 1

Figure 25. Baseline for starts-based maintenance factor definition

Turning gear or ratchet operation after shutdown, and before starting/restarting is a crucial part of normal operating procedure. *Figure F-1* describes turning gear/ratchet scenarios and operation guidelines (*See Appendix*). Relevant operating instructions and TILs should be adhered to where applicable. After a shutdown, turning of the warm rotor is essential to avoid bow, which could lead to high vibrations and excessive rubs if a start is initiated with the rotor in a bowed condition. As a best practice, units should remain on turning gear or ratchet following a planned shutdown until wheelspace temperatures have stabilized at near ambient temperature. If the unit is to see no further activity for 48 hours after cool-down is completed, then it may be taken off of turning gear.

Further guidelines exist for hot restarts and cold starts. It is recommended that the rotor be placed on turning gear for one hour prior to restart following a trip from load, trip from full speed no load, or normal shutdown. This will allow transient thermal stresses to subside before superimposing a startup transient. If the machine must be restarted in less than one hour, a start factor of 2 will apply. Longer periods of turning gear operation may be necessary prior to a cold start or hot restart if the presence of bow is detected. Vibration data taken while at crank speed can be used to confirm that rotor bow is at acceptable levels and the start sequence can be initiated. Users should reference the Operation and Maintenance Manual and appropriate TILs for specific instructions and information for their units.

Combustion Parts

A typical combustion system contains transition pieces, combustion liners, flow sleeves, head-end assemblies containing fuel nozzles and cartridges, end caps and end covers, and assorted other hardware including cross-fire tubes, spark plugs and flame detectors. In addition, there can be various fuel and air delivery components such as purge or check valves and flex hoses. GE provides several types of combustion systems including standard combustors, Multi-Nozzle Quiet Combustors (MNQC), Integrated Gasification Combined Cycle (IGCC) combustors and Dry Low NO_x (DLN) combustors. Each of these combustion systems has unique operating characteristics and modes of operation with differing responses to operational variables affecting maintenance and refurbishment requirements.

Dry Low NO_x (DLN) combustion systems produce lowest NO_x emissions during operation in premixed steady-state combustion mode (PMSS). Continuous and extended operation in lower combustion modes (lean-lean and/or extended lean-lean modes for DLN-1, DLN-1+, DLN 2.0 and sub-piloted premix and/or extended sub-piloted premix, piloted premixed and/or extended piloted premix modes for DLN 2+) is not encouraged due to their impact on combustion hardware life.

Extension of a combustion mode—for example, extended piloted premix—is often attained through manually forcing controls logic in order to maintain the same combustion mode beyond the load where transfer into the next combustion mode would normally occur.

The maintenance and refurbishment requirements of combustion parts are impacted by many of the same factors as hot gas path parts including start cycle, trips, fuel type and quality, firing temperature and use of steam or water injection for either emissions control or power augmentation. However, there are other factors specific to combustion systems. As mentioned above, one of these factors is operating mode, which describes the applied fueling pattern. The use of low combustion modes (as described above) for continuous operation at high turbine loads reduces the maintenance interval significantly, by subsequent increase of the maintenance factor. Examples:

- DLN-1 / DLN-1+ and DLN 2.0 extended lean-lean mode at high loads, which results in a maintenance factor of 10.
- Operation of DLN 2+ combustion systems in extended sub-piloted and extended piloted premixed mode result in a maintenance factor of 10.
- Continuous operation of DLN 2+ in sub-piloted premixed and piloted premixed mode is not recommended as it will drive increased maintenance cost.
- In addition, cyclic operation between piloted premix and premix modes lead to thermal loads on the combustion liner and transition piece similar to the loads encountered during startup/shutdown cycle.

Another factor that can impact combustion system maintenance is acoustic dynamics. Acoustic dynamics are pressure oscillations generated by the combustion system, which, if high enough in magnitude, can lead to significant wear and cracking. GE practice is to tune the combustion system to levels of acoustic dynamics low enough to ensure that the maintenance practices described here are not compromised. In addition, GE encourages monitoring of combustion dynamics during turbine operation throughout the full range of ambient temperatures and loads.

Combustion maintenance is performed, if required, following each combustion inspection (or repair) interval. Inspection interval guidelines are included in *Figure 44*. It is expected, and recommended, that intervals be modified based on specific experience. Replacement intervals are usually defined by a recommended number of combustion (or repair) intervals and are usually combustion component specific. In general, the replacement interval as a function of the number of combustion inspection intervals is reduced if the combustion inspection interval is extended. For example, a component having an 8,000-hour combustion inspection interval (CI), and a six (CI) replacement interval, would have a replacement interval of four (CI) intervals if the inspection interval were increased to 12,000 hours (to maintain a 48,000-hour replacement interval).

For combustion parts, the base line operating conditions that result in a maintenance factor of one are normal fired startup and shutdown to base load on natural gas fuel without steam or water injection. Factors that increase the hours-based maintenance factor include peaking duty, distillate or heavy fuels, and steam or water injection with dry or wet control curves. Factors that increase starts-based maintenance factor include peaking duty, fuel type, steam or water injection, trips, emergency starts and fast loading.

Casing Parts

Most GE gas turbines have inlet, compressor, compressor discharge, and turbine cases in addition to exhaust frames. Inner barrels are typically attached to the compressor discharge case. These cases provide the primary support for the bearings, rotor, and gas path hardware.

The exterior of all casings should be visually inspected for cracking and loose hardware at each combustion, hot gas path, and major outage. The interior of all casings should be inspected whenever possible. The level of the outage determines which casing interiors are accessible for visual inspection. Borescope inspections are recommended for the inlet cases, compressor cases, and compressor discharge cases during gas path borescope inspections. All interior case surfaces should be visibly inspected during a major outage.

Key inspection areas for casings are listed below.

- Bolt holes
- Shroud pin and borescope holes in the turbine shell (case)
- Compressor stator hooks
- Turbine shell shroud hooks
- Compressor discharge case struts
- Inner barrel and inner barrel bolts
- Inlet case bearing surfaces and hooks
- Inlet case and exhaust frame gibs and trunions
- Extraction manifolds (for foreign objects)

Exhaust Diffuser Parts

GE exhaust diffusers come in either axial or radial configurations as shown in *Figures 26* and *27* below. Both types of diffusers are composed of a forward and aft section. Forward diffusers are normally axial diffusers, while aft diffusers can be either axial or radial. Axial diffusers are used in the F-class gas turbines, while radial diffusers are used in B-class and E-class gas turbines.

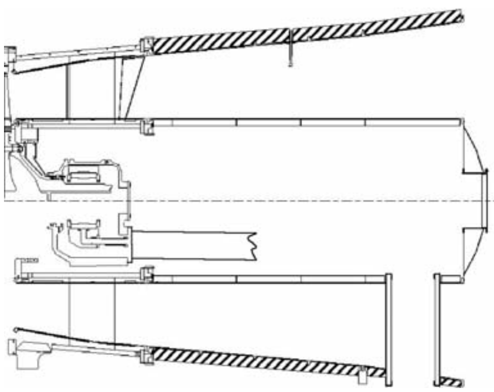

Figure 26. F-Class Axial Diffuser

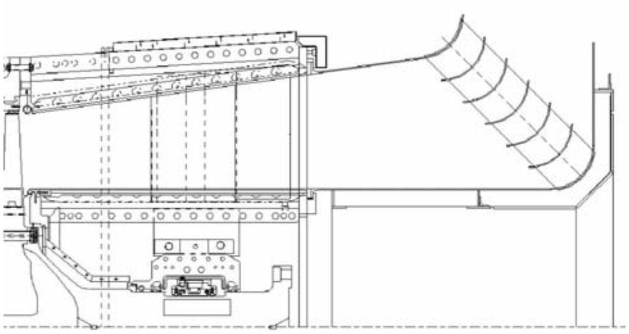

Figure 27. E-Class Radial Diffuser

Exhaust diffusers are subject to high gas path temperatures and vibration due to normal gas turbine operation. Because of the extreme operating environment and cyclic operating nature of gas turbines, exhaust diffusers may develop cracks in the sheet metal surfaces and weld joints used for diffuser construction. Additionally, erosion may occur due to extended operation at high temperatures. Exhaust diffusers should be inspected for cracking and erosion at every combustion, hot gas path and major outage.

In addition to the previously discussed inspections, flex seals, L-seals, and horizontal joint gaskets should be visually inspected for signs of wear or damage at every combustion, hot gas path, and major outage. GE recommends that seals with signs of wear or damage be replaced.

Key areas that should be inspected are listed below. Any damage should be reported to GE for recommended repairs.

- Forward diffuser carrier flange (6FA)
- Airfoil leading and trailing edges
- Turning vanes in radial diffusers (6B, E-class)
- Insulation packs on interior or exterior surfaces
- Clamp ring attachment points to exhaust frame (major outage only)
- Flex seals
- Horizontal joint gaskets

Off-Frequency Operation

GE heavy-duty single shaft gas turbines are designed to operate over a 95% to 105% speed range. Operation at other than rated speed has the potential to impact maintenance requirements. Depending on the industry code requirements, the specifics of the turbine design, and the turbine control philosophy employed, operating conditions can result that will accelerate life consumption of gas turbine components, particularly rotating flowpath hardware. Where this is true, the maintenance factor associated with this operation must be understood and these speed events analyzed and recorded in order to include them in the maintenance plan for the gas turbine.

Generator drive turbines operating in a power system grid are sometimes required to meet operational requirements that are aimed at maintaining grid stability under conditions of sudden load or capacity changes. Most codes require turbines to remain on line in the event of a frequency disturbance. For under-frequency operation, the turbine output decrease that will normally occur with a speed decrease is allowed and the net impact on the turbine as measured by a maintenance factor is minimal. In some grid systems, there are more stringent codes that require remaining on line while maintaining load on a defined schedule of load versus grid frequency. One example of a more stringent requirement is defined by the National Grid Company (NGC). In the NGC code, conditions under which frequency excursions must be tolerated and/or controlled are defined as shown in *Figure 28*.

With this specification, load must be maintained constant over a frequency range of +/- 1% (+/- 0.5Hz in a 50 Hz grid system) with a one percent load reduction allowed for every additional one percent frequency drop down to a minimum 94% speed. Requirements stipulate that operation between 95% to 104% speed can be continuous but operation between 94% and 95% is limited to 20 seconds for each event. These conditions must be met up to a maximum ambient temperature of 25°C (77°F).

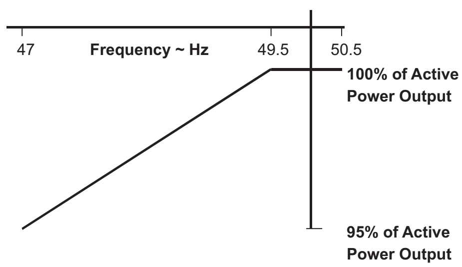

Figure 28. The NGC requirement for output versus frequency capability over all ambients less than 25°C (77°F)

Under-frequency operation impacts maintenance to the degree that nominally controlled turbine output must be exceeded in order to meet the specification defined output requirement. As speed decreases, the compressor airflow decreases, reducing turbine output. If this normal output fall-off with speed results in loads less than the defined minimum, power augmentation must be applied. Turbine overfiring is the most obvious augmentation option but other means, such as gas turbine, water-wash, inlet fogging or evaporative cooling also provide potential means for augmentation.

Ambient temperature can be a significant factor in the level of power augmentation required. This relates to compressor operating margin that may require inlet guide vane closure if compressor corrected speed reaches limiting conditions. For an FA class turbine, operation at 0°C (32°F) would require no power augmentation to meet NGC requirements while operation at 25°C (77°F) would fall below NGC requirements without a substantial amount of power augmentation. As an example, *Figure 29* illustrates the output trend at 25°C (77°F) for an FA class gas turbine as grid system frequency changes and where no power augmentation is applied.

In *Figure 29*, the gas turbine output shortfall at the low frequency end (47.5 Hz) of the NGC continuous operation compliance range would require a 160°F increase over base load firing temperature to be in compliance. At this level of over-fire, a maintenance factor exceeding 100x would be applied to all time spent at these conditions. Overfiring at this level would have implications on combustion operability and emissions compliance as well as have major impact on hot gas path parts life. An alternative power augmentation approach that has been utilized in FA gas turbines for NGC code compliance utilizes water wash in combination with increased firing temperature. As shown in *Figure 30*, with water wash on, 50°F overfiring is required to meet NGC code for operating conditions of 25°C (77°F) ambient temperature and grid frequency at 47.5 Hz. Under these conditions, the hours-based maintenance factor would be 3x as determined by *Figure 12*. It is important to understand that operation at overfrequency conditions will not trade one-for-one for periods at under-frequency conditions. As was discussed in the firing temperature section, above, operation at peak firing conditions has a nonlinear, logarithmic relationship with maintenance factor.

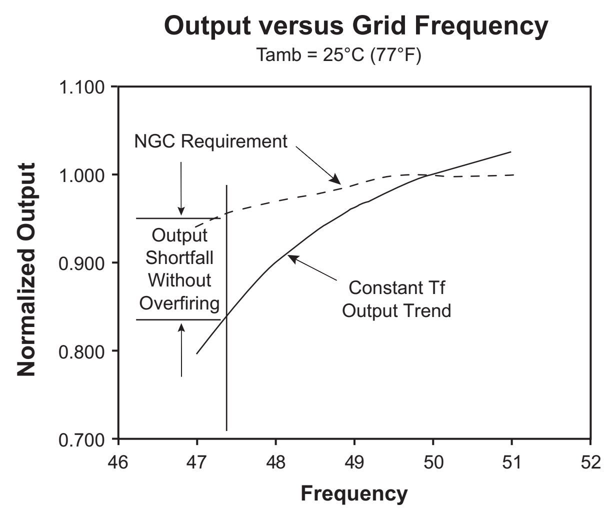

Figure 29. Turbine output at under-frequency conditions

As described above, the NGC code limits operation to 20 seconds per event at an under-frequency condition between 94% to 95% speed. Grid events that expose the gas turbine to frequencies below the minimum continuous speed of 95% introduce additional maintenance and parts replacement considerations. Operation at speeds less than 95% requires increased over-fire to achieve compliance, but also introduces an additional concern that relates to the potential exposure of the blading to excitations that could

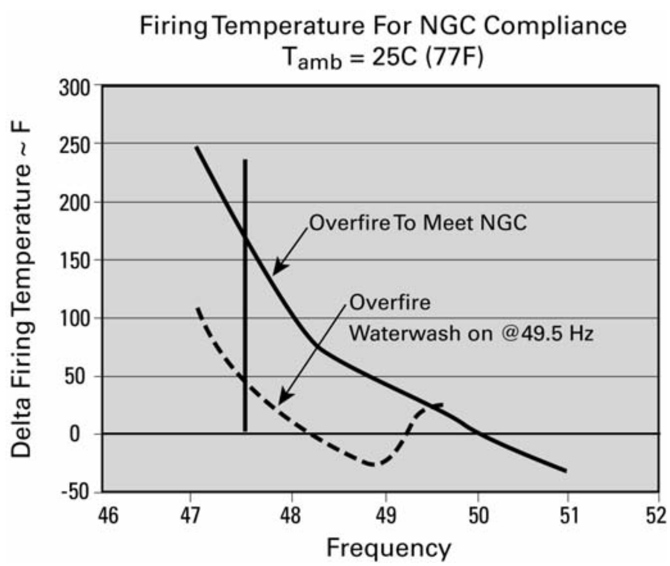

Figure 30. NGC code compliance TF required – FA class

result in blade resonant response and reduced fatigue life. Considering this potential, a starts-based maintenance factor of 60x is assigned to every 20 seconds of excursion for grid frequencies less than 95% speed.

Over-frequency or high speed operation can also introduce conditions that impact turbine maintenance and part replacement intervals. If speed is increased above the nominal rated speed, the rotating components see an increase in mechanical stress proportional to the square of the speed increase. If firing temperature is held constant at the overspeed condition, the life consumption rate of hot gas path rotating components will increase as illustrated in *Figure 31* where one hour of operation at 105% speed is equivalent to two hours at rated speed.

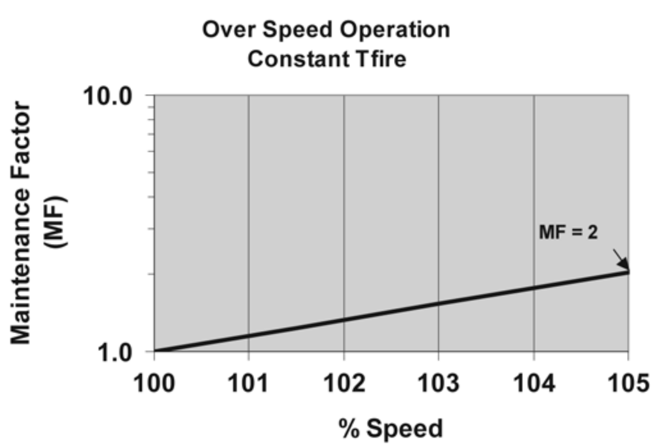

Figure 31. Maintenance factor for overspeed operation ~constant TF

If overspeed operation represents a small fraction of a turbine's operating profile, this effect on parts life can sometimes be ignored. However, if significant operation at overspeed is expected and rated firing temperature is maintained, the accumulated hours must be recorded and included in the calculation of the turbine's overall maintenance factor and the maintenance schedule adjusted to reflect the overspeed operation. An option that mitigates this effect is to under fire to a level that balances the overspeed parts life effect. Some mechanical drive applications have employed that strategy to avoid a maintenance factor increase.

The frequency-sensitive discussion above describes code requirements related to turbine output capability versus grid frequency, where maintenance factors within the continuous operating speed range are hours-based. There are other considerations related to turbines operating in grid frequency regulation mode. In frequency regulation mode, turbines are dispatched to operate at less than full load and stand ready to respond to a frequency disturbance by rapidly picking up load. NGC requirements for units in frequency regulation mode include being equipped with a fast-acting proportional speed governor operating with an overall speed droop of 3-5%. With this control, a gas turbine will provide a load increase that is proportional to the size of the grid frequency change. For example, a turbine operating with five percent droop would pick up 20% load in response to a .5 Hz (1%) grid frequency drop.

The rate at which the turbine picks up load in response to an under-frequency condition is determined by the gas turbine design and the response of the fuel and compressor airflow control systems, but would typically yield a less than ten-second turbine response to a step change in grid frequency. Any maintenance factor associated with this operation depends on the magnitude of the load change that occurs. A turbine dispatched at 50% load that responded to a 2% frequency drop would have parts life and maintenance impact on the hot gas path as well as the rotor structure. More typically, however, turbines are dispatched at closer to rated load where maintenance factor effects may be less severe. The NGC requires 10% plant output in 10 seconds in response to a .5 Hz (1%) under frequency condition. In a combined cycle installation where the gas turbine alone must pick up the transient loading, a load change of 15% in 10 seconds would be required to meet that requirement. Maintenance factor effects related to this would be minimal for the hot gas path but would impact the rotor maintenance factor. For an FA class rotor, each frequency excursion would be counted as an additional factored start in the numerator of the maintenance factor calculation described in *Figure 47*. A further requirement for the rotor is that it must be in hot running condition prior to being dispatched in frequency regulation mode.

Air Quality

Maintenance and operating costs are also influenced by the quality of the air that the turbine consumes. In addition to the deleterious effects of airborne contaminants on hot gas path components, contaminants such as dust, salt and oil can also cause compressor blade erosion, corrosion and fouling. Twenty-micron particles entering the compressor can cause significant blade erosion.

Fouling can be caused by submicron dirt particles entering the compressor as well as from ingestion of oil vapor, smoke, sea salt and industrial vapors. Corrosion of compressor blading causes pitting of the blade surface, which, in addition to increasing the surface roughness, also serves as potential sites for fatigue crack initiation. These surface roughness and blade contour changes will decrease compressor airflow and efficiency, which in turn reduces the gas turbine output and overall thermal efficiency. Generally, axial flow compressor deterioration is the major cause of loss in gas turbine output and efficiency. Recoverable losses, attributable to compressor blade fouling, typically account for 70 to 85 percent of the performance losses seen. As *Figure 32* illustrates, compressor fouling to the extent that airflow is reduced by 5%, will reduce output by 13% and increase heat rate by 5.5%. Fortunately, much can be done through proper operation and maintenance procedures to both minimize fouling type losses and to limit the deposit of corrosive elements. On-line compressor wash systems are available that are used to maintain compressor efficiency by washing the compressor while at load, before significant fouling has occurred. Off-line systems are used to clean heavily fouled compressors. Other procedures include maintaining the inlet filtration system and inlet evaporative coolers as well as periodic inspection and prompt repair of compressor blading.

There are also non-recoverable losses. In the compressor, these are typically caused by nondeposit-related blade surface roughness,

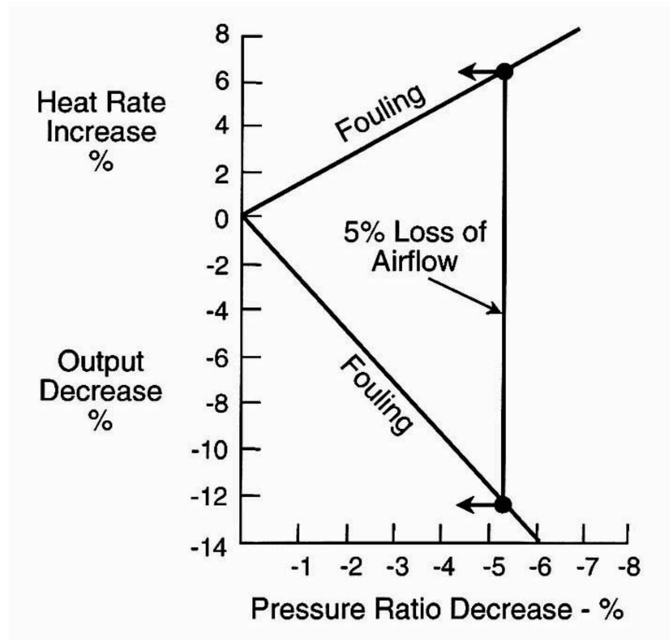

Figure 32. Deterioration of gas turbine performance due to compressor blade fouling

erosion and blade tip rubs. In the turbine, nozzle throat area changes, bucket tip clearance increases and leakages are potential causes. Some degree of unrecoverable performance degradation should be expected, even on a well-maintained gas turbine. The owner, by regularly monitoring and recording unit performance parameters, has a very valuable tool for diagnosing possible compressor deterioration.

Lube Oil Cleanliness

Contaminated or deteriorated lube oil can cause wear and damage on bearing liners. This can lead to extended outages and costly repairs. Routine sampling of the turbine lube oil for proper viscosity, chemical composition and contamination is an essential part of a complete maintenance plan.

Lube oil should be sampled and tested per GEK-32568, "Lubricating Oil Recommendations for Gas Turbines with Bearing Ambients Above 500°F (260°C)." Additionally, lube oil should be checked periodically for particulate and water contamination as outlined in GEK-110483, "Cleanliness Requirements for Power Plant Installation, Commissioning and Maintenance." At a minimum, the lube oil should be sampled on a quarterly basis; however, monthly sampling is recommended.

Moisture Intake

One of the ways some users increase turbine output is through the use of inlet foggers. Foggers inject a large amount of moisture in the inlet ducting, exposing the forward stages of the compressor to potential water carry-over. Operation of a compressor in such an environment may lead to long-term degradation of the compressor due to corrosion and erosion, fouling, and material property degradation. Experience has shown that depending on the quality of water used, the inlet silencer and ducting material, and the condition of the inlet silencer, fouling of the compressor can be severe with inlet foggers. Similarly, carry-over from evaporative coolers and excessive water washing can degrade the compressor. *Figure 33* shows the long-term material property degradation resulting from operating the compressor in a wet environment. The water quality standard that should be adhered to is found in GEK-101944B, "Requirements for Water/Steam Purity in Gas Turbines."

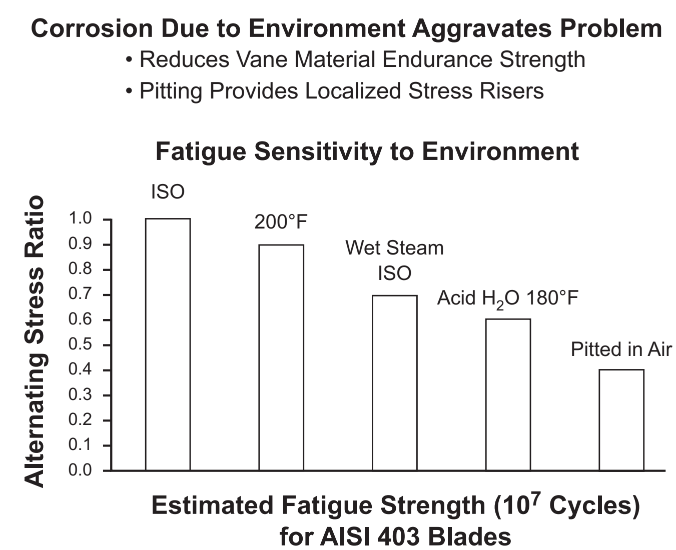

Figure 33. Long-term material property degradation in a wet environment

For turbines with AISI 403 stainless steel compressor blades, the presence of water carry-over will reduce blade fatigue strength by as much as 30% and increases the crack propagation rate in a blade if a flaw is present. The carry-over also subjects the blades to corrosion. Such corrosion might be accelerated by a saline environment (see GER-3419). Further reductions in fatigue strength will result if the environment is acidic and if pitting is present on the blade. Pitting is corrosion-induced and blades with pitting can see material strength reduced to 40% of its original value. This condition is exacerbated by downtime in humid environments, which promotes wet corrosion.

Uncoated GTD-450™ material is relatively resistant to corrosion while uncoated AISI 403 is quite susceptible. Relative susceptibility of various compressor blade materials and coatings is shown in *Figure 34*. As noted in GER-3569F, Al coatings are susceptible to erosion damage leading to unprotected sections of the blade. Because of this, the GECC-1™ coating was created to combine the effects of an aluminum-based (Al) coating to prevent corrosion and a ceramic topcoat to prevent erosion. Water droplets will cause leading edge erosion on the first few stages of the compressor. This erosion, if sufficiently developed, may lead to blade failure. Additionally, the roughened leading edge surface lowers the compressor efficiency and unit performance.

Utilization of inlet fogging or evaporative cooling may also introduce water carry-over or water ingestion into the compressor, resulting in R0 erosion. Although the design intent of evaporative coolers and inlet foggers should be to fully vaporize all cooling water prior to its ingestion into the compressor, evidence suggests that, on systems that were not properly commissioned, the water may not be fully vaporized (e.g., streaking discoloration on the inlet duct or bell mouth). If this is the case, then the unit should be inspected and maintained per instruction, as presented in applicable Technical Information Letters (TILs).

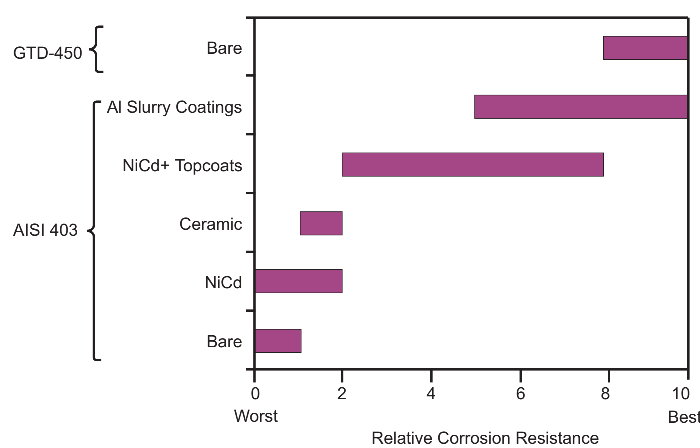

Figure 34. Susceptibility of compressor blade materials and coatings

Maintenance Inspections

Maintenance inspection types may be broadly classified as standby, running and disassembly inspections. The standby inspection is performed during off-peak periods when the unit is not operating and includes routine servicing of accessory systems and device calibration. The running inspection is performed by observing key operating parameters while the turbine is running. The disassembly inspection requires opening the turbine for inspection of internal components and is performed in varying degrees. Disassembly inspections progress from the combustion inspection to the hot gas path inspection to the major inspection as shown in *Figure 35*. Details of each of these inspections are described below.

Standby Inspections

Standby inspections are performed on all gas turbines but pertain particularly to gas turbines used in peaking and intermittent-duty service where starting reliability is of primary concern. This inspection includes routinely servicing the battery system, changing filters, checking oil and water levels, cleaning relays and checking device calibrations. Servicing can be performed in off-peak periods without interrupting the availability of the turbine. A periodic startup test run is an essential part of the standby inspection.

The O&M Manual, as well as the Service Manual Instruction Books, contain information and drawings necessary to perform these periodic checks. Among the most useful drawings in the Service Manual Instruction Books for standby maintenance are the control specifications, piping schematic and electrical elementaries. These drawings provide the calibrations, operating limits, operating characteristics and sequencing of all control devices. This information should be used regularly by operating and maintenance personnel. Careful adherence to minor standby inspection maintenance can have a significant effect on reducing overall maintenance costs and maintaining high turbine reliability. It is essential that a good record be kept of all inspections made and of the maintenance work performed in order to ensure establishing a sound maintenance program.

Running Inspections

Running inspections consist of the general and continued observations made while a unit is operating. This starts by establishing baseline operating data during initial startup of a new unit and after any major disassembly work. This baseline then serves as a reference from which subsequent unit deterioration can be measured.

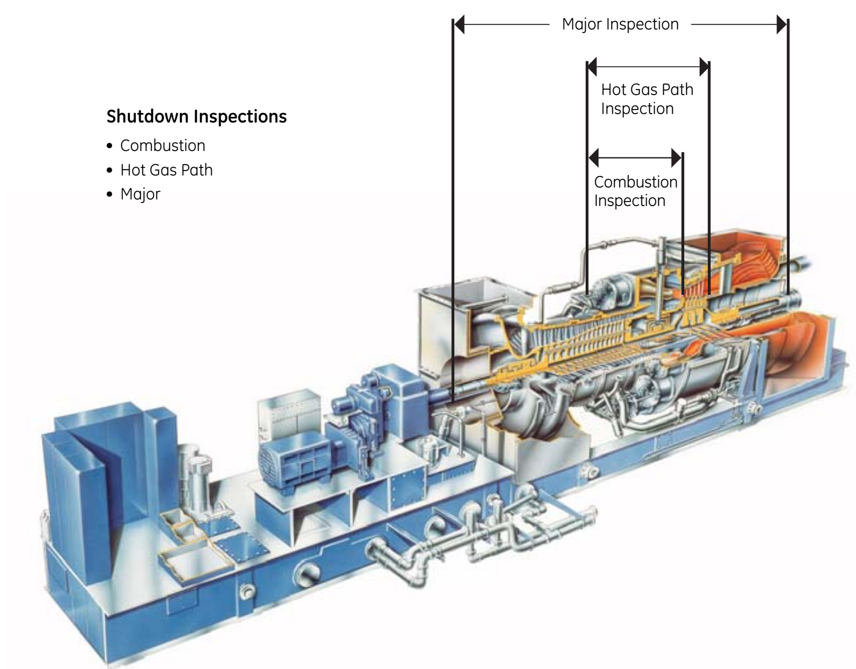

Figure 35. MS7001EA heavy-duty gas turbine – shutdown inspections

Data should be taken to establish normal equipment startup parameters as well as key steady state operating parameters. Steady state is defined as conditions at which no more than a 5°F/3°C change in wheelspace temperature occurs over a 15-minute time period. Data must be taken at regular intervals and should be recorded to permit an evaluation of the turbine performance and maintenance requirements as a function of operating time. This operating inspection data, summarized in *Figure 36,* includes: load versus exhaust temperature, vibration, fuel flow and pressure, bearing metal temperature, lube oil pressure, exhaust gas temperatures, exhaust temperature spread variation and startup time. This list is only a minimum and other parameters should be used as necessary. A graph of these parameters will help provide a basis for judging the conditions of the system. Deviations from the norm help pinpoint impending trouble, changes in calibration or damaged components.

Load vs. Exhaust Temperature

The general relationship between load and exhaust temperature should be observed and compared to previous data. Ambient temperature and barometric pressure will have some effect upon the absolute temperature level. High exhaust temperature can be an indicator of deterioration of internal parts, excessive leaks or a fouled air compressor. For mechanical drive applications, it may also be an indication of increased power required by the driven equipment.

Vibration Level

The vibration signature of the unit should be observed and recorded. Minor changes will occur with changes in operating conditions. However, large changes or a continuously increasing trend give indications of the need to apply corrective action.

Fuel Flow and Pressure

The fuel system should be observed for the general fuel flow versus load relationship. Fuel pressures through the system should be observed. Changes in fuel pressure can indicate the fuel nozzle passages are plugged, or that fuel-metering elements are damaged or out of calibration.

Exhaust Temperature and Spread Variation

The most important control function to be observed is the exhaust temperature fuel override system and the back-up over temperature trip system. Routine verification of the operation and calibration of these functions will minimize wear on the hot gas path parts.

Startup Time

Startup time is an excellent reference against which subsequent operating parameters can be compared and evaluated. A curve of the starting parameters of speed, fuel signal, exhaust temperature and critical sequence bench marks versus time from the initial start signal will provide a good indication of the condition of the

- Speed
- Load
- Fired Starts
- Fired Hours
- Site Barometric Reading
- Temperatures
  - Inlet Ambient
  - Compressor Discharge
  - Turbine Exhaust
  - Turbine Wheelspace
  - Lube Oil Header
  - Lube Oil Tank
  - Bearing Metal
  - Bearing Drains
  - Exhaust Spread

- Pressures
  - Compressor Discharge
  - Lube Pump(s)
  - Bearing Header
  - Cooling Water
  - Fuel
  - Filters (Fuel, Lube, Inlet Air)
- Vibration Data for Power Train
- Generator
  - Output Voltage
  - Phase Current
  - VARS
  - Load
  - Field Voltage
  - Field Current
  - Stator Temp.
  - Vibration
- Startup Time
- Coast-Down Time

Figure 36. Operating inspection data parameters

control system. Deviations from normal conditions help pinpoint impending trouble, changes in calibration or damaged components.

Coast-Down Time

Coast-down time is an excellent indicator of bearing alignment and bearing condition. The time period from when the fuel is shut off on a normal shutdown until the rotor comes to turning gear speed can be compared and evaluated.

Close observation and monitoring of these operating parameters will serve as the basis for effectively planning maintenance work and material requirements needed for subsequent shutdown periods.

Rapid Cool-Down

Prior to an inspection, it may be necessary to force cool the unit to speed the cool-down process and shorten outage time. Force cooling involves turning the unit at crank speed for an extended period of time to continue flowing ambient air through the machine. This is permitted, although a natural cool-down cycle on turning gear or ratchet is preferred for normal shutdowns when no outage is pending.

Forced cooling should be limited since it imposes additional thermal stresses on the unit that may result in a reduction of parts life.

Opening the compartment doors during any cool-down operation is prohibited unless an emergency situation requires immediate compartment inspection—which requires that the doors be opened. Cool-down times should not be accelerated by opening the compartment doors or lagging panels, since uneven cooling of the outer casings may result in excessive case distortion and blade rubs that could potentially lead to tip distress if the rubs are significant.

Combustion Inspection

The combustion inspection is a relatively short disassembly shutdown inspection of fuel nozzles, liners, transition pieces, crossfire tubes and retainers, spark plug assemblies, flame detectors and combustor flow sleeves. This inspection concentrates on the combustion liners, transition pieces, fuel nozzles and end caps which are recognized as being the first to require replacement and repair in a good maintenance program. Proper inspection, maintenance and repair (*Figure 37)* of these items will contribute to a longer life of the downstream parts, such as turbine nozzles and buckets.

Figure 35 illustrates the section of an MS7001EA unit that is disassembled for a combustion inspection. The combustion liners, transition pieces and fuel nozzle assemblies should be removed and replaced with new or repaired components to minimize downtime. The removed liners, transition pieces and fuel nozzles can then be cleaned and repaired after the unit is returned to operation and be available for the next combustion inspection interval. Typical combustion inspection requirements for MS6001B/7001EA/9001E machines are:

- Inspect and identify combustion chamber components.
- Inspect and identify each crossfire tube, retainer and combustion liner.
- Inspect combustion liner for TBC spalling, wear and cracks. Inspect combustion system and discharge casing for debris and foreign objects.
- Inspect flow sleeve welds for cracking.
- Inspect transition piece for wear and cracks.
- Inspect fuel nozzles for plugging at tips, erosion of tip holes and safety lock of tips.
- Inspect all fluid, air, and gas passages in nozzle assembly for plugging, erosion, burning, etc.
- Inspect spark plug assembly for freedom from binding; check condition of electrodes and insulators.
- Replace all consumables and normal wear-and-tear items such as seals, lockplates, nuts, bolts, gaskets, etc.
- Perform visual inspection of first-stage turbine nozzle partitions and borescope inspect (*Figure 3*) turbine buckets to mark the progress of wear and deterioration of these parts. This inspection will help establish the schedule for the hot gas path inspection.
- Perform borescope inspection of compressor.
- Enter the combustion wrapper and observe the condition of blading in the aft end of axial-flow compressor with a borescope.
- Visually inspect the compressor inlet, checking the condition of the IGVs, IGV bushings, and first stage rotating blades.

- Check the condition of IGV actuators and rack-and-pinion gearing.
- Visually inspect compressor discharge case struts for signs of cracking.
- Visually inspect compressor discharge case inner barrel if accessible.
- Visually inspect the last-stage buckets and shrouds.
- Visually inspect the exhaust diffuser for any cracks in flow path surfaces. Inspect insulated surfaces for loose or missing insulation and/or attachment hardware in internal and external locations. In E-class machines, inspect the insulation on the radial diffuser and inside the exhaust plenum as well.
- Inspect exhaust frame flex seals, L-seals, and horizontal joint gaskets for any signs of wear or damage.
- Verify proper operation of purge and check valves. Confirm proper setting and calibration of the combustion controls.

After the combustion inspection is complete and the unit is returned to service, the removed combustion hardware can be inspected by a qualified GE field service representative and, if necessary, sent to a qualified GE Service Center for repairs. The removed fuel nozzles can be cleaned on-site and flow tested on-site, if suitable test facilities are available. For F Class gas turbines it is recommended that repairs and fuel nozzle flow testing be performed at qualified GE Service Centers.

See the O&M manual for additional recommendations and unit specific guidance.

Combustion Inspection

Key Hardware	Inspect For	Potential Action
Combustion liners	Foreign objects	**Repair/refurbish/replace** • Transition Piece – Strip and recoat – Weld repair – Creep repair • Fuel nozzles – Weld repair – Flow test – Leak test • Liners – Strip and recoat – Weld repair – Hula seal replacement – Repair out-of-roundness
Combustion end covers	Abnormal wear	
Fuel nozzles	Cracking	
End caps	Liner cooling hole plugging	
Transition pieces	TBC coating condition	
Cross fire tubes	Oxidation/corrosion/erosion	
Flow sleeves	Hot spots/burning	
Purge valves	Missing hardware	
Check valves	Clearance limits	
Spark plugs	Borescope compressor and turbine	
Flame detectors		
Flex hoses		
Exhaust diffuser	Cracks	Weld repair
Exhaust diffuser Insulation	Loose/missing parts	Replace/tighten parts
Forward diffuser flex seal	Wear/cracked parts	Replace seals
Compressor discharge case	Cracks	Repair or monitoring
Cases – exterior	Cracks	Repair or monitoring

Criteria
- Op. & Instr. Manual
- TILs
- GE Field Engineer

Inspection Methods
- Visual
- Liquid Penetrant
- Borescope

Availability of On-Site Spares is Key to Minimizing Downtime

Figure 37. Combustion inspection – key elements

Hot Gas Path Inspection

The purpose of a hot gas path inspection is to examine those parts exposed to high temperatures from the hot gases discharged from the combustion process. The hot gas path inspection outlined in *Figure 38* includes the full scope of the combustion inspection and, in addition, a detailed inspection of the turbine nozzles, stator shrouds and turbine buckets. To perform this inspection, the top half of the turbine shell must be removed. Prior to shell removal, proper machine centerline support using mechanical jacks is necessary to assure proper alignment of rotor to stator, obtain accurate half-shell clearances and prevent twisting of the stator casings. The MS7001EA jacking procedure is illustrated in *Figure 39*.

Special inspection procedures may apply to specific components in order to ensure that parts meet their intended life. These inspections may include, but are not limited to, dimensional inspections, Fluorescent Penetrant Inspection (FPI), Eddy Current Inspection (ECI) and other forms of non-destructive testing (NDT). The type of inspection required for specific hardware is determined on a part number and operational history basis, and can be obtained from a GE service representative.

Similarly, repair action is taken on the basis of part number, unit operational history, and part condition. Repairs including (but not limited to) strip, chemical clean, HIP (Hot Isostatic Processing), heat treat, and recoat may also be necessary to ensure full parts life. Weld repair will be recommended when necessary, typically as determined by visual inspection and NDT. Failure to perform the required repairs may lead to retirement of the part before its life potential is fulfilled. In contrast, unnecessary repairs are an unneeded expenditure of time and resources. To verify the

Hot Gas Path Inspection

Key Hardware	Inspect For	Potential Action
Nozzles (1, 2, 3) Buckets (1, 2, 3) Stator shrouds IGVs and bushings Compressor blading (borescope)	Foreign object damage Oxidation/corrosion/erosion Cracking Cooling hole plugging Remaining coating life Nozzle deflection/distortion Abnormal deflection/distortion Abnormal wear Missing hardware Clearance limits	Repair/refurbishment/replace • Nozzles – Weld repair – Reposition – Recoat • Buckets – Strip & recoat – Weld repair – Blend – Creep life limit – Top shroud deflection
Exhaust diffuser	Cracks	Weld repair
Exhaust diffuser Insulation	Loose/missing parts	Replace/tighten parts
Forward diffuser flex seal	Wear/cracked parts	Replace seals
Compressor discharge case	Cracks	Repair or monitoring
Turbine shell	Cracks	Repair or monitoring
Cases – exterior	Cracks	Repair or monitoring

Criteria
- Op. & Instr. Manual
- TILs
- GE Field Engineer

Inspection Methods
- Visual
- Liquid Penetrant
- Borescope

Availability of On-Site Spares is Key to Minimizing Downtime

Figure 38. Hot gas path inspection – key elements

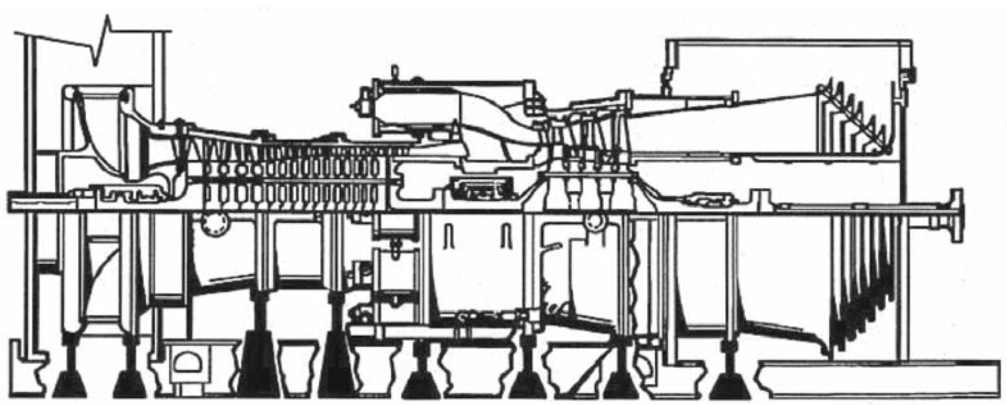

Figure 39. Stator tube jacking procedure – MS7001EA

types of inspection and repair required, contact your service representative prior to an outage.

For inspection of the hot gas path (*Figure 35*), all combustion transition pieces and the first-stage turbine nozzle assemblies must be removed. Removal of the second- and third-stage turbine nozzle segment assemblies is optional, depending upon the results of visual observations, clearance measurements, and other required inspections. The buckets can usually be inspected in place. Fluorescent penetrant inspection (FPI) of the bucket vane sections may be required to detect any cracks. In addition, a complete set of internal turbine radial and axial clearances (opening and closing) must be taken during any hot gas path inspection. Re-assembly must meet clearance diagram requirements to ensure against rubs and to maintain unit performance. Typical hot gas path inspection requirements for all machines are:

- Inspect and record condition of first, second and third-stage buckets. If it is determined that the turbine buckets should be removed, follow bucket removal and condition recording instructions. Buckets with protective coating should be evaluated for remaining coating life.
- Inspect and record condition of first-, second- and third-stage nozzles.
- Inspect and record condition of later-stage nozzle diaphragm packings.
- Check seals for rubs and deterioration of clearance.
- Record the bucket tip clearances.
- Inspect bucket shank seals for clearance, rubs and deterioration.
- Perform inspections on cutter teeth of tip-shrouded buckets. Consider refurbishment of buckets with worn cutter teeth, particularly if concurrently refurbishing the honeycomb of the corresponding stationary shrouds. Consult your GE Energy representative to confirm that the bucket under consideration is repairable.
- Check the turbine stationary shrouds for clearance, cracking, erosion, oxidation, rubbing and build-up.
- Check and replace any faulty wheelspace thermocouples.
- Enter compressor inlet plenum and observe the condition of the forward section of the compressor.
- Visually inspect the compressor inlet, checking the condition of the IGVs, IGV bushings, and first stage rotating blades.
- Check the condition of IGV actuators and rack-and-pinion gearing.
- Enter the combustion wrapper and, with a borescope, observe the condition of the blading in the aft end of the axial flow compressor.
- Visually inspect compressor discharge case struts for signs of cracking.
- Visually inspect compressor discharge case inner barrel if accessible.
- Visually inspect the turbine shell shroud hooks for sign of cracking.

- Visually inspect the exhaust diffuser for any cracks in flow path surfaces. Inspect insulated surfaces for loose or missing insulation and/or attachment hardware in internal and external locations. In E-class machines, inspect the insulation on the radial diffuser and inside the exhaust plenum as well.
- Inspect exhaust frame flex seals, L-seals, and horizontal joint gaskets for any signs of wear or damage.

The first-stage turbine nozzle assembly is exposed to the direct hot gas discharge from the combustion process and is subjected to the highest gas temperatures in the turbine section. Such conditions frequently cause nozzle cracking and oxidation and, in fact, this is expected. The second- and third-stage nozzles are exposed to high gas bending loads, which in combination with the operating temperatures, can lead to downstream deflection and closure of critical axial clearances. To a degree, nozzle distress can be tolerated and criteria have been established for determining when repair is required. These limits are contained in the Operations and Maintenance Manuals previously described. However, as a general rule, first stage nozzles will require repair at the hot gas path inspection. The second- and third-stage nozzles may require refurbishment to re-establish the proper axial clearances. Normally, turbine nozzles can be repaired several times and it is generally repair cost versus replacement cost that dictates the replacement decision.

Coatings play a critical role in protecting the buckets operating at high metal temperatures to ensure that the full capability of the high strength superalloy is maintained and that the bucket rupture life meets design expectations. This is particularly true of cooled bucket designs that operate above 1985°F (1085°C) firing temperature. Significant exposure of the base metal to the environment will accelerate the creep rate and can lead to premature replacement through a combination of increased temperature and stress and a reduction in material strength, as described in *Figure 40*. This degradation process is driven by oxidation of the unprotected base alloy. In the past, on early generation uncooled designs, surface degradation due to corrosion or oxidation was considered to be a performance issue and not a factor in bucket life. This is no longer the case at the higher firing temperatures of current generation designs.

Given the importance of coatings, it must be recognized that even the best coatings available will have a finite life and the condition of the coating will play a major role in determining bucket life. Refurbishment through stripping and recoating is an option for achieving bucket's expected/design life, but if recoating is selected, it should be done before the coating is breached to expose base metal. Normally, for turbines in the MS7001EA class, this means that recoating will be required at the hot gas path inspection. If recoating is not performed at the hot gas path inspection, the life

Oxidation & Bucket Life

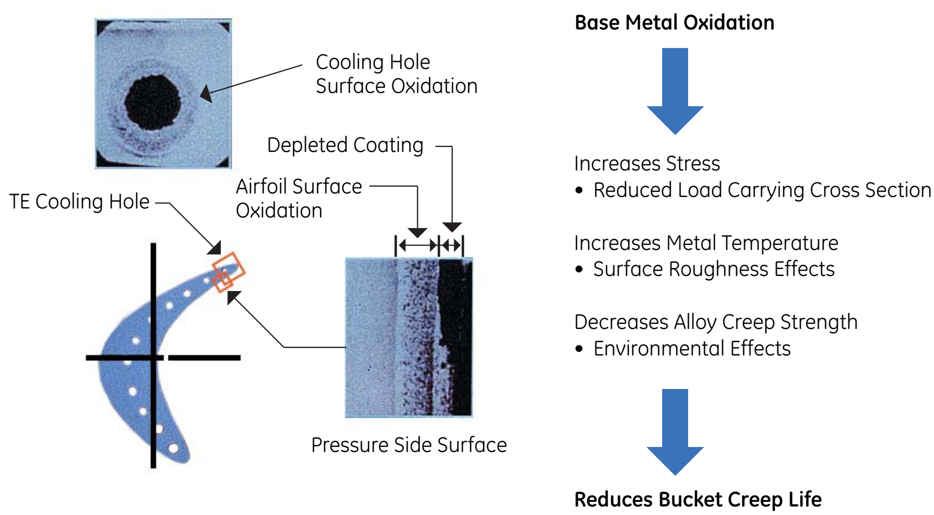

Figure 40. Stage 1 bucket oxidation and bucket life

of the buckets would generally extend to the major inspection, at which point the buckets would be replaced. For F class gas turbines, recoating of the first stage buckets is recommended at each hot gas path inspection. Visual and borescope examination of the hot gas path parts during the combustion inspections as well as nozzle-deflection measurements will allow the operator to monitor distress patterns and progression. This makes part-life predictions more accurate and allows adequate time to plan for replacement or refurbishment at the time of the hot gas path inspection. It is important to recognize that to avoid extending the hot gas path inspection, the necessary spare parts should be on site prior to taking the unit out of service.

See the O&M manual for additional recommendations and unit specific guidance.

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. A major inspection should be scheduled in accordance with the recommendations in the owner's Operations and Maintenance Manual or as modified by the results of previous borescope and hot gas path inspection. The work scope shown in *Figure 41* involves inspection of all of the major flange-to-flange components of the gas turbine, which are subject to deterioration during normal turbine operation. This inspection includes previous elements of the combustion and hot gas path inspections, in addition to laying open the complete flange-to-flange gas turbine to the horizontal joints, as shown in *Figure 42*.

Removal of all of the upper casings allows access to the compressor rotor and stationary compressor blading, as well as to the bearing assemblies. Prior to removing casings, shells and frames, the unit must be properly supported. Proper centerline support using mechanical jacks and jacking sequence procedures are necessary to assure proper alignment of rotor to stator, obtain accurate half shell clearances and to prevent twisting of the casings while on the half shell. Typical major inspection requirements for all machines are:

- All radial and axial clearances are checked against their original values (opening and closing).
- Casings, shells and frames/diffusers are inspected for cracks and erosion.
- Compressor inlet and compressor flow-path are inspected for fouling, erosion, corrosion and leakage.
- Visually inspect the compressor inlet, checking the condition of the IGVs, IGV bushings, and first stage rotating blades.
- Check the condition of IGV actuators and rack-and-pinion gearing.
- Rotor and stator compressor blades are checked for tip clearance, rubs, impact damage, corrosion pitting, bowing and cracking.
- Turbine stationary shrouds are checked for clearance, erosion, rubbing, cracking, and build-up.
- Seals and hook fits of turbine nozzles and diaphragms are inspected for rubs, erosion, fretting or thermal deterioration.
- Turbine buckets are removed and a nondestructive check of buckets and wheel dovetails is performed (first stage bucket protective coating should be evaluated for remaining coating life). Buckets that were not recoated at the hot gas path inspection should be replaced. Wheel dovetail fillets, pressure faces, edges, and intersecting features must be closely examined for conditions of wear, galling, cracking or fretting.
- Rotor inspections recommended in the maintenance and inspection manual or by Technical Information Letters should be performed.
- Bearing liners and seals are inspected for clearance and wear.
- Inlet systems are inspected for corrosion, cracked silencers and loose parts.
- Visually inspect compressor and compressor discharge case hooks for signs of wear.
- Visually inspect compressor discharge case struts for signs of cracking.
- Visually inspect compressor discharge case inner barrel if accessible.
- Visually inspect the turbine shell shroud hooks for sign of cracking.

Major Inspection

Hot Gas Path Inspection Scope—Plus:

Key Hardware	Inspect For	Potential Action
Compressor blading	Foreign object damage	Repair/refurbishment/replace
Compressor and turbine rotor dovetails	Oxidation/corrosion/erosion	Stator shrouds • Cracking/oxidation/erosion
Journals and seal surfaces	Cracking	Buckets • Coating deterioration • FOD/rubs/cracking • Tip shroud deflection • Creep life limit
Bearing seals	Leaks	Nozzles • Severe deterioration
Exhaust system	Abnormal wear	IGV bushings • Wear
	Missing hardware	Bearings/seals • Scoring/wear
	Clearance limits	Compressor blades • Corrosion/erosion • Rubs/FOD
		Rotor inspection
Compressor discharge case	Cracks	Repair or monitoring
Turbine shell	Cracks	Repair or monitoring
Compressor and compressor discharge case hooks	Wear	Repair
Cases – exterior and interior	Cracks	Repair or monitoring
Exhaust diffuser	Cracks	Weld repair
Exhaust diffuser insulation	Loose/missing parts	Replace/tighton parts
Forward diffuser flex seal	Wear/cracked parts	Replace seals

Criteria
- Op. & Instr. Manual
- TILs
- GE Field Engineer

Inspection Methods
- Visual
- Liquid Penetrant
- Borescope
- Ultrasonics

Figure 41. Gas turbine major inspection – key elements

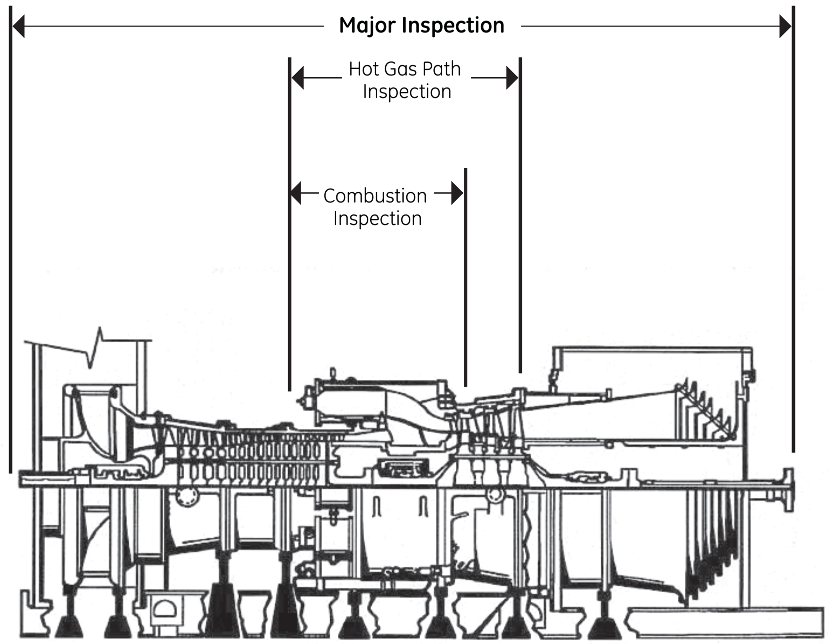

Figure 42. Major inspection work scope

- Visually inspect the exhaust diffuser for any cracks in flow path surfaces. Inspect insulated surfaces for loose or missing insulation and/or attachment hardware in internal and external locations. In E-class machines, inspect the insulation on the radial diffuser and inside the exhaust plenum as well.
- Inspect exhaust frame flex seals, L-seals, and horizontal joint gaskets for any signs of wear or damage. Inspect steam gland seals for wear and oxidation.
- Check torque values for steam gland bolts and re-torque to full values.
- Check alignment – gas turbine to generator/gas turbine to accessory gear.

Comprehensive inspection and maintenance guidelines have been developed by GE and are provided in the O&M Manual to assist users in performing each of the inspections previously described.

Parts Planning

Lack of adequate on-site spares can have a major effect on plant availability; therefore, prior to a scheduled disassembly type of inspection, adequate spares should be on-site. A planned outage such as a combustion inspection, which should only take two to five days, could take weeks. GE will provide recommendations regarding the types and quantities of spare parts needed; however, it is up to the owner to purchase these spare parts on a planned basis allowing adequate lead times.

Early identification of spare parts requirements ensures their availability at the time the planned inspections are performed. Refer to the *Reference Drawing Manual* provided as part of the comprehensive set of *O&M Manuals* to aid in identification and ordering of gas turbine parts.

Additional benefits available from the renewal parts catalog data system are the capability to prepare recommended spare parts lists for the combustion, hot gas path and major inspections as well as capital and operational spares.

Typical expectations for estimated repair cycles for some of the major components are shown in *Appendix D*. These tables assume that operation of the unit has been in accordance with all of the manufacturer's specifications and instructions.

Maintenance inspections and repairs are also assumed to be done in accordance with the manufacturer's specifications and instructions. The actual repair and replacement cycles for any particular gas turbine should be based on the user's operating procedures, experience, maintenance practices and repair practices. The maintenance factors previously described can have a major impact on both the component repair interval and service life. For this reason, the intervals given in *Appendix D* should only be used as guidelines and not certainties for long range parts planning. Owners may want to include contingencies in their parts planning.

The expected repair and replacement cycle values reflect current production hardware.

To achieve these lives, current production parts with design improvements and newer coatings are required. With earlier production hardware, some of these lives may not be achieved. Operating factors and experience gained during the course of recommended inspection and maintenance procedures will be a more accurate predictor of the actual intervals.

Appendix D shows expected repair and replacement intervals based on the recommended inspection intervals shown in *Figure 44*. The application of inspection (or repair) intervals other than those shown in *Figure 44* can result in different replacement intervals (as a function of the number of repair intervals) than those shown in *Appendix D*. See your GE representative for details on a specific system. It should be recognized that, in some cases, the service life of a component is reached when it is no longer economical to repair any deterioration as opposed to replacing at a fixed interval. This is illustrated in *Figure 43* for a first stage nozzle, where repairs continue until either the nozzle cannot be restored to minimum acceptance standards or the repair cost exceeds or approaches the replacement cost. In other cases, such as first-stage buckets, repair options are limited by factors such as irreversible material damage. In both cases, users should follow GE recommendations regarding replacement or repair of these components.

While the parts lives shown in *Appendix D* are guidelines, the life consumption of individual parts within a parts set can have variations. The repair versus replacement economics shown in *Figure 43* may lead to a certain percentage of "fallout," or scrap, of parts being repaired. Those parts that fallout during the repair process will need to be replaced by new parts. Parts fallout will vary based on the unit operating environment history, the specific part design, and the current state-of-the-art for repair technology.

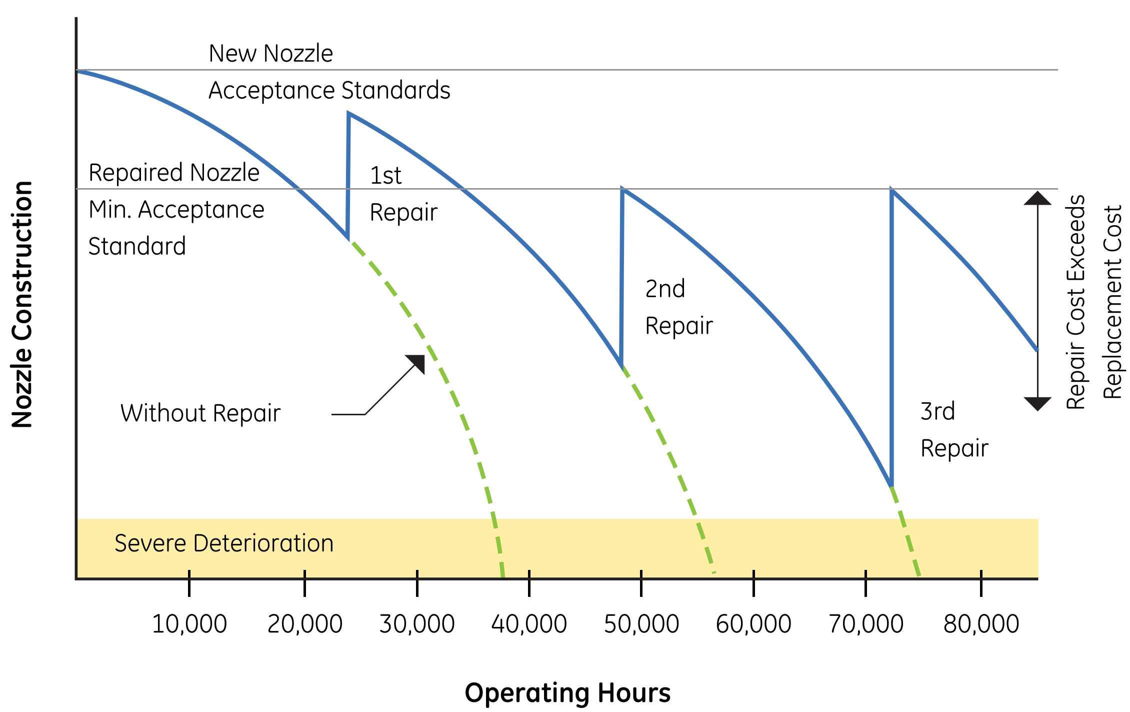

Figure 43. First-stage nozzle wear-preventive maintenance: gas fired – continuous dry – base load

Type of Inspection	Combustion System	Factored Hours/Factored Starts				
		MS3002K	MS5001PA/MS5002C, D	MS6B	MS7E/EA	MS9E
Combustion	Non-DLN	24000/400	12000/800 (1) (3)	12000/1200 (2) (3)	8000/900 (3)	8000/900 (3)
	DLN		8000/400	12000/450	12000/450	12000/450
Hot Gas Path		24000/1200	Eliminated/1200	24000/1200	24000/1200	24000/900
Major		48000/2400	48000/2400	48000/2400	48000/2400	48000/2400

Type of Inspection	Combustion System	Factored Hours/Factored Starts							
		MS6FA	MS6FA+e	MS7F/FA/FA+	MS7FA+e	MS9F/FA/FA+	MS9FA+e	MS7FB	MS9FB
Combustion	Non-DLN	8000/450	8000/450						
	DLN	8000/450	12000/450	8000/450	12000/450	8000/450	8000/450	12000/450	12000/450
Hot Gas Path		24000/900	24000/900	24000/900	24000/900	24000/900	24000/900	24000/900	24000/900
Major		48000/2400	48000/2400	48000/2400	48000/2400	48000/2400	48000/2400	48000/2400	48000/2400

Factors that can reduce maintenance intervals:

- Fuel
- Load setting
- Steam/water injection
- Peak load firing operation
- Trips
- Start cycle
- Hardware design

1. Units with Lean Head End liners have a 400-starts combustion inspection interval.
2. Machines with 6581 and 6BeV combustion hardware have a 12000/600 combustion inspection interval.
3. Multiple Non-DLN configurations exist (Standard, MNQC, IGCC). The typical case is shown; however, different quoting limits may exist on a machine and hardware basis. Contact a GE Energy representative for further information.

Note: Factored Hours/Starts intervals include an allowance for nominal trip maintenance factor effects.

Hours/Starts intervals for Major Inspection are quoted in Actual Hours and Actual Starts.

Repair/replace cycles reflect current production hardware, unless otherwise noted, and operation in accordance with manufacturer specifications. They represent initial recommended intervals in the absence of operating and condition experience.

Figure 44. Base line recommended inspection intervals: base load – gas fuel – dry

Inspection Intervals

In the absence of operating experience and resulting part conditions, *Figure 44* lists the recommended combustion, hot gas path and major inspection intervals for current production GE turbines operating under typical conditions of gas fuel, base load, and no water or steam injection. These recommended intervals represent factored hours or starts calculated using maintenance factors to account for application specific operating conditions. Initially, recommended intervals are based on the expected operation of a turbine at installation, but this should be reviewed and adjusted as actual operating and maintenance data are accumulated. While reductions in the recommended intervals will result from the factors described previously or unfavorable operating experience, increases in the recommended intervals may also be considered where operating experience has been favorable. The condition of the combustion and hot gas path parts provides a good basis for customizing a program of inspection and maintenance. The condition of the compressor and bearing assemblies is the key driver in planning a Major Inspection. Historical operation and machine conditions can be used to tailor custom maintenance programs such as optimized repair and inspection criteria to specific sites/machines. GE leverages these principles and accumulated site and fleet experience in a "Condition Based Maintenance" program as the basis for maintenance of units under Contractual Service Agreements. This experience was accumulated on units that operate with GE approved repairs, field services, monitoring and full compliance to GE's technical recommendations.

GE can assist operators in determining the appropriate maintenance intervals for their particular application. Equations have been developed that account for the factors described earlier and can be used to determine application specific hot gas path and major inspection intervals.

Borescope Inspection Interval

In addition to the planned maintenance intervals, which undertake scheduled inspections or component repairs or replacements, borescope inspections (BIs) should be conducted to identify any additional actions, as discussed in the sections "Gas Turbine Design Maintenance Features." Such inspections may identify additional areas to be addressed at a future scheduled maintenance outage, assist with parts or resource planning, or indicate the need to change the timing of a future outage to minimize potential effects. The BI should use all the available access points to verify the safe and uncompromised condition of the static and rotating hardware. As much of the Major Inspection workscope as possible should be done using this visual inspection without dissassembly. Refer to *Figure 4* for standard recommended BI frequency. Specific concerns may warrant subsequent BIs in order to operate the unit to the next scheduled outage without teardown.

Hot Gas Path Inspection Interval

The hours-based hot gas path criterion is determined from the equation given in *Figure 45*. With this equation, a maintenance factor is determined that is the ratio of factored operating hours and actual operating hours. The factored hours consider the specifics of the duty cycle relating to fuel type, load setting and steam or water injection. Maintenance factors greater than one reduce the hot gas path inspection interval from the 24,000 hour ideal case for continuous base load, gas fuel and no steam or water injection. To determine the application specific maintenance interval, the maintenance factor is divided into 24,000, as shown in *Figure 45*.

The starts-based hot gas path criterion is determined from the equation given in *Figure 46*. As with the hours-based criteria, an application specific starts-based hot gas path inspection interval is calculated from a maintenance factor that is determined from the number of trips typically being experienced, the load level and loading rate.

As previously described, the hours and starts operating spectrum for the application is evaluated against the recommended hot gas path intervals for starts and for hours. The limiting criterion (hours or starts) determines the maintenance interval. An example of the use of these equations for the hot gas path is contained in *Appendix A*.

Hours-Based HGP Inspection

$$\text{Maintenance Interval (Hours)} = \frac{24000}{\text{Maintenance Factor}}$$

Where:

$$\text{Maintenance Factor} = \frac{\text{Factored Hours}}{\text{Actual Hours}}$$

Factored Hours = $(K + M \times I) \times (G + 1.5D + A_f H + ApP)$

Actual Hours = $(G + D + H + P)$

G = Annual Base Load Operating hours on Gas Fuel

D = Annual Base Load Operating hours on Distillate Fuel

H = Annual Operating Hours on Heavy Fuel

A_f = Heavy Fuel Severity Factor (Residual A_f = 3 to 4, Crude A_f = 2 to 3)

Ap = Peak Load Factor (See Figure 12)

P = Annual Peak Load Operating Hours on gas or distillate

I = Percent Water/Steam Injection Referenced to Compressor Inlet Air Flow

M&K = Water/Steam Injection Constants

M	K	Control	Steam Injection	N2/N3 Material
0	1	Dry	<2.2%	GTD-222/FSX-414
0	1	Dry	>2.2%	GTD-222
.18	.6	Dry	>2.2%	FSX-414
.18	1	Wet	>0%	GTD-222
.55	1	Wet	>0%	FSX-414

Figure 45. Hot gas path maintenance interval: hours-based criterion

Starts-Based HGP Inspection

$$\text{Maintenance Interval (Starts)} = \frac{S}{\text{Maintenance Factor}}$$

Where:

$$\text{Maintenance Factor} = \frac{\text{Factored Starts}}{\text{Actual Starts}}$$

Factored Starts = $0.5N_A + N_B + 1.3N_P + 20E + 2F + \sum_{i=1}^{\eta} (a_{Ti} - 1)\, T_i$

Actual Starts = $(N_A + N_B + N_P)$

S = Maximum Starts-Based Maintenance Interval (Model Size Dependent)

N_A = Annual Number of Part Load Start/Stop Cycles (<60% Load)

N_B = Annual Number of Base Load Start/Stop Cycles

N_P = Annual Number of Peak Load Start/Stop Cycles (>100% Load)

E = Annual Number of Emergency Starts

F = Annual Number of Fast Load Starts

T = Annual Number of Trips

a_T = Trip Severity Factor = f(Load) (See Figure 21)

η = Number of Trip Categories (i.e.Full Load, Part Load, etc.)

Model Series	S	Model Series	S
MS6B/MS7EA	1,200	MS9E	900
MS6FA	900	MS7F/MS9F	900

Figure 46. Hot gas path maintenance interval: starts-based criterion

Rotor Inspection Interval

Like HGP components, the unit rotor has a maintenance interval involving removal, disassembly and thorough inspection. This interval indicates the serviceable life of the rotor and is generally considered to be the teardown inspection and repair/replacement interval for the rotor. These intervals are traditionally concurrent with hot gas path and major inspections, however, it should be noted that the maintenance factors for rotor maintenance intervals are distinct and different from those of combustion and hot gas path components. As such, the calculation of consumed life on the rotor may vary from that of combustion and hot gas path components. Customers should contact GE when their rotor has reached the end of its serviceable life for technical advisement.

The starts-based rotor maintenance interval is determined from the equation given in *Figure 47*. Adjustments to the rotor maintenance interval are determined from rotor-based operating factors as were described previously. In the calculation for the starts-based rotor maintenance interval, equivalent starts are determined for cold, warm, and hot starts over a defined time period by multiplying the appropriate cold, warm and hot start operating factors by the number of cold, warm and hot starts respectively. In this calculation, start classification is key. Additionally, equivalent starts for trips from load are added. The total equivalent starts are divided by the actual number of starts to yield the maintenance factor. The rotor starts-based maintenance interval for a specific application is determined by dividing the baseline rotor maintenance interval of 5000 starts by the calculated maintenance factor. As indicated in *Figure 47*, the baseline rotor maintenance interval is also the maximum interval, since calculated maintenance factors less than one are not considered.

Figure 48 describes the procedure to determine the hours-based maintenance criterion. Peak load operation is the primary maintenance factor for the F class rotor and will act to increase the hours-based maintenance factor and to reduce the rotor maintenance interval.

When the rotor reaches the limiting inspection interval determined from the equations described in *Figures 47 and 48*, a refurbishment of the rotor is required so that a complete inspection of the rotor components in both the compressor and turbine can be performed. It should be expected that some rotor components will either have reached the end of their serviceable life or will have a minimal

Starts-Based Rotor Inspection

$$\text{Rotor Maintenance Interval} = \frac{\mathbf{5000}^{(1)}}{\textbf{Maintenance Factor}}$$

(Not to exceed 5000 starts)
MF>=1

$$\text{Maintenance Factor} = \frac{F_h \cdot N_h + F_{w1} \cdot N_{w1} + F_{w2} \cdot N_{w2} + F_c \cdot N_c + F_t \cdot N_t}{N_h + N_{w1} + N_{w2} + N_c}$$

Number of Starts

- N_h = Number of hot starts
- N_{w1} = Number of Warm1 starts
- N_{w2} = Number of Warm2 starts
- N_c = Number of cold starts
- N_t = Number of trips

Start Factors

- F_h = Hot start factor (Down 1-4 hr)*
- F_{w1} = Warm1 start factor (Down 4-20 hr)
- F_{w2} = Warm2 start factor (Down 20-40 hr)
- F_c = Cold start factor (Down >40 hr)
- F_t = Trip from load factor

(1) F class

Note: Start factors for 7/9 FA+e machines are tabulated in Figure 23.
For other F Class machines, refer to applicable TILs.

Figure 47. Rotor maintenance interval: starts-based criterion

Hours-Based Rotor Inspection

$$\text{Rotor Maintenance Interval} = \frac{144000^{(1)}}{\text{Maintenance Factor}}$$

$$\text{Maintenance Factor} = \frac{H + 2*P^{(2)}}{H + P}$$

Where:

H ~ Base load hours

P ~ Peak load hours

(1) F class

(2) For E-class, MF = (H + 2*P + 2*TG) / (H + P), where TG is hours on turning gear.

Note: To diminish potential turning gear impact, Major Inspections must include a thorough visual and dimensional examination of the hot gas path turbine rotor dovetails for signs of wearing, galling, fretting or cracking. If inspections and repairs are performed to the dovetails, time on turning gear may be omitted from the hours based maintenance factor.

Figure 48. Rotor maintenance interval: hours-based criterion

amount of residual life remaining and will require replacement at this inspection point. Depending on the extent of refurbishment and part replacement, subsequent inspections may be required at a reduced interval.

As with major inspections, the rotor repair interval should include thorough dovetail inspections for wear and cracking. The baseline rotor life is predicated upon sound inspection results at the majors. The baseline intervals of 144,000 hours and 5000 starts in *Figures 47 and 48* pertain to F class rotors. For rotors other than F class, rotor maintenance should be performed at intervals recommended by GE through issued Technical Information Letters (TILs). Where no recommendations have been made, rotor inspection should be performed at 5,000 factored starts or 200,000 factored hours.

Combustion Inspection Interval

Equations have been developed that account for the earlier mentioned factors affecting combustion maintenance intervals. These equations represent a generic set of maintenance factors that provide general guidance on maintenance planning. As such, these equations do not represent the specific capability of any given combustion system. They do provide, however, a generalization of combustion system experience. For combustion parts, the base line operating conditions that result in a maintenance factor of one are normal fired startup and shutdown (no trip) to base load on natural gas fuel without steam or water injection.

An hours-based combustion maintenance factor can be determined from the equations given in *Figure 49* as the ratio of factored-hours to actual operating hours. Factored-hours considers the effects of fuel type, load setting and steam or water injection. Maintenance factors greater than one reduce recommended combustion inspection intervals from those shown in *Figure 44* representing baseline operating conditions. To obtain a recommended inspection interval for a specific application, the maintenance factor is divided into the recommended base line inspection interval.

Maintenance Factor = (Factored Hours)/(Actual Hours)

Factored Hours = $\sum (K_i \times Af_i \times Ap_i \times t_i)$, i = 1 to n Operating Modes

Actual Hours = $\sum (t_i)$, i = 1 to n Operating Modes

Where:

- i = Discrete Operating mode (or Operating Practice of Time Interval)
- t_i = Operating hours at Load in a Given Operating mode
- Ap_i = Load Severity factor
  - Ap = 1.0 up to Base Load
  - Ap = For Peak Load Factor See Figure 12
- Af_i = Fuel Severity Factor (dry)
  - Af = 1.0 for Gas Fuel (1)
  - Af = 1.5 for Distillate Fuel, Non-DLN (2.5 for DLN)
  - Af = 2.5 for Crude (Non-DLN)
  - Af = 3.5 for Residual (Non-DLN)
- K_i = Water/Steam Injection Severity Factor
  - (% Steam Referenced to Compressor Inlet Air Flow, w/f = Water to Fuel Ratio)
  - K = Max(1.0, exp(0.34(%Steam – 2.00%))) for Steam, Dry Control Curve
  - K = Max(1.0, exp(0.34(%Steam – 1.00%))) for Steam, Wet Control Curve
  - K = Max(1.0, exp(1.80(w/f – 0.80))) for Water, Dry Control Curve
  - K = Max(1.0, exp(1.80(w/f – 0.40))) for Water, Wet Control Curve

(1) Af = 10 for DLN 1 extended lean-lean, DLN 2.0 lean-lean and DLN 2+ in extended sub-piloted and extended piloted premixed operating modes.

Figure 49. Combustion inspection hours-based maintenance factors

Maintenance Factor = (Factored starts)/(Actual Starts)
Factored Starts = $\sum (K_i \times Af_i \times At_i \times Ap_i \times As_i \times N_i)$, i = 1 to n Start/Stop Cycles
Actual Starts = $\sum (N_i)$, i = 1 to n Start/Stop Cycles
Where:

i = Discrete Start/Stop Cycle (or Operating Practice)
N_i = Start/Stop Cycles in a Given Operating Mode
As_i = Start Type Severity Factor
- As = 1.0 for Normal Start
- As = 1.2 for Start with Fast Load
- As = 3.0 for Emergency Start

Ap_i = Load Severity Factor
- Ap = 1.0 up to Base Load
- Ap = exp(0.009 x Peak Firing Temp Adder in deg F) for Peak Load

At_i = Trip Severity Factor
- At = 0.5 + exp(0.0125*%Load) for Trip

Af_i = Fuel Severity Factor (Dry, at Load)
- Af = 1.0 for Gas Fuel
- Af = 1.25 for Non-DLN (or 1.5 for DLN) for Distillate Fuel
- Af = 2.0 for Crude (Non-DLN)
- Af = 3.0 for Residual (Non-DLN)

K_i = Water/Steam Injection Severity Factor
(% Steam Referenced to Compressor Inlet Air Flow, w/f = Water to Fuel Ratio)
- K = Max(1.0, exp(0.34(%Steam – 1.00%))) for Steam, Dry Control Curve
- K = Max(1.0, exp(0.34(%Steam – 0.50%))) for Steam, Wet Control Curve
- K = Max(1.0, exp(1.80(w/f – 0.40))) for Water, Dry Control Curve
- K = Max(1.0, exp(1.80(w/f – 0.20))) for Water, Wet Control Curve

Figure 50. Combustion inspection starts-based maintenance factors

A starts-based combustion maintenance factor can be determined from the equations given in *Figure 50* and considers the effect of fuel type, load setting, emergency starts, fast loading rates, trips and steam or water injection. An application specific recommended inspection interval can be determined from the baseline inspection interval in *Figure 44* and the maintenance factor from *Figure 50*. *Appendix B* shows six example maintenance factor calculations using the above hours and starts maintenance factors equations.

Manpower Planning

It is essential that advanced manpower planning be conducted prior to an outage. It should be understood that a wide range of experience, productivity and working conditions exist around the world. However, based upon maintenance inspection man-hour assumptions, such as the use of an average crew of workers in the United States with trade skill (but not necessarily direct gas turbine experience), with all needed tools and replacement parts (no repair time) available, an estimate can be made. These estimated craft labor man-hours should include controls and accessories and the generator. In addition to the craft labor, additional resources are needed for technical direction of the craft labor force, specialized tooling, engineering reports, and site mobilization/demobilization.

Inspection frequencies and the amount of downtime varies within the gas turbine fleet due to different duty cycles and the economic need for a unit to be in a state of operational readiness. It can be demonstrated that an 8000-hour interval for a combustion inspection with minimum downtime can be achievable based on the above factors. Contact your local GE Energy representative for the specific man-hours and recommended crew size for your specific unit.

Depending upon the extent of work to be done during each maintenance task, a cooldown period of 4 to 24 hours may be required before service may be performed. This time can be utilized productively for job move-in, correct tagging and locking equipment out-of-service and general work preparations. At the conclusion of the maintenance work and systems check out, a turning gear time of two to eight hours is normally allocated prior to starting the unit. This time can be used for job clean-up and preparing for start.

Local GE field service representatives are available to help plan your maintenance work to reduce downtime and labor costs. This planned approach will outline the renewal parts that may be needed and the projected work scope, showing which tasks can be accomplished in parallel and which tasks must be sequential.

Planning techniques can be used to reduce maintenance cost by optimizing lifting equipment schedules and manpower requirements. Precise estimates of the outage duration, resource requirements, critical-path scheduling, recommended replacement parts, and costs associated with the inspection of a specific installation may be sourced from the local GE field services office.

Conclusion

GE heavy-duty gas turbines are designed to have an inherently high availability. To achieve maximum gas turbine availability, an owner must understand not only the equipment, but the factors affecting it. This includes the training of operating and maintenance personnel, following the manufacturer's recommendations, regular periodic inspections and the stocking of spare parts for immediate replacement. The recording and analysis of operating data, is essential to preventative and planned maintenance. A key factor in achieving this goal is a commitment by the owner to provide effective outage management and full utilization of published instructions and the available service support facilities.

It should be recognized that, while the manufacturer provides general maintenance recommendations, it is the equipment user who has the major impact upon the proper maintenance and operation of equipment. Inspection intervals for optimum turbine service are not fixed for every installation, but rather are developed through an interactive process by each user, based on past experience and trends indicated by key turbine factors. In addition, through application of a Contractual Service Agreement to a particular turbine, GE can work with a user to establish a maintenance program that may differ from general recommendations but will be consistent with contractual responsibilities.

The level and quality of a rigorous maintenance program have a direct impact on equipment reliability and availability. Therefore, a rigorous maintenance program which optimizes both maintenance cost and availability is vital to the user. A rigorous maintenance program will minimize overall costs, keep outage downtimes to a minimum, improve starting and running reliability and provide increased availability and revenue earning ability for GE gas turbine users.

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Appendix

A.1) Example 1 – Hot Gas Path Maintenance Interval Calculation

An MS7001EA user has accumulated operating data since the last hot gas path inspection and would like to estimate when the next one should be scheduled. The user is aware from GE publications that the normal HGP interval is 24,000 hours if operating on natural gas, with no water or steam injection, and at base load. It is also understood that the nominal starts interval is 1200, based on normal startups, no trips, no emergency starts. The actual operation of the unit since the last hot gas path inspection is much different from the GE "baseline case."

Annual hours on natural gas, base load
$= G = 3200$ hr/yr

Annual hours on light distillate
$= D = 350$ hr/yr

Annual hours on peak load
$= P = 120$ hr/yr

Steam injection rate
$= I = 2.4\%$

Also, since the last hot gas path inspection,

140 Normal start-stop cycles:

40 Part load

100 Base load

0 Peak load

In addition,

E = 2 Emergency Starts w / ramp to base load

F = 5 Fast loads ending in a normal shutdown from base load

T = 20 Starts with trips from base load ($a_{Ti} = 8$)

For this particular unit, the second and third-stage nozzles are FSX-414 material. The unit operates on "dry control curve."

From *Figure 45*, at a steam injection rate of 2.4%, the value of "M" is .18, and "K" is .6.

From the hours-based criteria, the maintenance factor is determined from *Figure 45*.

$$MF = \frac{[K + M(I)] \times [G + 1.5(D) + Af(H) + A_P \times P]}{(G + D + H + P)}$$

Annual hours on peak load at +100 deg F firing temperature

$P = 120$ hr/yr

$A_P = 6$

$$MF = \frac{[.6 + .18(2.4)] \times [3200 + 1.5(350) + 0 + 6(120)]}{(3200 + 350 + 0 + 120)}$$

$MF = 1.25$

The hours-based adjusted inspection interval is therefore,

H = 24,000/1.25

H = 19,200 hours

[Note, since total annual operating hours is 3670, the estimated time to reach 19,200 hours is 5.24 years (19,200/3670).]

From the starts-based criteria, the maintenance factor is determined from *Figure 46*.

The total number of part load starts is

$N_A = 40$/yr

The total number of base load starts is

$N_B = 100 + 2 + 5 + 20 = 127$/yr

The total number of peak load starts is

$N_P = 0$/yr

$$MF = \frac{[0.5\,(N_A)+(N_B)+1.3(N_P)+20(E)+2(F) + \sum_{i=1}^{n}(a_{Ti} - 1)\,T_i}{N_A + N_B + N_P}$$

$$MF = \frac{0.5(40)+(127)+1.3(0)+20(2)+2(5)+(8-1)20}{40+127+0}$$

$MF = 2$

The adjusted inspection interval based on starts is

S = 1200/2.0

S = 600 starts [Note, since the total annual number of starts is 167, the estimated time to reach 600 starts is 600/167 = 3.6 years.]

In this case, the starts-based maintenance factor is greater than the hours maintenance factor and therefore the inspection interval is set by starts. The hot gas path inspection interval is 600 starts (or 3.6 years).

A.2) Example 2 – Hot Gas Path Factored Starts Calculation

An MS7001EA user has accumulated operating data for the past year of operation. This data shows number of trips from part, base, and peak load, as well as emergency starting and fast loading. The user would like to calculate the total number of factored starts in order to plan the next HGP outage. *Figure 46* is used to calculate the total number of factored starts as shown below.

Operational history:

150 Start-stop cycles per year:

- 40 Part load
- 60 Base load
- 50 Peak load

50 ending in trips:

- 10 from 105% load
- 5 from 50% load (part load)
- 35 from 65% load (base load)

In addition,

3 Emergency Starts w/ramp to base load:

- 2 ended in a trip from full load
- 1 ended in a normal shutdown

4 Fast loads:

- 1 tripped during loading at 50% load
- 3 achieved base load and ended in a normal shutdown

Total Starts

Part Load, $N_A = 40 + 1 = 41$

Base Load, $N_B = 60 + 3 + 3 = 66$

Peak Load, $N_P = 50$

Total Trips

1. 50% load ($aT_1 = 6.5$), $T_1 = 5 + 1 = 6$
2. Full load ($aT_2 = 8$), $T_2 = 35 + 2 = 37$
3. Peak load ($aT_3 = 10$), $T_3 = 10$

Additional Cycles

Emergency starting, E = 3

Fast loading, F = 4

From the starts-based criteria, the total number of factored starts is determined from *Figure 46*.

$$FS = 0.5(NA)+(NB)+1.3(NP)+20(E)+2(F)+\sum_{i=1}^{n}(a_{Ti}-1)\,T_i$$

$$FS = 0.5(41)+(66)+1.3(50)+20(3)+2(4)+[(6.5-1)6+(8-1)37+(10-1)10]=601.50$$

$$AS = 41 + 66 + 50 = 157$$

$$MF = \frac{601.5}{157} = 3.8$$

B) Examples – Combustion Maintenance Interval Calculations (reference *Figures* 49 and 50)

DLN 1 Peaking Duty with Power Augmentation

+50F Tfire Increase		Gas Fuel	
3.5% Steam Augmentation		6 Hours/Start	
Start with Fast Load		Wet Control Curve	
Normal Shutdown (No Trip)			
Factored Hours = Ki * Afi * Api * ti =			34.5 Hours
Hours Maintenance Factor =		(34.5/6)	**5.8**
Where	Ki =	2.34 Max(1.0, exp(0.34(3.50-1.00))) Wet	
	Afi =	1.00 Gas Fuel	
	Api =	2.46 exp(0.018(50)) Peaking	
	ti =	6.0 Hours/Start	
Factored Starts = Ki * Afi * Ati * Api * Asi * Ni =			5.2 Starts
Starts Maintenance Factor =		(5.2/1)	**5.2**
Where	Ki =	2.77 Max(1.0, exp(0.34(3.50-0.50))) Wet	
	Afi =	1.00 Gas Fuel	
	Ati =	1.00 No Trip at Load	
	Api =	1.57 exp(0.009(50)) Peaking	
	Asi =	1.20 Start with Fast Load	
	Ni =	1.0 Considering Each Start	

Standard Combustor Baseload on Crude Oil

No Tfire Increase		Crude Oil Fuel	
1.0 Water/Fuel Ratio		220 Hours/Start	
Normal Start and Load		Dry Control Curve	
Normal Shutdown (No Trip)			
Factored Hours = Ki * Afi * Api * ti =			788.3 Hours
Hours Maintenance Factor =		(788.3/220)	**3.6**
Where	Ki =	1.43 Max(1.0, exp(1.80(1.00-0.80))) Dry	
	Afi =	2.50 Crude Oil, Std (Non-DLN)	
	Api =	1.00 Baseload	
	ti =	220.0 Hours/Start	
Factored Starts = Ki * Afi * Ati * Api * Asi * Ni =			5.9 Starts
Starts Maintenance Factor =		(5.9/1)	**5.9**
Where	Ki =	2.94 Max(1.0, exp(1.80(1.00-0.40))) Dry	
	Afi =	2.00 Crude Oil, Std (Non-DLN)	
	Ati =	1.00 No Trip at Load	
	Api =	1.00 Baseload	
	Asi =	1.00 Normal Start	
	Ni =	1.0 Considering Each Start	

DLN 2.6 Baseload on Distillate

No Tfire Increase		Distillate Fuel	
1.1 Water/Fuel Ratio		220 Hours/Start	
Normal Start		Dry Control Curve	
Normal Shutdown (No Trip)			
Factored Hours = Ki * Afi * Api * ti =			943.8 Hours
Hours Maintenance Factor =		(943.8/220)	**4.3**
Where	Ki =	1.72 Max(1.0, exp(1.80(1.10-0.80))) Dry	
	Afi =	2.50 Distillate Fuel, DLN	
	Api =	1.00 Baseload	
	ti =	220.0 Hours/Start	
Factored Starts = Ki * Afi * Ati * Api * Asi * Ni =			5.3 Starts
Starts Maintenance Factor =		(5.3/1)	**5.3**
Where	Ki =	3.53 Max(1.0, exp(1.80(1.10-0.40))) Dry	
	Afi =	1.50 Distillate Fuel, DLN	
	Ati =	1.00 No Trip at Load	
	Api =	1.00 Baseload	
	Asi =	1.00 Normal Start	
	Ni =	1.0 Considering Each Start	

DLN 2.6 Baseload on Gas with Trip @ Load

No Tfire Increase		Gas Fuel	
No Steam/Water Injection		168 Hours/Start	
Normal Start and Load		Dry Control Curve	
Trip @ 60% Load			
Factored Hours = Ki * Afi * Api * ti =			168.0 Hours
Hours Maintenance Factor =		(168.0/168)	**1.0**
Where	Ki =	1.00 No Injection	
	Afi =	1.00 Gas Fuel	
	Api =	1.00 Baseload	
	ti =	168.0 Hours/Start	
Factored Starts = Ki * Afi * Ati * Api * Asi * Ni =			2.6 Starts
Starts Maintenance Factor =		(2.6/1)	**2.6**
Where	Ki =	1.00 No Injection	
	Afi =	1.00 Gas Fuel	
	Ati =	2.62 0.5+exp(0.0125*60) for Trip	
	Api =	1.00 Baseload	
	Asi =	1.00 Normal Start	
	Ni =	1.0 Considering Each Start	

DLN 1 Combustor Baseload on Distillate

No Tfire Increase		Distillate Fuel	
0.9 Water/Fuel Ratio		500 Hours/Start	
Normal Start		Dry Control Curve	
Normal Shutdown (No Trip)			
Factored Hours = Ki * Afi * Api * ti =			1496.5 Hours
Hours Maintenance Factor =		(1496.5/500)	**3.0**
Where	Ki =	1.20 Max(1.0, exp(1.80(0.90-0.80))) Dry	
	Afi =	2.50 Distillate Fuel, DLN 1	
	Api =	1.00 Partload	
	ti =	500.0 Hours/Start	
Factored Starts = Ki * Afi * Ati * Api * Asi * Ni =			3.7 Starts
Starts Maintenance Factor =		(3.7/1)	**3.7**
Where	Ki =	2.46 Max(1.0, exp(1.80(0.90-0.40))) Dry	
	Afi =	1.50 Distillate Fuel, DLN	
	Ati =	1.00 No Trip at Load	
	Api =	1.00 Part Load	
	Asi =	1.00 Normal Start	
	Ni =	1.0 Considering Each Start	

DLN 2.6 Peak Load on Gas with Emergency Starts

+35F Tfire Increase		Gas Fuel	
3.5% Steam Augmentation		4 Hours/Start	
Emergency Start		Dry Control Curve	
Normal Shutdown (No Trip)			
Factored Hours = Ki * Afi * Api * ti =			12.5Hours
Hours Maintenance Factor =		(12.5/4)	**3.1**
Where	Ki =	1.67 Max(1.0, exp(0.34(3.50-2.00)))	
	Afi =	1.00 Gas Fuel	
	Api =	1.88 exp(0.018(35)) Peaking	
	ti =	4.0 Hours/Start	
Factored Starts = Ki * Afi * Ati * Api * Asi * Ni =			9.6 Starts
Starts Maintenance Factor =		(9.6/1)	**9.6**
Where	Ki =	2.34 Max(1.0, exp(0.34(3.50-1.00))) Dry	
	Afi =	1.00 Gas Fuel	
	Ati =	1.00 No Trip at Load	
	Api =	1.37 exp(0.009(35)) Peaking	
	Asi =	3.00 Emergency Start	
	Ni =	1.0 Considering Each Start	

Figure B-1. Combustion maintenance interval calculations

C) Definitions

Reliability: Probability of not being forced out of service when the unit is needed — includes forced outage hours (FOH) while in service, while on reserve shutdown and while attempting to start normalized by period hours (PH) — units are %.

Reliability	=	(1-FOH/PH) (100)
FOH	=	total forced outage hours
PH	=	period hours

Availability: Probability of being available, independent of whether the unit is needed – includes all unavailable hours (UH) – normalized by period hours (PH) – units are %:

Availability	=	(1-UH/PH) (100)
UH	=	total unavailable hours (forced outage, failure to start, scheduled maintenance hours, unscheduled maintenance hours)
PH	=	period hours

Equivalent Reliability: Probability of a multi-shaft combined-cycle power plant not being totally forced out of service when the unit is required includes the effect of the gas and steam cycle MW output contribution to plant output – units are %.

Equivalent Reliability =

$$\left[1 - \left[\frac{\text{GT FOH}}{\text{GT PH}} + B\left(\frac{\text{HRSG FOH}}{\text{B PH}} + \frac{\text{ST FOH}}{\text{ST PH}}\right)\right] \times 100\right]$$

GT FOH	=	Gas Turbine Forced Outage Hours
GT PH	=	Gas Turbine Period Hours
HRSG FOH	=	HRSG Forced Outage Hours
B PH	=	HRSG Period Hours
ST FOH	=	Steam Turbine Forced Outage Hours
ST PH	=	Steam Turbine Period Hours
B	=	Steam Cycle MW Output Contribution (normally 0.30)

Equivalent Availability: Probability of a multi-shaft combined-cycle power plant being available for power generation — independent of whether the unit is needed — includes all unavailable hours — includes the effect of the gas and steam cycle MW output contribution to plant output; units are %.

Equivalent Availability =

$$\left[1 - \left[\frac{\text{GT UH}}{\text{GT PH}} + B\left(\frac{\text{HRSG UH}}{\text{GT PH}} + \frac{\text{ST UH}}{\text{ST PH}}\right)\right] \times 100\right]$$

GT UH	=	Gas Turbine Unavailable Hours
GT PH	=	Gas Turbine Period Hours
HRSG UH	=	HRSG Total Unavailable Hours
ST UH	=	Steam Turbine Unavailable Hours
ST PH	=	Steam Turbine Period Hours
B	=	Steam Cycle MW Output Contribution (normally 0.30)

MTBF–Mean Time Between Failure: Measure of probability of completing the current run. Failure events are restricted to forced outages (FO) while in service – units are service hours.

MTBF	=	SH/FO
SH	=	Service Hours
FO	=	Forced Outage Events from a Running (On-line) Condition

Service Factor: Measure of operational use, usually expressed on an annual basis – units are %.

SF = SH/PH x 100
SH = Service Hours on an annual basis
PH = Period Hours (8760 hours per year)

Operating Duty Definition:

Duty	Service Factor	Fired Hours/Start
Stand-by	< 1%	1 to 4
Peaking	1% – 17%	3 to 10
Cycling	17% – 50%	10 to 50
Continuous	> 90%	>> 50

D) Repair and Replacement Cycles (Natural Gas Only)

MS3002K Parts

	Repair Interval	Replace Interval (Hours)	Replace Interval (Starts)
Combustion Liners	CI	2 (CI)	4 (CI)
Transition Pieces	CI, HGPI	2 (CI)	2 (HGPI)
Stage 1 Nozzles	HGPI	2 (HGPI)	2 (HGPI)
Stage 2 Nozzles	MI	2 (MI)	2 (MI)
Stage 1 Shrouds	MI	2 (MI)	2 (MI)
Stage 2 Shrouds	MI	2 (MI)	2 (MI)
Stage 1 Bucket	–	1 (MI)(1)	3 (HGPI)
Stage 2 Bucket	–	1 (MI)	3 (HGPI)

Note: Repair/replace cycles reflect current production hardware, unless otherwise noted, and operation in accordance with manufacturer specifications. They represent initial recommended intervals in the absence of operating and condition experience. For factored hours and starts of the repair intervals, refer to Figure 44.

CI = Combustion Inspection Interval
HGPI = Hot Gas Path Inspection Interval
MI = Major Inspection Interval

(1) GE approved repair at 24,000 hours may extend life to 72,000 hours.

Figure D-1. Estimated repair and replacement cycles

MS5001PA / MS5002C,D Parts

	Repair Interval	Replace Interval (Hours)	Replace Interval (Starts)
Combustion Liners	CI	4 (CI)	3 (CI) / 4 (CI)(1)
Transition Pieces	CI, HGPI	4 (CI)(2)	3 (CI) / 4 (CI)(1)
Stage 1 Nozzles	HGPI, MI	2 (MI)	2 (HGPI)
Stage 2 Nozzles	HGPI, MI	2 (MI)	2 (HGPI) / 2 (MI)(3)
Stage 1 Shrouds	MI	2 (MI)	2 (MI)
Stage 2 Shrouds	–	2 (MI)	2 (MI)
Stage 1 Bucket	–	1 (MI)(4)	3 (HGPI)
Stage 2 Bucket	–	1 (MI)	3 (HGPI)

Note: Repair/replace cycles reflect current production hardware, unless otherwise noted, and operation in accordance with manufacturer specifications. They represent initial recommended intervals in the absence of operating and condition experience. For factored hours and starts of the repair intervals, refer to Figure 44.

CI = Combustion Inspection Interval
HGPI = Hot Gas Path Inspection Interval
MI = Major Inspection Interval

(1) 3 (CI) for non-DLN units, 4 (CI) for DLN units

(2) Repair interval is every 2 (CI)

(3) 2 (HGPI) for MS5001PA, 2 (MI) for MS5002C, D

(4) GE approved repair at 24,000 hours may extend life to 72,000 hours

Figure D-2. Estimated repair and replacement cycles

PG6541-61 (6B)

	Repair Interval	Replace Interval (Hours)	Replace Interval (Starts)
Stage 1 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 2 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 3 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 1 Shrouds	HGPI	2 (HGPI)	2 (HGPI)
Stage 2 Shrouds	HGPI	3 (HGPI)	4 (HGPI)
Stage 3 Shrouds	HGPI	3 (HGPI)	4 (HGPI)
Stage 1 Bucket	HGPI	2 (HGPI)(1) / 3 (HGPI)(2)	3 (HGPI)
Stage 2 Bucket	HGPI	3 (HGPI)(3)	4 (HGPI)
Stage 3 Bucket	HGPI	3 (HGPI)	4 (HGPI)

Note: Repair/replace cycles reflect current production hardware, unless otherwise noted, and operation in accordance with manufacturer specifications. They represent initial recommended intervals in the absence of operating and condition experience. For factored hours and starts of the repair intervals, refer to Figure 44.

HGPI = Hot Gas Path Inspection Interval

(1) 2 (HGPI) with no repairs at 24k hours.

(2) 3 (HGPI) with Strip, HIP Rejuvenation, and Re-coat at 24k hours.

(3) May require meeting tip shroud engagement criteria at prior HGP repair intervals. 3 (HGPI) for current design only. Consult your GE Energy representative for replace intervals by part number.

Figure D-3. Estimated repair and replacement cycles

PG6571-81 (6BU) / 6BeV Parts

	Repair Interval	Replace Interval (Hours)	Replace Interval (Starts)
Combustion Liners	CI	3 (CI) / 4 (CI)(1)	3 (CI) / 4 (CI)(1)
Caps	CI	3 (CI) / 4 (CI)(1)	3 (CI) / 4 (CI)(1)
Transition Pieces	CI	3 (CI) / 4 (CI)(1)	3 (CI) / 4 (CI)(1)
Fuel Nozzles	CI	3 (CI) / 4 (CI)(1)	3 (CI) / 4 (CI)(1)
Crossfire Tubes	CI	1 (CI)	1 (CI)
Crossfire Tube Retaining Clips	CI	1 (CI)	1 (CI)
Flow Divider (Distillate)	CI	3 (CI)	3 (CI)
Fuel Pump (Distillate)	CI	3 (CI)	3 (CI)
Stage 1 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 2 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 3 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 1 Shrouds	HGPI	2 (HGPI)	2 (HGPI)
Stage 2 Shrouds	HGPI	3 (HGPI)	4 (HGPI)
Stage 3 Shrouds	HGPI	3 (HGPI)	4 (HGPI)
Stage 1 Bucket	HGPI	3 (HGPI)(2) / 2 (HGPI)(3)	3 (HGPI)
Stage 2 Bucket	HGPI	3 (HGPI)(4)	4 (HGPI)
Stage 3 Bucket	HGPI	3 (HGPI)	4 (HGPI)

Note: Repair/replace cycles reflect current production hardware, unless otherwise noted, and operation in accordance with manufacturer specifications. They represent initial recommended intervals in the absence of operating and condition experience. For factored hours and starts of the repair intervals, refer to Figure 44.

CI = Combustion Inspection Interval
HGPI = Hot Gas Path Inspection Interval

(1) 3 (CI) for DLN / 4 (CI) for non-DLN

(2) 3 (HGPI) for 6BU with strip & recoat at first HGPI

(3) 2 HGPI for 6BeV

(4) 3 (HGPI) for current design only. Consult your GE Energy representative for replace intervals by part number.

Figure D-4. Estimated repair and replacement cycles

PG7001(EA) / PG9001(E) Parts

	Repair Interval	Replace Interval (Hours)	Replace Interval (Starts)
Combustion Liners	CI	4 (CI) / 6 (CI)(1)	4 (CI)
Caps	CI	4 (CI) / 6 (CI)(1)	4 (CI)
Transition Pieces	CI	4 (CI) / 6 (CI)(1)	4 (CI)
Fuel Nozzles	CI	4 (CI) / 6 (CI)(1)	4 (CI)
Crossfire Tubes	CI	1 (CI)	1 (CI)
Crossfire Tube Retaining Clips	CI	1 (CI)	1 (CI)
Flow Divider (Distillate)	CI	3 (CI)	3 (CI)
Fuel Pump (Distillate)	CI	3 (CI)	3 (CI)
Stage 1 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 2 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 3 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 1 Shrouds	HGPI	2 (HGPI)	2 (HGPI)
Stage 2 Shrouds	HGPI	3 (HGPI)	4 (HGPI)
Stage 3 Shrouds	HGPI	3 (HGPI)	4 (HGPI)
Stage 1 Bucket	HGPI	3 (HGPI)(2)(3)	3 (HGPI)
Stage 2 Bucket	HGPI	3 (HGPI)(4)	4 (HGPI)
Stage 3 Bucket	HGPI	3 (HGPI)	4 (HGPI)

Note: Repair/replace cycles reflect current production hardware, unless otherwise noted, and operation in accordance with manufacturer specifications. They represent initial recommended intervals in the absence of operating and condition experience. For factored hours and starts of the repair intervals, refer to Figure 44.

CI = Combustion Inspection Interval
HGPI = Hot Gas Path Inspection Interval

(1) 4 (CI) for DLN / 6 (CI) for non-DLN
(2) Strip and Recoat is required at first HGPI to achieve 3 HGPI replace interval for all E-Class.
(3) Uprated 7EA machines (2055 Tfire) require HIP rejuvenation at first HGPI to achieve 3 HGPI replace interval.
(4) 3 (HGPI) interval requires meeting tip shroud engagement criteria at prior HGP repair intervals. Consult your GE Energy representative for details.

Figure D-5. Estimated repair and replacement cycles

PG6101(FA): 6FA.01 Parts

	Repair Interval	Replace Interval (Hours)	Replace Interval (Starts)
Combustion Liners	CI	6 (CI)	5 (CI)
Caps	CI	6 (CI)	5 (CI)
Transition Pieces	CI	6 (CI)	5 (CI)
Fuel Nozzles	CI	3 (CI)	3 (CI)
Crossfire Tubes	CI	1 (CI)	1 (CI)
Crossfire Tube Retaining Clips	CI	1 (CI)	1 (CI)
End Covers	CI	6 (CI)	3 (CI)
Stage 1 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 2 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 3 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 1 Shrouds	HGPI	2 (HGPI)	2 (HGPI)
Stage 2 Shrouds	HGPI	2 (HGPI)	2 (HGPI)
Stage 3 Shrouds	HGPI	3 (HGPI)	3 (HGPI)
Stage 1 Bucket	HGPI	2 (HGPI)	2 (HGPI)(1)
Stage 2 Bucket	HGPI	1 (HGPI)(3)	3 (HGPI)(2)
Stage 3 Bucket	HGPI	3 (HGPI)(2)	3 (HGPI)(2)

Note: Repair/replace cycles reflect current production hardware, unless otherwise noted, and operation in accordance with manufacturer specifications. They represent initial recommended intervals in the absence of operating and condition experience. For factored hours and starts of the repair intervals, refer to Figure 44.

CI = Combustion Inspection Interval
HGPI = Hot Gas Path Inspection Interval

(1) GE approved repair operations may be needed to meet expected life. Consult your GE Energy representative for details.
(2) With welded hardface on shroud, recoating at 1st HGPI is required to achieve replacement life.
(3) Repair may be required on non-scalloped-from-birth parts. Redesigned bucket is capable of 3 (HGPI).

Figure D-6. Estimated repair and replacement cycles

PG6111(FA): 6FA.02 Parts

	Repair Interval	Replace Interval (Hours)	Replace Interval (Starts)
Combustion Liners	CI	2 (CI)	2 (CI)
Caps	CI	3 (CI)	2 (CI)
Transition Pieces	CI	3 (CI)	2 (CI)
Fuel Nozzles	CI	2 (CI)	2 (CI)
Crossfire Tubes	CI	1 (CI)	1 (CI)
Crossfire Tube Retaining Clips	CI	1 (CI)	1 (CI)
End Covers	CI	4 (CI)	2 (CI)
Stage 1 Nozzles	HGPI	2 (HGPI)	2 (HGPI)
Stage 2 Nozzles	HGPI	2 (HGPI)	2 (HGPI)
Stage 3 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 1 Shrouds	HGPI	2 (HGPI)	2 (HGPI)
Stage 2 Shrouds	HGPI	2 (HGPI)	2 (HGPI)
Stage 3 Shrouds	HGPI	3 (HGPI)	3 (HGPI)
Stage 1 Buckets	HGPI	3 (HGPI)	2 (HGPI)
Stage 2 Buckets	HGPI	3 (HGPI)	2 (HGPI)
Stage 3 Buckets	HGPI	2 (HGPI)	3 (HGPI)

Note: Repair/replace cycles reflect current production hardware, unless otherwise noted, and operation in accordance with manufacturer specifications. They represent initial recommended intervals in the absence of operating and condition experience. For factored hours and starts of the repair intervals, refer to Figure 44.

CI = Combustion Inspection Interval
HGPI = Hot Gas Path Inspection Interval

Figure D-7. Estimated repair and replacement cycles

PG7211(F): 7F.01 / PG9301(F): 9F.01 Parts

	Repair Interval	Replace Interval (Hours)	Replace Interval (Starts)
Combustion Liners	CI	6 (CI)	5 (CI)
Caps	CI	6 (CI)	5 (CI)
Transition Pieces	CI	6 (CI)	5 (CI)
Fuel Nozzles	CI	3 (CI)	3 (CI)
Crossfire Tubes	CI	1 (CI)	1 (CI)
Crossfire Tube Retaining Clips	CI	1 (CI)	1 (CI)
End Covers	CI	6 (CI)	3 (CI)
Stage 1 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 2 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 3 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 1 Shrouds	HGPI	2 (HGPI)	2 (HGPI)
Stage 2 Shrouds	HGPI	2 (HGPI)	2 (HGPI)
Stage 3 Shrouds	HGPI	3 (HGPI)	3 (HGPI)
Stage 1 Bucket	HGPI	2 (HGPI)	2 (HGPI)
Stage 2 Bucket	HGPI	3 (HGPI)(1)	3 (HGPI)(1)
Stage 3 Bucket	HGPI	3 (HGPI)(1)	3 (HGPI)(1)

Note: Repair/replace cycles reflect current production hardware, unless otherwise noted, and operation in accordance with manufacturer specifications. They represent initial recommended intervals in the absence of operating and condition experience. For factored hours and starts of the repair intervals, refer to Figure 44.

CI = Combustion Inspection Interval

HGPI = Hot Gas Path Inspection Interval

(1) With welded hardface on shroud, recoating at 1st HGPI is required to achieve replacement life.

Figure D-8. Estimated repair and replacement cycles

PG7221(FA): 7FA.01 / PG9311(FA): 9FA.01 Parts

	Repair Interval	Replace Interval (Hours)	Replace Interval (Starts)
Combustion Liners	CI	6 (CI)	5 (CI)
Caps	CI	6 (CI)	5 (CI)
Transition Pieces	CI	6 (CI)	5 (CI)
Fuel Nozzles	CI	3 (CI)	3 (CI)
Crossfire Tubes	CI	1 (CI)	1 (CI)
Crossfire Tube Retaining Clips	CI	1 (CI)	1 (CI)
End Covers	CI	6 (CI)	3 (CI)
Stage 1 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 2 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 3 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 1 Shrouds	HGPI	2 (HGPI)	2 (HGPI)
Stage 2 Shrouds	HGPI	2 (HGPI)	2 (HGPI)
Stage 3 Shrouds	HGPI	3 (HGPI)	3 (HGPI)
Stage 1 Bucket	HGPI	2 (HGPI)	2 (HGPI)(1)
Stage 2 Bucket	HGPI	2 (HGPI)	3 (HGPI)
Stage 3 Bucket	HGPI	3 (HGPI)(2)	3 (HGPI)(2)

Note: Repair/replace cycles reflect current production hardware, unless otherwise noted, and operation in accordance with manufacturer specifications. They represent initial recommended intervals in the absence of operating and condition experience. For factored hours and starts of the repair intervals, refer to Figure 44.

CI = Combustion Inspection Interval

HGPI = Hot Gas Path Inspection Interval

(1) GE approved repair operations may be needed to meet expected life. Consult your GE Energy representative for details.

(2) With welded hardface on shroud, recoating at 1st HGPI may be required to achieve replacement life.

Figure D-9. Estimated repair and replacement cycles

PG7231(FA): 7FA.02 Parts

	Repair Interval	Replace Interval (Hours)	Replace Interval (Starts)
Combustion Liners	CI	6 (CI)	5 (CI)
Caps	CI	6 (CI)	5 (CI)
Transition Pieces	CI	6 (CI)	5 (CI)
Fuel Nozzles	CI	3 (CI)	3 (CI)
Crossfire Tubes	CI	1 (CI)	1 (CI)
Crossfire Tube Retaining Clips	CI	1 (CI)	1 (CI)
End Covers	CI	6 (CI)	3 (CI)
Stage 1 Nozzles	HGPI	2 (HGPI)	2 (HGPI)
Stage 2 Nozzles	HGPI	2 (HGPI)	2 (HGPI)
Stage 3 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 1 Shrouds	HGPI	2 (HGPI)	2 (HGPI)
Stage 2 Shrouds	HGPI	2 (HGPI)	2 (HGPI)
Stage 3 Shrouds	HGPI	3 (HGPI)	3 (HGPI)
Stage 1 Bucket	HGPI	2 (HGPI)	2 (HGPI)(1)
Stage 2 Bucket	HGPI	1 (HGPI)(2)	3 (HGPI)(3)
Stage 3 Bucket	HGPI	3 (HGPI)	3 (HGPI)

Note: Repair/replace cycles reflect current production hardware, unless otherwise noted, and operation in accordance with manufacturer specifications. They represent initial recommended intervals in the absence of operating and condition experience. For factored hours and starts of the repair intervals, refer to Figure 44.

CI = Combustion Inspection Interval

HGPI = Hot Gas Path Inspection Interval

(1) Periodic inspections are recommended within each HGPI. GE approved repair operations may be needed to meet 2 (HGPI) replacement. Consult your GE Energy representative for details on both.

(2) Interval can be increased to 2 (HGPI) by performing a repair operation. Consult your GE Energy representative for details.

(3) Recoating at 1st HGPI may be required to achieve 3 HGPI replacement life.

Figure D-10. Estimated repair and replacement cycles

PG7241(FA): 7FA.03 Parts

	Repair Interval	Replace Interval (Hours)	Replace Interval (Starts)
Combustion Liners*	CI	4 (CI)	2 (CI)
Caps*	CI	4 (CI)	2 (CI)
Transition Pieces*	CI	4 (CI)	2 (CI)
Fuel Nozzles*	CI	4 (CI)	2 (CI)
Crossfire Tubes*	CI	1 (CI)	1 (CI)
Crossfire Tube Retaining Clips	CI	1 (CI)	1 (CI)
End Covers*	CI	4 (CI)	2 (CI)
Stage 1 Nozzles	HGPI	2 (HGPI)	2 (HGPI)
Stage 2 Nozzles	HGPI	2 (HGPI)	2 (HGPI)
Stage 3 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 1 Shrouds	HGPI	2 (HGPI)	2 (HGPI)
Stage 2 Shrouds	HGPI	2 (HGPI)	2 (HGPI)
Stage 3 Shrouds	HGPI	3 (HGPI)	3 (HGPI)
Stage 1 Bucket	HGPI	3 (HGPI)(2)	2 (HGPI)(4)
Stage 2 Bucket	HGPI	3 (HGPI)(1)	3 (HGPI)(1)
Stage 3 Bucket	HGPI	3 (HGPI)(3)	3 (HGPI)

Note: Repair/replace cycles reflect current production hardware, unless otherwise noted, and operation in accordance with manufacturer specifications. They represent initial recommended intervals in the absence of operating and condition experience. For factored hours and starts of the repair intervals, refer to Figure 44.

*12K Extended Interval Hardware
CI = Combustion Inspection Interval
HGPI = Hot Gas Path Inspection Interval

(1) 3 (HGPI) for current design. Consult your GE Energy representative for replacement intervals by part number.
(2) GE approved repair procedure required at first HGPI for designs without platform cooling.
(3) GE approved repair procedure at 2nd HGPI is required to meet 3 (HGPI) replacement life.
(4) 2 (HGPI) for current design with GE approved repair at first HGPI. 3 (HGPI) is possible for redesigned bucket with platform undercut and cooling modifications.

Figure D-11. Estimated repair and replacement cycles

PG9351(FA): 9FA.03 Parts

	Repair Interval	Replace Interval (Hours)	Replace Interval (Starts)
Combustion Liners	CI	5 (CI)	5 (CI)
Caps	CI	5 (CI)	5 (CI)
Transition Pieces	CI	5 (CI)	5 (CI)
Fuel Nozzles	CI	3 (CI)(1)	3 (CI)(1)
Crossfire Tubes	CI	1 (CI)	1 (CI)
Crossfire Tube Retaining Clips	CI	1 (CI)	1 (CI)
End Covers	CI	6 (CI)	3 (CI)
Stage 1 Nozzles	HGPI	2 (HGPI)	2 (HGPI)
Stage 2 Nozzles	HGPI	2 (HGPI)	2 (HGPI)
Stage 3 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 1 Shrouds	HGPI	2 (HGPI)	2 (HGPI)
Stage 2 Shrouds	HGPI	2 (HGPI)	2 (HGPI)
Stage 3 Shrouds	HGPI	3 (HGPI)	3 (HGPI)
Stage 1 Bucket	HGPI	2 (HGPI)(2)	2 (HGPI)(4)
Stage 2 Bucket	HGPI	3 (HGPI)(5)	3 (HGPI)(3)
Stage 3 Bucket	HGPI	3 (HGPI)(5)	3 (HGPI)

Note: Repair/replace cycles reflect current production hardware, unless otherwise noted, and operation in accordance with manufacturer specifications. They represent initial recommended intervals in the absence of operating and condition experience. For factored hours and starts of the repair intervals, refer to Figure 44.

CI = Combustion Inspection Interval
HGPI = Hot Gas Path Inspection Interval

(1) Blank and liquid fuel cartridges to be replaced at each CI
(2) 2 (HGPI) for current design with GE approved repair at first HGPI. 3 (HGPI) is possible for redesigned bucket with platform undercut and cooling modifications.
(3) Recoating at 1st HGPI may be required to achieve 3 HGPI replacement life.
(4) GE approved repair procedure at 1 (HGPI) is required to meet 2 (HGPI) replacement life.
(5) GE approved repair procedure is required to meet 3 (HGPI) replacement life.

Figure D-12. Estimated repair and replacement cycles

PG7251(FB): 7FB.01 Parts

	Repair Interval	Replace Interval (Hours)	Replace Interval (Starts)
Combustion Liners	CI	3 (CI)	3 (CI)
Caps	CI	3 (CI)	3 (CI)
Transition Pieces	CI	3 (CI)	3 (CI)
Fuel Nozzles	CI	2 (CI)(1)	2 (CI)(1)
Crossfire Tubes	CI	1 (CI)	1 (CI)
Crossfire Tube Retaining Clips	CI	1 (CI)	1 (CI)
End Covers	CI	3 (CI)	3 (CI)
Stage 1 Nozzles	HGPI	2 (HGPI)	2 (HGPI)
Stage 2 Nozzles	HGPI	2 (HGPI)	2 (HGPI)
Stage 3 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 1 Shrouds	HGPI	2 (HGPI)	2 (HGPI)
Stage 2 Shrouds	HGPI	2 (HGPI)	2 (HGPI)
Stage 3 Shrouds	HGPI	3 (HGPI)	3 (HGPI)
Stage 1 Bucket	HGPI	2 (HGPI)	1 (HGPI)
Stage 2 Bucket	HGPI	3 (HGPI)	3 (HGPI)
Stage 3 Bucket	HGPI	3 (HGPI)	3 (HGPI)

Note: Repair/replace cycles reflect current production hardware, unless otherwise noted, and operation in accordance with manufacturer specifications. They represent initial recommended intervals in the absence of operating and condition experience. For factored hours and starts of the repair intervals, refer to Figure 44.

CI = Combustion Inspection Interval
HGPI = Hot Gas Path Inspection Interval
(1) Blank and liquid fuel cartridges to be replaced at each CI

Figure D-13. Estimated repair and replacement cycles

PG9371(FB): 9FB.01 Parts

	Repair Interval	Replace Interval (Hours)	Replace Interval (Starts)
Combustion Liners	CI	4 (CI)	4 (CI)
Caps	CI	4 (CI)	4 (CI)
Transition Pieces	CI	4 (CI)	4 (CI)
Fuel Nozzles	CI	2 (CI)(1)	2 (CI)(1)
Crossfire Tubes	CI	1 (CI)	1 (CI)
Crossfire Tube Retaining Clips	CI	1 (CI)	1 (CI)
End Covers	CI	4 (CI)	4 (CI)
Stage 1 Nozzles	HGPI	1 (HGPI)(2)	1 (HGPI)(2)
Stage 2 Nozzles	HGPI	2 (HGPI)	2 (HGPI)
Stage 3 Nozzles	HGPI	3 (HGPI)	3 (HGPI)
Stage 1 Shrouds	HGPI	2 (HGPI)	2 (HGPI)
Stage 2 Shrouds	HGPI	2 (HGPI)	2 (HGPI)
Stage 3 Shrouds	HGPI	3 (HGPI)	3 (HGPI)
Stage 1 Buckets	HGPI	1 (HGPI)(2)	1 (HGPI)(2)
Stage 2 Buckets	HGPI	1 (HGPI)(2)	1 (HGPI)(2)
Stage 3 Buckets	HGPI	1 (HGPI)(2)	1 (HGPI)(2)

Note: Repair/replace cycles reflect current production hardware, unless otherwise noted, and operation in accordance with manufacturer specifications. They represent initial recommended intervals in the absence of operating and condition experience. For factored hours and starts of the repair intervals, refer to Figure 44.

CI = Combustion Inspection Interval
HGPI = Hot Gas Path Inspection Interval

(1) Blank and liquid fuel cartridges to be replaced at each CI

(2) 1 HGPI replacement interval for currently shipping units. Older units may have extended lives. Consult your GE Energy Services representative for unit specific recommendations.

Figure D-14. Estimated repair and replacement cycles

E) Boroscope Inspection Ports

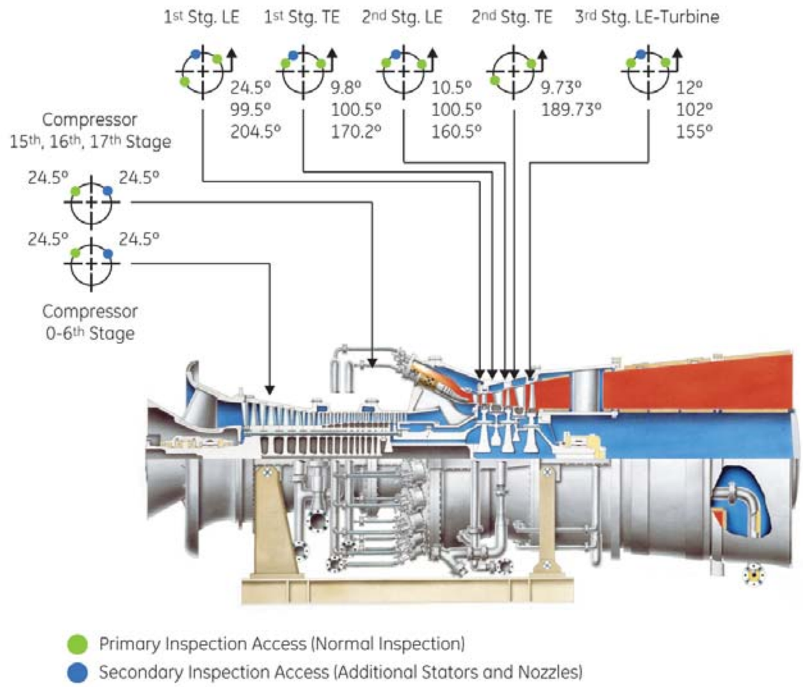

Figure E-1. Borescope inspection access locations for 6F machines

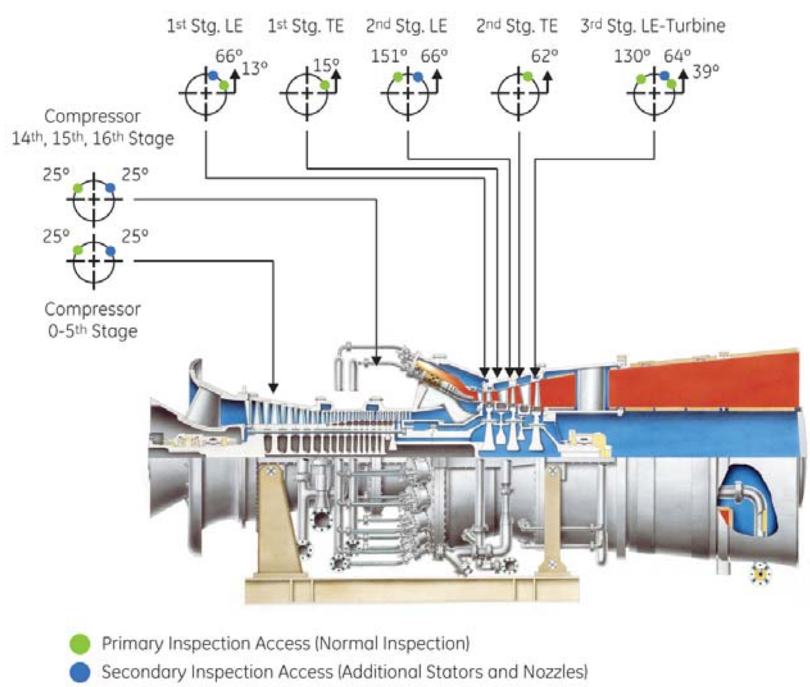

Figure E-2. Borescope inspection access locations for 7/9F machines

F) Turning Gear/Ratchet Running Guidelines

Scenario	Turning Gear (or Ratchet) Duration
Following Shutdown:	
Case A.1 – Normal. Restart anticipated for >48 hours	Until wheelspace temperatures <150F.[1] Rotor classified as unbowed. Minimum 24 hours.[2]
Case A.2 – Normal. Restart anticipated for <48 hours	Continuously until restart. Rotor unbowed.
Case B – Immediate rotor stop necessary. (Stop >20 minutes) Suspected rotating hardware damage or unit malfunction	None. Classified as bowed.
Before Startup:	
Case C – Hot rotor, <20 minutes after rotor stop	0–1 hour[3]
Case D – Warm rotor, >20 minutes & <6 hours after rotor stop	4 hours
Case E.1 – Cold rotor, unbowed, off TG <48 hours	4 hours
Case E.2 – Cold rotor, unbowed, off TG >48 hours	6 hours
Case F – Cold rotor, bowed	8 hours[4]
During Extended Outage:	
Case G – When idle	1 hour/day
Case H – Alternative	No TG; 1 hour/week at full speed (no load).[5]

(1) Time depends on frame size and ambient environment.
(2) Cooldown cycle may be accelerated using starting device for forced cooldown. Turning gear, however, is recommended method.
(3) 1 hour on turning gear is recommended following a trip, before restarting. For normal shutdowns, use discretion.
(4) Follow bowed rotor startup procedure. See Operation and Maintenance Manual.
(5) Avoids high cycling of lube oil pump during long outages.

Figure F-1. Turning Gear Guidelines

List of Figures

Revision History

9/89 Original

8/91 Rev A

9/93 Rev B

3/95 Rev C

- Nozzle Clearances section removed
- Steam/Water Injection section added
- Cyclic Effects section added

5/96 Rev D

- Estimated Repair and Replacement Cycles added for F/FA

11/96 Rev E

11/98 Rev F

- Rotor Parts section added
- Estimated Repair and Replace Cycles added for FA+E
- Starts and hours-based rotor maintenance interval equations added

9/00 Rev G

11/02 Rev H

- Estimated Repair and Replace Cycles updated and moved to Appendix D
- Combustion Parts section added
- Inlet Fogging section added

1/03 Rev J

- Off Frequency Operation section added

10/04 Rev K

- GE design intent and predication upon proper components and use added
- Added recommendation for coalescing filters installation upstream of gas heaters
- Added recommendations for shutdown on gas fuel, dual fuel transfers, and FSDS maintenance
- Trip from peak load maintenance factor added
- Lube Oil Cleanliness section added
- Inlet Fogging section updated to Moisture Intake
- Best practices for turning gear operation added
- Rapid Cool-down section added
- Procedural clarifications for HGP inspection added
- Added inspections for galling/fretting in turbine dovetails to major inspection scope
- HGP factored starts calculation updated for application of trip factors
- Turning gear maintenance factor removed for F-class hours-based rotor life
- Removed reference to turning gear impacts on cyclic customers' rotor lives
- HGP factored starts example added
- F-class borescope inspection access locations added
- Various HGP parts replacement cycles updated and additional 6B table added
- Revision History added

11/09 Rev L

- Updated text throughout
- Casing section added
- Exhaust Diffuser section added
- Added new Fig. 26: F-Class Axial Diffuser
- Added new Fig. 27: E-Class Radial Diffuser
- Revised Fig. 3, 5, 7, 8, 11, 19, 20, 23, 35, 37, 38, 40, 41, 42, 43, 44, E-1, and E-2
- Appendix D – updated repair and replacement cycles
- Added PG6111 (FA) Estimated repair and replacement cycles
- Added PG9371 (FB) Estimated repair and replacement cycles

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