IMIA – WGP 42 (05)

International Association of Engineering Insurers
38th Annual Conference – Moscow 2005

Maintenance and Overhaul of Steam Turbines

HMN Series Steam Turbine – Courtesy Siemens Power Corporation

Working Group

John Latcovich, The Hartford Steam Boiler Inspection & Insurance Company, Hartford, Connecticut (Chairman)
Thomas Åstrom, Pohjola, Helsinki
Peter Frankhuizen, Praevenio, Amsterdam
Seigou Fukushima, Tokyo Marine, Tokyo
Håkan Hamberg, If P&C, Sundsvall
Stefan Keller, Swiss National, Basel

Maintenance and Overhaul of Steam Turbines

Table of Contents

Table of Contents (Continued)

Executive Summary

Steam turbines provide a means of converting saturated, superheated, or supercritical steam from boilers or heat recovery steam generators (HRSG) into rotational torque and power. Consequently steam turbines are utilized to drive a variety of equipment types of numerous sizes and speeds in just about every industry segment including power generation, pulp and paper, iron and steel, combined heat and power, and chemical, oil and gas industries.

While there are substantial differences in the design, complexity, application, steam conditions, and size of steam turbines, they all are fundamentally the same. They perform the same function, utilize similar major components and supporting systems, and are subjected to the same failure mechanisms. To support reliable turbine operation, there needs to be an effective infrastructure in place for monitoring the operating conditions, water/steam quality, and health of the steam turbine, for having and using written operating/maintenance procedures, for utilizing a maintenance management system to schedule/track maintenance, and for conducting training for personnel on an ongoing basis.

There have been numerous causes of steam turbine failures worldwide. The highest frequency events have been loss of lube oil incidents while the highest severity events have been overspeed events. Typically, higher frequency and higher severity events have been blade/bucket failures, particularly in the low pressure (LP) section of the turbine where the blading experienced a number of failure mechanisms (stress corrosion cracking (SCC), erosion, foreign object damage (FOD)) which ultimately led to failure.

With regards to maintenance practices in North America and Europe, there are no regulatory maintenance practices or intervals specified for non-nuclear steam turbines regardless of the industry or application. As such, the frequencies and tasks are defined by the turbine manufacturers, consultants, industry organizations, plant personnel, plant process requirements, or insurers based on past experience. In Japan, however, there are regulatory requirements for periodic maintenance. However, regardless of the area of the world, the recommended scheduled maintenance requirements for steam turbines are quite similar. For establishing longer time intervals between major overhaul outages, there are a number of different approaches which are utilized today worldwide. Regardless of the approach, it is important that the methodologies effectively establish the overhaul intervals based on the highest risk portions of the steam turbine.

The technologies being incorporated into new steam turbines are more sophisticated, require operation at higher pressures and temperatures, and generally have smaller clearances to improve efficiency. While these technologies have not caused any large losses, the inherent risk exposures are increasing and the in-service experience with these technologies needs to be monitored.

In summary, maintenance tasks and frequencies should be prioritized towards the portions of the steam turbine that have the highest risk. This usually means protecting the steam turbine from overspeeds, water induction, loss of lube oil, corrosive steam, and sticking valves that could cause major damage to the turbine, and conducting internal inspections of the turbine flowpath, shells and rotors for failure mechanism damage (creep, erosion, corrosion, fatigue, thermal fatigue, SCC) in order to detect the damage early enough to prevent a subsequent major failure.

1. Introduction

Steam turbines are utilized in numerous industries to drive boiler fans, boiler feed and water pumps, process and chiller compressors, blast furnace blowers, paper mill line shafts, sugar mill grinders, and generators in a variety of industries and applications. Consequently, steam turbines can range from being small and simple in design/construction to large, highly complex designs/arrangements consisting of multiple sections and multiple shafts.

Specifying the desired maintenance and overhaul intervals for steam turbines, therefore, has to take into account the design/construction of the turbine as well as the industry and application utilizing the turbine. Besides the configuration and industry associated with the steam turbine, the infrastructure for monitoring, operations and maintenance including specific practices, and steam quality can have a major effect on the reliability of steam turbines regardless of the industry or application.

In the next several sections of this paper, several pertinent aspects of steam turbines will be addressed. The discussions have been organized in a sequence beginning with steam turbine component characteristics, failure mechanisms, arrangements and applications. These discussions are followed by what infrastructures should be in place to operate and maintain steam turbines, what has failed based on past experience, and what maintenance should be conducted to minimize the risk of failure. And lastly, the discussions include what should be taken into account for determining longer major overhaul intervals and what effects the new steam turbine technologies may have on scheduled maintenance and overhaul intervals.

2. Steam Turbine Component Characteristics, Failure Mechanisms, Arrangements and Applications

Steam turbines are fundamentally the same regardless of whether they drive a simple 500 shaft horsepower (SHP) fan or drive a 1,000 MW generator. In all cases, steam is expanded through rows of stationary and rotating blading which convert the energy in the steam into mechanical energy. While the functions are the same for all steam turbines, the designs are sufficiently different to necessitate brief discussions on the important components, their characteristics and failure mechanisms, and how they are arranged or organized as these attributes do affect steam turbine maintenance tasks and frequencies.

2.A Turbine Component Characteristics and Failure Mechanisms

2.A.1 Steam Turbine Blading

Steam turbines produce power by converting the energy in steam provided from a boiler or heat recovery steam generator (HRSG) into rotational energy as the steam passes through a turbine stage. A turbine stage normally consists of a row of stationary blading and a row of rotating blading. The purpose of the stationary blading is to direct the flow of the passing steam to the rotating blading at the proper angle and velocity for the highest efficiency and extraction of power. The purpose of the rotating blading is to convert the directed mass flow and steam velocity into rotational speed and torque. Stationary blading may be referred to as nozzles, vanes, stators, partitions, and stationary blading while rotating blades may be referred to as buckets, blades, and rotating blading. A turbine may have a single row or stage of stationary and rotating blading or may have multiple rows or stages of blading.

Steam turbine blading have different shapes which are referred to as either impulse blading or reaction blading. Impulse blading is characterized by high velocity fluids entering the turbine blade, by a blade profile that efficiently turns the direction of the fluid with little pressure change, and by decreasing the velocity of the fluid as it leaves the blade to extract energy. Typical impulse blades are crescent or U-shaped and may not always be symmetrical.

Reaction blading is characterized by high velocity fluids entering the turbine blade, but not as high as impulse velocity levels, by a blade profile that efficiently allows the fluid to expand while passing through the blade, and by decreasing both the velocity and pressure of the fluid as it exits from the blade to extract energy. Typical reaction blading has tear-drop shaped leading edges with a tapered thickness to the trailing edge. The blades may have twist to their shape which may range from low amounts of twist or reaction at the base of the blade to high twist or reaction at the tip of the blade.

Impulse type blading is typically utilized in the high pressure or front sections of the steam turbine while reaction blading is utilized in the lower pressure or aft sections of the turbine. Many of today's new steam turbines, however, are utilizing reaction blading in all stages of the turbine including the high pressure sections. Regardless of the blading type, the blade tips may be covered with bands peened to their tips which connect several blades together in groups, or the blades may have integral shrouds which are part of the blades, or may have no tip cover bands or shrouds (free standing). The blade shrouds and cover bands are utilized to keep the passing steam from leaking over the tip of the blades which reduces efficiency and power output and to reduce or dampen the vibration characteristics of the blading. Both stationary and rotating blading can have shrouds or covers depending on the turbine design. The number of blades in a group that are covered by shrouds is dependent upon the vibration characteristics of the specific machine. For some designs, thick wires (called tie wires) are brazed into or between blades to dampen the vibration levels of the blades or groups of blades. In other cases, the tie wires are installed in the blade tips particularly in large blades in the last stages of turbines. And for some blade designs, interlocking tip shrouds (z-shaped) and midspan snubbers (contact surfaces) are utilized to dampen blade vibration, particularly for long last stage turbine blades.

Steam turbine blading can be subjected to several failure mechanisms in service. These mechanisms are indicated in Table 1 along with the resultant damage and typical causes of failure***. For steam turbines to operate with high reliability and availability, the ability to regularly inspect and assess the steam blading condition is important as any of the failure mechanisms in Table 1 can lead to failure if left undiagnosed or neglected.***

Table 1 – Steam Turbine Blading Failure Mechanisms

Failure Mechanism	Resultant Damage	Cause(s) of Failure
Corrosion	Extensive pitting of airfoils, shrouds, covers, blade root surfaces	Chemical attack from corrosive elements in the steam provided to the turbine
Creep	Airfoils, shrouds, covers permanently deformed	Deformed parts subjected to steam temperatures in excess of design limits
Erosion	Thinning of airfoils, shrouds, covers, blade roots	1) Solid particle erosion from very fine debris and scale in the steam provided in the turbine 2) Water droplet erosion from steam which is transitioning from vapor to liquid phase in the flowpath
Fatigue	Cracks in airfoils, shrouds, covers, blade roots	1) Parts operated at a vibratory natural frequency 2) Loss of part dampening (cover, tie wire, etc.) 3) Exceeded part fatigue life design limit 4) Excited by water induction incident – water flashes to steam in the flowpath
Foreign/Domestic Object Damage (FOD/DOD)	Impact damage (dents, dings, etc.) to any part of the blading	Damage from large debris in steam supplied to the turbine (foreign) or damage from debris generated from an internal turbine failure (domestic) which causes downstream impact damage to components
Stress Corrosion Cracking (SCC)	Cracks in highly stressed areas of the blading	Specialized type of cracking caused by the combined presence of corrosive elements and high stresses in highly loaded locations
Thermal Fatigue	Cracks in airfoils, shrouds, covers, and blade roots	Parts subjected to rapidly changing temperature gradients where thick sections are subjected to high alternating tensile and compressive stresses during heat-ups and cooldowns or when a water induction incident occurs where the inducted cool water quenches hot parts

2.A.2 Discs, Rotors, Shafts, Blade Rings, Shells, and Diaphragms

To transmit the torque produced in each stage of the turbine, the rotating blading is fastened to discs or wheels through a specially designed attachment shape at the blade base or root. The root shape may be fir-tree, T-slot, or semi-circular fir-tree shaped or may use multiple pins to hold the blades to the discs. The turbine discs may be shrunk fit onto a shaft with an anti-rotation key or the discs may have been forged with the shaft as an integral assembly. The output shaft from the shrunk fit or integral disc rotor is then connected to the driven equipment through a flange connection or flexible coupling.

Similarly, stationary blading roots may be attached to slots in shells, casings, or blade rings or where the stationary blading is welded to support rings to create a stationary blading assembly referred to as a diaphragm. Depending on the pressure and temperature of the steam to the turbine, there may be dual sets of shells or casings; an inner shell which holds the stationary blading and an outer shell which acts as pressure boundary for the turbine as well as accommodating attachment of blade rings.

The mass and thermal inertial of steam turbine rotors and shells can be quite large. As such, the temperature gradients the rotors and shells can encounter during starting and transients need to be controlled carefully otherwise there can be serious rubs between the rotating and stationary parts and/or there can be extensive distortion of rotors and/or shells when the gradients are too large or occur too fast.

Steam turbine discs, rotors, shafts, shells, blade rings, and diaphragms are subjected to the same failure mechanisms and causes that apply to steam turbine blading. It is not uncommon to encounter permanent deformation (creep), fatigue cracks (thermal and vibratory), and stress corrosion cracking in discs, rotors, shells, and diaphragms. Unlike blading, the mechanisms may take longer for the resultant damage to become detectable as these parts tend to be more robust in size.

2.A.3 Rotor Forgings with Center Bores

Integrally forged steam turbine rotors manufactured in the past two decades have not had bores machined in the center of the rotor. The improvements in steel refining and forging manufacturing have not necessitated the need to remove impurities and poorly forged material that accumulated in the center of older rotors. ***The presence of the center bore results in a high stress in the bore that requires periodic ultrasonic (UT) and eddy current (ET) inspection for cracks.***

Because of the quality of some of the early forgings, cracks have been found that require internal machining of the bore to remove the affected material. It has not been uncommon to find a few hundred thousand indications during UT inspection that may require additional analyses to determine if the indications are cracks and if they are connected to each other, potentially resulting in a unsafe condition. The improvements in UT inspection instrumentation and techniques have also resulted in finding new numbers of defects that were not detectable with older UT technologies. On the positive side, the presence of the center bore does allow for UT inspection of rotor wheels and blade slots from underneath.

2.A.4 Bearings and Lubrication Systems

As with most rotating machinery, bearings are utilized to support the turbine rotor inside housings installed in the turbine shells. Depending on the size and number of stages of the steam turbine, different types of bearings may be utilized. It is common for smaller steam turbines to utilize rolling element bearings while larger turbines will utilize journal and multi-pad thrust bearings. Regardless of the type of turbine, there needs to be a complete lubrication system that reliably provides clean, cool lube oil to the turbine bearings. For many large steam turbines, shaft lift oil systems are utilized to lift the shaft in their journal bearings during starting and to keep the shaft lubricated during coast down of the turbine rotor after steam to the turbine is shut off. For some turbines, lube oil (usually mineral oil) is utilized to power servomotors and actuators for stop and control valves. In other cases, hydraulic fluids (usually phosphate-ester type fluids), which can operate at higher pressures and temperatures without ignition, are utilized to provide the required power for the valves.

Properly designed and maintained lube oil or hydraulic fluid systems are extremely important. Most oil systems, as a minimum, need to include an oil reservoir with level indication, filters and separators (particulate and water removal), pumps (primary and emergency backup that are independent of the primary pump system), pressure switches or sensors to detect loss of oil pressure, and heat exchangers to cool the oil. Of most concern is protecting the turbine from loss of lube oil incidents which may involve the loss of oil pressure detectors (pressure switches and controls) or backup lube oil pump(s) and/or their starting logic not working properly.

Since oil is utilized to lubricate and cool turbine bearings (and gearbox gears and bearings, if present) and actuate major turbine valves, it is important that the oil be free of dirt, moisture, foaming, and any contaminants which would cause damage to bearings, servomotors, and valve actuators. Some contaminants are removed by filters, but removal of water requires water separators, oil purifiers, or centrifuge type filter systems. Oil coolers can also be a source of water as leaks tend to flow from higher pressure (water) to the lower pressure oil system in the cooler. Oil does oxidize in the presence of water and will have a limited life. As such, conducting frequent sampling of lube oil and hydraulic fluids for particulates, water, contaminants, and remaining life is important. ***The reliability of the lube oil system is important as loss of lube incidents have been both frequent and severe events for all sizes of turbines. As such, periodic checks of loss of lube protection devices and logic need to be conducted***.

2.A.5 Steam and Oil Seals

In order to keep the steam from going around the stationary and rotating blading, steam turbines utilize seals to keep the steam confined to the flowpath. Depending on the size and type of steam turbine, various types of steam seal designs (carbon rings, labyrinth, retractable labyrinth, brush) may be utilized. These systems are usually pressurized with steam to minimize the pressure differential across these seals so that leakage from the higher pressure parts of the turbine is less likely to occur. Similar type seals are utilized to keep bearing oil confined to the bearing housing. As such, seal systems may have filters, pressure regulators, coolers, and the like to maintain a seal pressure as required. ***Severe rubbing of new seals after overhaul or during transients operation, particularly starting, continues to cause steam turbine forced outages.***

2.A.6 Stop, Trip & Throttle, and Intercept Valves

Important to any turbine is the ability to start and stop the machine under normal (controlled) and emergency conditions. For steam turbines, being able to shut off the steam supply quickly and reliably is required. This is normally accomplished by either main steam (MS) stop valves or trip and throttle (T&T) valves which are usually installed in the inlet piping to the steam turbine or on the turbine shell. The valves are designed to be leak tight otherwise any steam leakage may keep the turbine turning at low speed after shutdown or causing an overspeed because the valve did not close completely after a shutdown or trip.

For most applications, actuators for these valves are powered by high-pressure hydraulic system fluid or lube system oil. Hydraulic or lube system pressure powers servomotors to open the valves while loss of oil pressure results in spring-load closing of the valve in a fail-safe condition (closed). For some old and small steam turbines, the stop valve may be a manual valve with a large handwheel. The same valve may also be used for starting the unit. In addition, there may be hand operated valves mounted in the nozzle inlet for manually increasing steam to the turbine.

For reheat type steam turbines, which direct steam back to a boiler superheater section for reheating after going through the high pressure section of the turbine, there are additional valves installed between the high pressure section and subsequent section of the turbine. Reheat stop valves are used for leak tight protection but a faster active valve called an intercept valve is installed in series or combination with the reheat stop valves in order to prevent overspeeds. The valves also open with oil pressure and are spring-loaded closed when oil pressure is reduced to zero under trip and overspeed conditions.

These valves provide fundamental overspeed protection to the steam turbine and need to be tested, inspected, and overhauled routinely as contaminants in the steam, wear of mating valve parts, or damaged valve seats can cause sticking or leaking of these valves in service.

2.A.7 Governor/Control Valves

Control valves are provided on the turbine shell to regulate the flow of steam to the turbine for starting, increasing/decreasing power, and maintaining speed control with the turbine governor system. Several different valve arrangements are utilized. These include a single inlet valve with separate actuator, cam lift inlet valve assemblies, and bar lift inlet valve assemblies. The valve assemblies are normally mounted onto a steam chest that may be integral to the shell or bolted to it. The cam lift valve arrangement utilizes cams, bearings, and bushings which are mounted on camshaft to regulate the position of each valve. A hydraulic servomotor drives a rack and pinion connection to the camshaft to indicate the position desired by the governor. In the bar lift valve arrangement, a hydraulic cylinder lifts all of the valves attached to the bar together, but the collars on each valve stem are set at different heights and opening sequencing for admitting steam during starting and load changes. ***These valves need to be cycled routinely to minimize the potential for the valves to stick. When the valves stick open or closed, the turbine is put into jeopardy as a result of losing the ability to control the turbine (i.e., increase or reduce load).***

2.A.8 Admission, Extraction, and Non-Return Valves (NRV)

In addition to the traditional stop and control valves, many steam turbines have additional ports installed on the turbine to admit or extract steam. Steam turbines designed to admit steam not only at the turbine inlet but also at a lower pressure locations in downstream sections of the turbine are referred to as admission turbines. These turbines are utilized primarily in applications (steel mills, paper mills, combined cycle plants with triple pressure HRSG's) where additional steam flow at lower pressures is available to make additional power.

In addition to providing additional sources of steam to the turbine, the turbine can also be a source of steam for facility services at various pressures and flows. Turbines with this kind of capability are referred to as extraction turbines and may be described by the number of extractions (single, dual, etc.). Steam is taken from the turbine at various stages to match with the facility's pressure and flow requirements. The extractions can be categorized as controlled or uncontrolled, as well as automatic or manual. Some extractions are utilized for feedwater heating. The extraction control valves typically have two functions; to regulate the steam flow externally and to maintain the extraction steam pressure constant. The valves are hydraulically opened and spring-loaded shut. They are, however, not designed to be leak tight and will typically pass 5% steam flow in the closed position.

Non-return valves (NRV) or check valves are normally installed downstream of the controlled and uncontrolled (i.e., no regulating or control valve) extraction connections to the turbine. The function of the valves is to permit flow of extraction steam in the outgoing direction and prohibit backward flow into the turbine when turbine extraction pressure is lower than the lines it feeds. The valves are designed to be spring-loaded shut when there is no extraction pressure but they also have an air or hydraulically assisted actuator to close the valve when the systems are pressurized. ***Malfunctioning of extraction NRV's is the primary cause of overspeed damage during turbine shutdown. As such, these valves need to be tested, inspected, and overhauled on a frequent basis.***

2.A.9 Steam Line Connections and Drains

Proper connections and support of the steam lines to the turbine are important as well as the steam drains. If the steam supply lines are putting a load on the turbine, it is likely to cause the turbine to vibrate and will cause mechanical distress to the attachment locations. Similarly, when steam turbines are started, there is a warm-up time to heat the turbine to the proper temperature level before admitting full starting steam. Removal of condensed steam from the stop valve and T&T valves, the turbine shells, and any sealing steam locations during this period of operation is important to prevent damage to the turbine. As such, low point drains, steam traps and drain valves, vents, and the like need to be functioning properly and piping runs orientated so that the water drains out. ***When drain systems are not operating properly, the potential for encountering thermally distorted rotors (bowed) and shells (humped) will be high.***

2.A.10 Turbine Overspeed Protection and Trip Logic

The most destructive event for a steam turbine is an overspeed event as the steam turbine and its driven equipment are usually catastrophically damaged. These events, while infrequent, continue to occur on both small and larger steam turbines regardless of the vintage, technology level, application, or type of control system (digital, analog, hydro-mechanical, mechanical) associated with the steam turbine.

A steam turbine may utilize a mechanical overspeed protection system, electronic overspeed protection system, or combination of systems to maximize protection. The mechanical overspeed device consists of a spring-loaded piston mounted in the turbine shaft at the front of the turbine. When turbine speed reaches an overspeed condition (i.e., 10% above running speed), the piston pops out and hits an oil dump valve lever which causes depressurization of the oil supply to the stop, trip and throttle, and intercept valves. This results in all stop and intercept valves immediately closing. Many mechanical systems also utilize a flywheel ball governor driven by the turbine shaft. Any change in governor position is converted to a change in oil pressure to the turbine control valve servomotor or actuator. Under overspeed conditions, the flywheel governor will hit the oil dump valve lever to close the steam stop valve.

With electronic systems, numerous magnetic speed pickups are installed on the turbine shaft. The turbine control system and software logic will electronically open the oil dump valve to depressurize the oil system and close all stop and intercept valves. There are various versions of electronic overspeed systems in service. Some include both primary and backup (emergency) systems that operate independently. Some include test switches to test the primary system for proper operation without actually tripping the turbine. For most turbines the overspeed protection system will also cause or command the turbine control valves to close as well. Because the control valves are not leak tight by design and their closure rate is much slower than stop and intercept valves, they are not considered to provide any overspeed protection.

In addition to the type of overspeed protection provided, the trip logic utilized by the control system to open the circuit breaker associated with the steam turbine's generator does have some effect on the performance of the protection. Typically, two trip schemes are utilized; sequential tripping and simultaneous tripping. Sequential tripping is when the steam turbine is always tripped first and the generator circuit breaker opens when the turbine speed and decaying power has decreased sufficiently to cause the generator reverse power relay to open the breaker. The method is typically utilized with large steam turbines operating at high steam inlet pressures and temperatures where it is desired to dissipate the energy in the turbine before opening the breaker to minimize the overspeed level on shutdown.

Simultaneous tripping is utilized when both the turbine stop or trip and throttle valve and the generator circuit breaker are opened at the same time, regardless of whether the turbine or generator protection system initiated the trip. This type system is utilized successfully on small to medium size steam turbines where the steam pressures and temperatures are low and there is little steam volume in the turbine to cause an increase in speed on shutdown. ***Regardless of the type of overspeed and trip protection systems provided, the system needs to be regularly tested by simulation and by actual testing of the complete system.***

2.B Steam Turbine Arrangements and Applications

<u>2.B.1 Type of Steam</u>

The steam utilized in steam turbines can be in three different states: saturated, superheated, and supercritical. Saturated steam is produced when you heat water to the boiling point or vaporization temperature for a given pressure. Under those conditions, you have very hot water and a steam vapor that is given off at the water interface, similar to what happens in a tea pot. However, for steam turbines, the boiling occurs in the boiler steam drum where the steam is separated from the liquid water that it came from. Depending on the pressure and temperature of the water being heated, the steam may still contain a portion of entrained water unless it is heated further to vaporize the remaining water content. Steam turbines do not like water in their steam so the steam is heated until all of the remaining water has vaporized.

Saturated steam may be heated to a higher temperature at the same pressure in other boiler sections referred to as superheaters or reheaters. Saturated steam heated to these higher temperatures is then referred to as superheated steam. Steam turbines which utilize superheated and saturated steam are often referred to as subcritical steam turbines.

If the pressure of the superheated steam is increased further until the thermodynamic critical point of water is reached (221 bar/3,205 psi), then the steam is referred to as supercritical steam. This steam has the characteristic of passing from a liquid (water) to a vapor (steam) state without going through an intermediate liquid and vapor phase. This means a boiler drum is not needed as the heated water directly converts to vapor with no moisture to separate or reheat. Turbines utilizing this type of steam are referred to as supercritical turbines. If the pressure of the steam is increased to 370 bar (5,365 psi), the plants are referred to as ultra-supercritical plants.

As would be expected, as the temperature and pressure of steam increase, the complexity, materials, and the costs of the steam turbines will increase accordingly. Typically, most smaller steam turbines utilize saturated steam. Most industrial and power plant applications use superheated steam, and most advanced power plants are moving towards supercritical steam. The supercritical units have higher efficiencies, produce less emissions, need less fuel, but tend to require more advanced and thicker materials to deal with both the higher pressures (370 bar/5,365 psi) and temperatures (720°C/1,328°F). Of course, the costs are higher as well.

There are a number of typical inlet pressures and temperatures that steam turbines are designed to utilize. The approximate ranges of steam inlet conditions for various size units can be arbitrarily categorized based on what has been installed in industry. These are listed below noting that there is some overlap between conditions.

- Small Units (0.5 - 2 MW): 150-400 psi/500-750°F (10-30 bar/260-400°C)
- Medium Units (1.5 - 10 MW): 400-600 psi/750-825°F (10-42 bar/400-440°C)
- Large Units (4 - 100 MW): 600-900 psi/750-900°F (42-62 bar/400-482°C)
- Large Units (10-1,000 MW): 900-2,400 psi/825-1,050°F (62-166 bar/440-566°C)
- Supercritical Units (>200 MW): 3,625-5,365 psi/1,010-1,328°F (250-370 bar/ 540-720°C)

2.B.2 Exhaust System Configuration

The exhaust of the turbine can be designed for two different pressure levels. If the exhaust pressure of the turbine is designed to be near atmospheric pressure (i.e., a few inches of Mercury absolute), the turbine type is referred to as a condensing turbine. This is because the low pressure exhaust steam enters the condenser for conversion into water, which is pumped to the plant's condensate and feedwater systems. The condensing steam turbine exhaust may be in the vertical or axial (horizontal) direction. This type of turbine results in maximizing the expansion ratio across the turbine and requires larger last stage turbine blades as a result of the low pressures in the later stages of the turbine. If the exhaust pressure of the turbine is designed for a higher pressure (i.e., 3.5 bar/50 psi), the turbine is referred to as a backpressure turbine. In these types of applications, the steam turbine is being used as a pressure reducing station which can make power; however, the higher pressure exhaust steam is being used for other purposes in the facility. In this case, the exhaust connection to the turbine will be a pipe rather than ducting leading to a condenser, consequently the last stage blades will be smaller. Figure 1 shows examples of small condensing and backpressure steam turbines.

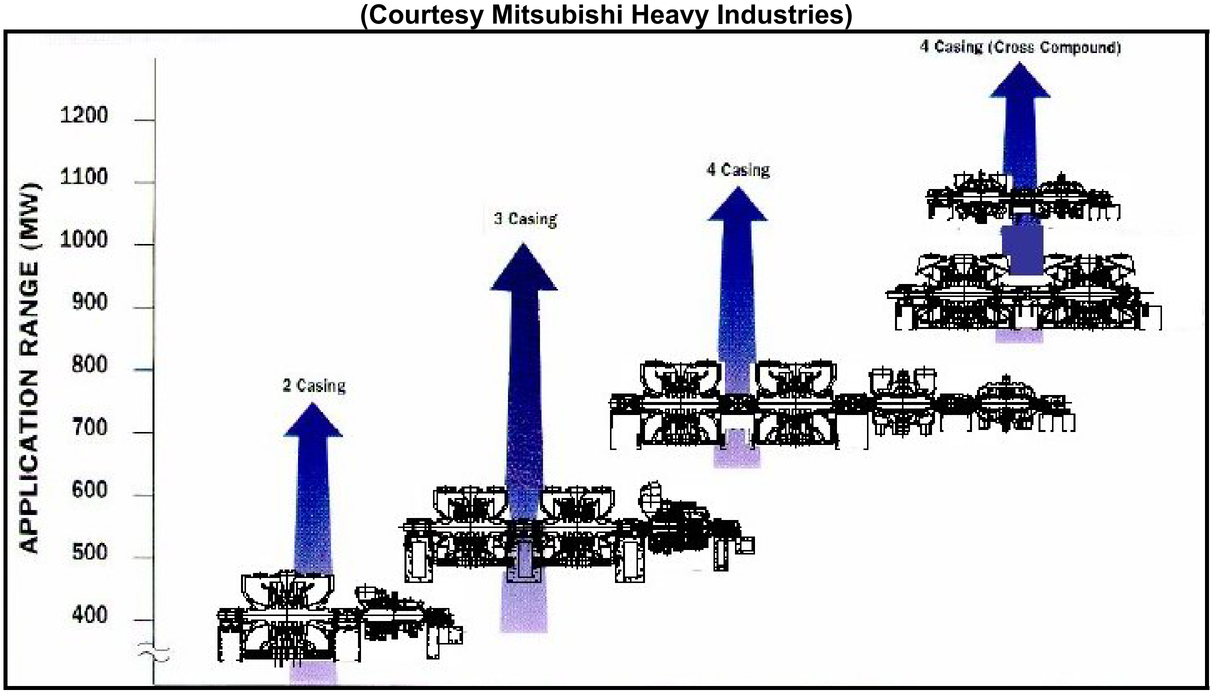
Figure 1 – 2.5 MW Condensing and 15 MW Backpressure Steam Turbines (Courtesy Elliott Company and Alstom Power)

2.B.3 Grouping and Number of Turbine Stages

Turbines are often described by the number of stages. For example, single stage turbines are usually small units that drive pumps, fans, and other general purpose equipment in a facility. For medium size steam turbines that drive air conditioning chillers or generators, 4 to 10 stages may be utilized. In large size units, there may be 12 to 40 stages driving generators or other equipment. These stages may be grouped into different sections of the turbine. The section with the highest pressure levels is called the high pressure (HP) section. The intermediate pressure (IP) section has the mid-level pressure levels. The low pressure (LP) section has the lowest pressure levels and discharges to the condenser or backpressure system. The turbine sections can be packaged into separate sections in a single turbine casing, into separate casings for each section, or in combination (HP/IP turbines in one casing and LP turbine in another). In addition, in many LP turbines and some HP and IP turbines, there are two turbines connected together in the same casing but in opposing directions to balance the thrust loads. Flow to these turbines is through the center of the casing and exits from each end of the turbine. These are referred to as turbines with double flows (i.e., opposing flowpaths on same shaft).

The MW rating of the steam turbine, however, may not be indicative of the number of sections or casings which make up the turbine. This is exemplified in Figure 2 where a 750 MW turbine could consist of 2, 3 or 4 casings. Of course the fewer number of casings and stages for the same steam conditions results in high loadings and larger size blading for these model turbines, particularly in the last stage. The selection of which configuration is utilized is dependent on economics (cost and efficiency) and customer desires.

Figure 2 – Number of Turbine Casings as a Function of Steam Turbine Size (Courtesy Mitsubishi Heavy Industries)



Consistent with the variation in the number of turbine casings, the last stage blades in the LP section, which is the largest blade in the turbine, may range in size and materials over a broad range. Figure 3 shows a typical suite of blade sizes that a manufacturer may utilize in their steam turbines. Several manufacturers are now utilizing titanium material for the last stage blades because of the lighter weight and improved corrosion resistance as compared to steel blades. Unfortunately, whether made from titanium or steel, these large blades are usually the most expensive in the turbine and the most likely to fail with time.

Figure 3 – Typical LP Turbine Last Stage Blade Sizes (Courtesy Mitsubishi Heavy Industries)

630 mm	**750 mm**	**970 mm**	**1010 mm**	**1140 mm**	**1040 mm**	**1179 mm**	**1370 mm**
(25 inch)	**(29.5 inch)**	**(33 inch)**	**(40 inch)**	**(45 inch Ti)**	**(41 inch)**	**(46 inch)**	**(54 inch)**

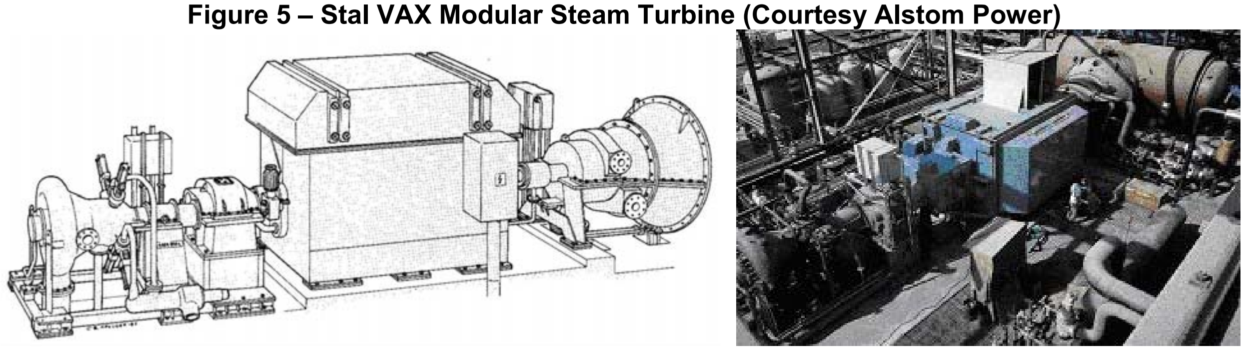
2.B.4 Turbine Arrangement

In most cases, steam turbines and the generators they drive are laid out in sequence, meaning that the casings and shafts of all of the turbine sections and generator are in a single line. This is referred to as a tandem compound layout or arrangement. In some cases, the casings and shafting are laid out with two parallel shafting arrangements. These are referred to as cross compound arrangement. These units are characterized by the HP and IP turbines driving one generator and the LP turbine driving another generator. The steam for the LP turbine comes from a cross connection from the IP turbine exhaust. This is exemplified in Figure 4 where the HP and IP turbines and their generator make up the left drive train while the 2 LP turbines and their generator make up the right drive train. Regardless of the two parallel shafting arrangement, the unit has to run as if the systems were all directly connected together.

Figure 4 – 1,050 MW Cross Compound Steam Turbine Generator (Courtesy Mitsubishi Heavy Industries)

For some steam turbine designs, the turbine sections are mounted on opposite sides of the generator. An example of a Stal VAX modular steam turbine generator design is shown in Figure 5. In this turbine design, the HP turbine section is on the left of the generator and the LP turbine is mounted on the other side of the generator. A reduction gearbox is provided to reduce HP turbine speed to the generator. Stal also designed radial turbines where there are no stationary blading but rather counter rotating blading that connect to two separate generators.

Figure 5 – Stal VAX Modular Steam Turbine (Courtesy Alstom Power)



While the exhaust arrangement, steam inlet conditions, and turbine stages and/or blade size can characterize a turbine, so can the operating speed. Most larger steam turbines and older turbines run at 3,000 (50 Hz) or 3,600 (60 Hz) RPM. The LP turbines and generators with cross compound units typically run at half speed – 1,500 (50Hz) and 1,800 (60 Hz) RPM. All of these turbines connect directly to the generator for operation at this speed. Small, medium and lower-end large turbines run at higher speeds (5,000 to 12,000 RPM). This necessitates the use of a speed reduction gearbox to match the generator design speeds. In non-generator drive applications, the steam turbines may be run at higher speeds with or without a gearbox to match the driven speed of compressors, pumps, fans, line shafts, and other equipment.

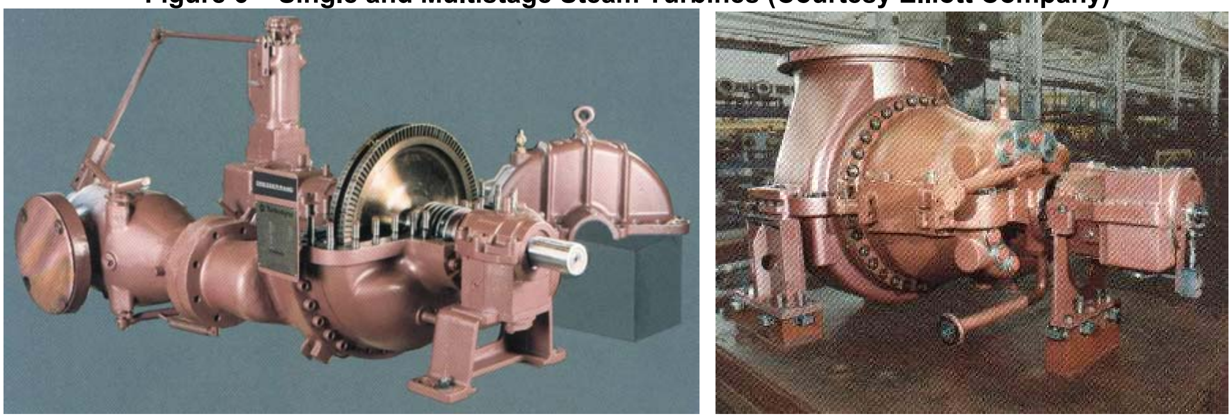
2.B.5 Single Stage Small Steam Turbines

A typical single stage turbine is shown in the left side of Figure 6. These units typically consist of a double row of stationary and rotating blading, wheels keyed and shrunk onto shaft, anti-friction thrust and radial journal bearings, carbon shaft seals, overspeed trip bolt, mechanical governor, and housings. Because these turbines run low pressure and temperature steam, they are usually constructed of less sophisticated and lower cost materials. These types of units are utilized to drive boiler fans, water pumps, boiler feed pumps, and generators in a variety of industries.

2.B.6 Multistage Medium Size Steam Turbines

The typical construction of a multistage unit with nine stages is shown in the right side of Figure 6. These type of units consist of an initial impulse stage followed by several reaction stages, wheels shrunk onto a shaft, tilting pad thrust and radial journal bearings, labyrinth shaft seals, overspeed trip device, and casing. These may be used for driving line shafts in paper mills, chiller compressors for building air conditioning, small centrifugal and reciprocating compressors in the oil and gas industry, and generators in all industries.

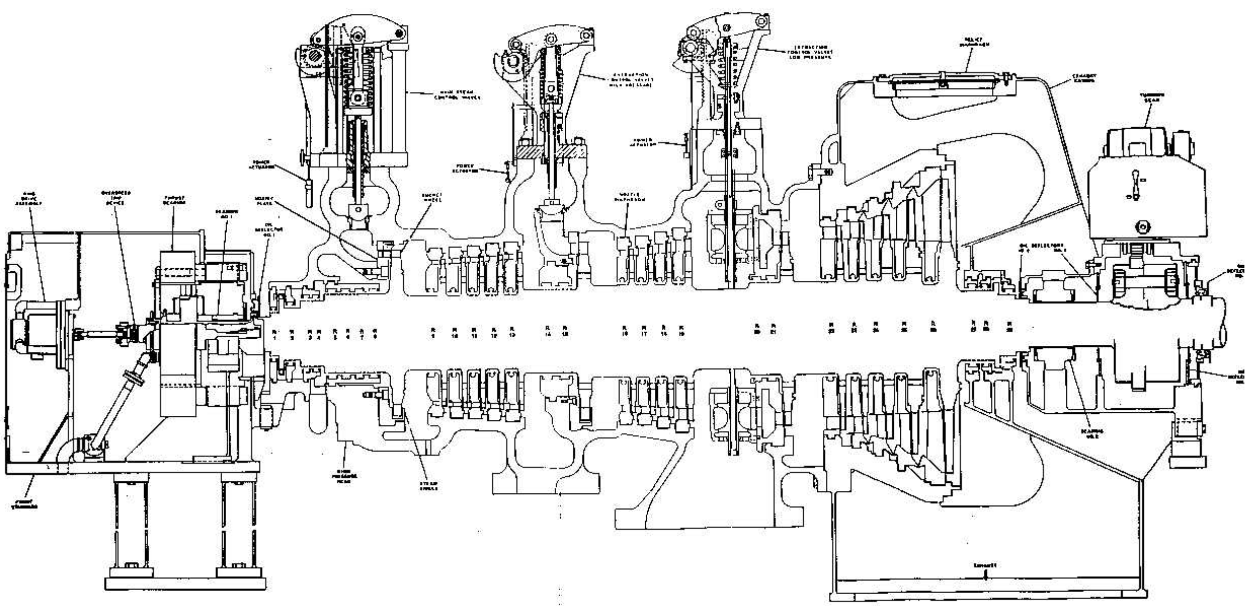
Figure 6 – Single and Multistage Steam Turbines (Courtesy Elliott Company)



2.B.7 Single Casing Admission/Extraction Multistage Steam Turbines

The typical construction of a 35 MW admission/extraction steam turbine is indicated in Figure 7. This turbine consists of 16 stages grouped into three different sections (HP, IP, and LP) with an admission valve at the inlet to the IP turbine section and extraction valve located at the inlet to the LP turbine. These size machines will utilize an integrally forged rotor (discs/shaft), journal and tilting pad thrust bearings, labyrinth type seals, and non-return valves downstream of the extraction valve. This condensing, non-reheat design has several features common to many steam turbines rated at less than 120 MW and with those that provide extraction steam capabilities. These types of steam turbines are utilized in paper mills and steel mills to drive generators or turboblowers as well as to reduce the pressure of boiler supplied steam for other plant services. In the oil and gas industry, these types of turbines are also utilized to drive compressors.

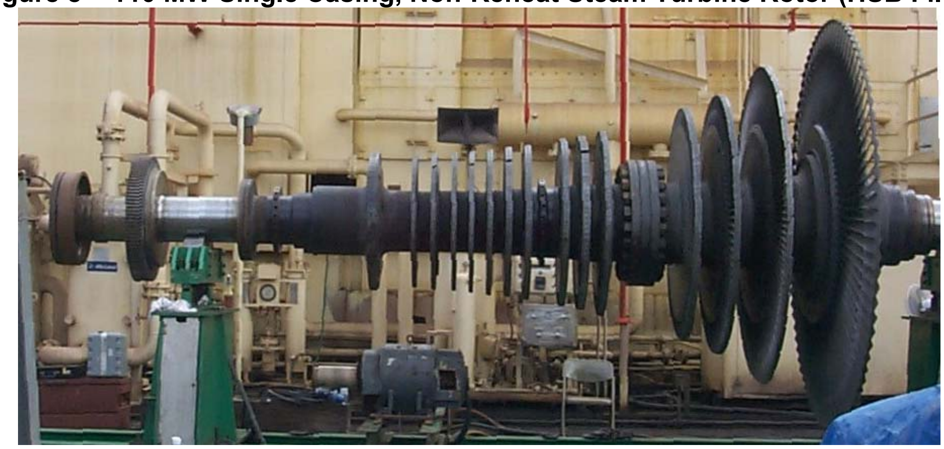
Figure 7 – Single Casing Admission/Extraction Steam Turbine (Courtesy General Electric)



2.B.8 Single Casing Non-Reheat Multiple Stage Steam Turbines

A 15 stage 110 MW single casing, non-reheat steam turbine rotor is shown in Figure 8. This turbine is similar to the Figure 8 single casing turbine with separate HP, IP and LP flow sections; however, this turbine is physically much larger in size and used to produce power in cogeneration and older-generation combined cycle applications. It is noted that the generator is connected to the end of the LP section of the turbine.

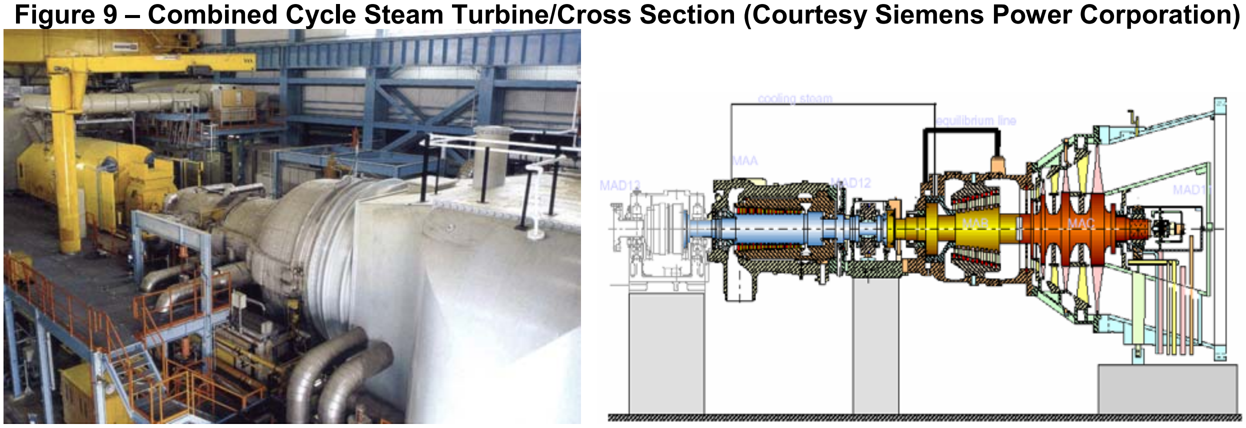
Figure 8 – 110 MW Single Casing, Non-Reheat Steam Turbine Rotor (HSB Files)



2.B.9 Single Casing Reheat Multiple Stage Combined Cycle Steam Turbines

With the rapid growth in combined cycle plants, the steam turbines utilized in these plants have changed substantially. A modern version is shown pictorially and in cross section in Figure 9. In particular, the generator is now connected to the steam turbine at the steam inlet side (HP) of the turbine rather than the turbine exit (LP); use of exhaust diffusers and axial condensers are utilized more frequently than vertical condensers; three steam inlets to the turbine are utilized, one from each steam drum (up to three for triple pressure HRSG's); and the steam stop, control, intercept valves have been combined into integral assemblies to save space and cost. Of course, these changes have not been without problems. Control of HRSG steam/water quality to the turbine is poor compared to fossil plants, and, consequently, there have been numerous incidents of turbine deposits and sticking of the integral valve assemblies. These incidents are in addition to more rub incidents because of the tighter radial and axial turbine clearances.

Figure 9 – Combined Cycle Steam Turbine/Cross Section (Courtesy Siemens Power Corporation)

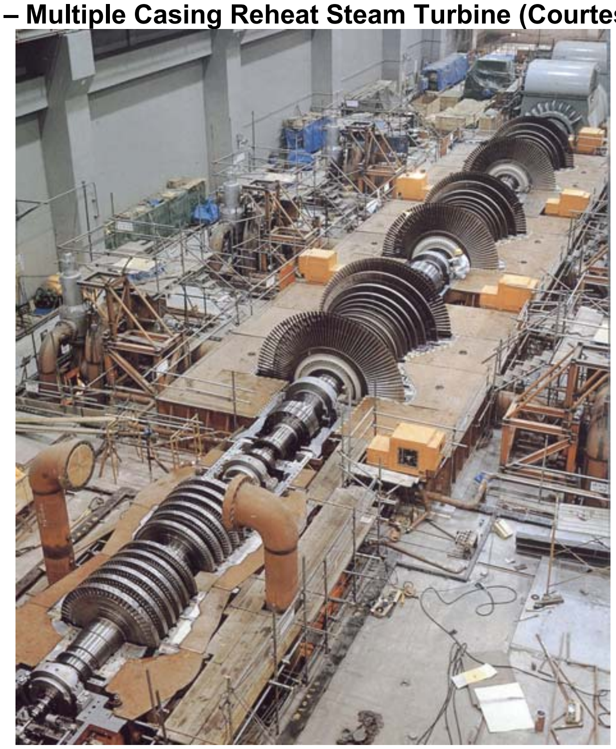


2.B.10 Multiple Casing Multiple Stage Reheat Steam Turbines

A modern five casing reheat steam turbine in shown in Figure 10. As previously discussed, the number of casings will be a tradeoff between cost, turbine efficiency, and last stage blade risk. As with the combined cycle steam turbines, there have been design changes made to stop, control, and intercept valves to integrate them together as combined assemblies. These are clearly shown to the right and left of the HP and IP turbines casings in Figure 10. In general, the number of casings do present an overhaul challenge as 5 separate turbines have to be aligned to each other and to the generator as shown in Figure 11. As such, it is not uncommon for sectional overhauls to be conducted, i.e., the HP and IP turbines may be conducted as one overhaul and the LP turbines and generator conducted as a separate overhaul.

Figure 10 – Multiple Casing Reheat Steam Turbine (Courtesy Siemens Power Corporation)

Figure 11 – Multiple Casing Reheat Steam Turbine (Courtesy Hitachi)



3. Monitoring, Operations, Maintenance, and Training Infrastructure

Regardless of the size, number of casings, steam conditions, and arrangements, it is essential that steam turbines have effective monitoring, operating and maintenance procedures/practices, and training for personnel. These topics are discussed in the next sections.

3.A Monitoring

3.A.1 Equipment Monitoring

To effectively manage the health and performance of steam turbines, there are a number of turbine parameters which should be measured, monitored and/or displayed on a continuous basis. How much information is monitored is a function of the steam turbine design and application, but with today's modern steam turbines, the following parameters should be monitored:

- Speed (RPM) and load (kW/MW, or shaft horsepower (SHP))
- Steam turbine inlet pressure and temperature
- Steam turbine 1st stage pressure and temperature (these are the conditions downstream of the first/large impulse stage before remaining HP section blading, as applicable)
- HP turbine outlet (or cold reheat), IP turbine inlet (or hot reheat), and IP turbine outlet/LP turbine inlet (or crossover) pressures and temperatures for reheat and multiple shell turbines only
- Steam turbine rotor/shell differential expansions (as applicable for large turbines)
- Steam turbine shell and steam chest temperatures/differentials (lower and upper half thermocouples installed in HP and IP turbine sections for large turbines)
- Admission and extraction pressures and temperatures (as applicable)
- Extraction line thermocouples to detect water induction (as applicable)
- Water and steam purity at the main steam inlet and condensate pump discharge
- Sealing steam and exhauster pressures (as applicable)
- Steam turbine exhaust pressure and temperature
- Lube oil and hydraulic fluid supply pressures and temperatures
- Cooling water supply pressures and temperatures for the lube oil and hydraulic fluid systems
- Journal bearing and thrust bearing metal temperatures (or drain temperatures, if applicable) for the turbine and gearbox (as applicable)
- Bearing vibration – seismic, shaft rider, or shaft x-and-y proximity probes measurements for all turbine and gearbox (pinion) bearing locations (as applicable)

Monitoring of these and other parameters is typically done in conjunction with today's modern turbine digital controls and plant control room systems. These systems will also handle the starting sequence, synchronizing, loading, speed governing, alarms, and trip logic for the turbine, gearbox (if present), generator, and any supporting systems. These systems also provide the electronic portion of the protection (i.e., turbine overspeed) for critical turbine and generator parameters. For older units there may be an analog control system which provides limited protection along with mechanical/electrical devices on the unit. There usually is a limited display of monitoring parameters. For even older units, all operation will be manual with only a gage panel to monitor a few turbine parameters. Vibration monitoring is done periodically using hand-held instrumentation. These older units are dependent solely on the knowledge of the operating staff, the presence and use of written operating procedures, and the mechanical/electrical devices on the unit for protection. All of these issues are important for every unit but the consequence is higher with older, outdated units.

Because the amount of equipment monitoring may depend on the complexity of the steam turbine, the ***minimum acceptable*** turbine parameters that should be monitored by turbine type/size are indicated in Table 2:

Table 2 - Recommended Steam Turbine Monitoring Parameters by Turbine Size/Type

Steam Turbine Parameters to be Monitored Continuously	Small Single Stage Units 0.5-2 MW	Medium Size Multi-stage Units 1.5-10 MW	Admission/ Extraction and Non-Reheat Units <100 MW	Combined Cycle Reheat Units	Large Reheat Subcritical and Super-critical Units
Speed (RPM)	X	X	X	X	X
Power (MW or SHP)	X	X	X	X	X
Steam Turbine Inlet Pressure	X	X	X	X	X
Steam Turbine Inlet Temperature	X	X	X	X	X
Steam Turbine 1st Stage Pressure		X	X	X	X
HP Turbine Outlet, IP Turbine Inlet, IP Turbine Outlet/LP Turbine Inlet Pressures and Temperatures				X	X
Admission Steam Inlet Pressure and Temperature (As applicable)			X	X	
Extraction Steam Outlet Pressure and Temperature (As applicable)			X		
Turbine Exhaust Steam Pressure	X	X	X	X	X
Turbine Exhaust Steam Temperature			X	X	X
Sealing Steam Pressures	X	X	X	X	X
Sealing Seal Exhauster Vacuum		X	X	X	X
HP and IP Turbine Shell/Steam Chest Temperatures/Differentials			X	X	X
Rotor/Shell Differential Expansions			X	X	X
Rotor Eccentricity			X	X	X
HP and IP Stress					X
Extraction Line and Drain Line Thermocouples			X	X	X
Lube Oil Supply Pressure	X	X	X	X	X
Lube Oil Supply Temperature		X	X	X	X
Lube Oil Sump Level			X	X	X
Bearing Metal or Drain Temperatures		X	X	X	X
Bearing Vibration (Seismic, Shaft Rider, or Proximity Measurements)		X	X	X	X
Thrust Bearing Wear/Temperatures		X	X	X	X
Hydraulic Fluid Pressures and Temperatures		X	X	X	X
Cooling Water Supply Pressures and Temperatures for Lube Oil and Hydraulic Fluid Heat Exchangers	X	X	X	X	X
Water and Steam Purity Monitoring		X	X	X	X
Control Valve Position (%) Indication		X	X	X	X
Admission and Extraction Valve Position (%) Indication			X	X	

3.A.2 Water and Steam Purity Monitoring

Contaminated steam is one of the prime causes of forced and extended maintenance outages and increases in maintenance costs. Contaminants can be introduced into steam from a variety of sources but can generally be categorized into two categories: 1) inert or deposit forming and 2) reactive or corrosion causing. The sources of contamination include the following:

- Water treatment chemicals for the boiler or condensate system
- Condenser leaks
- Demineralizer leaks
- Chemical cleaning of the boilers
- Process chemicals such as residues from black liquor in paper mills to polymers used in chemical plants
- Makeup water which may have rust, silica and other chemicals
- Corrosion products from condenser tubes and condensate piping

The principal cause of small to moderately large steam turbine contamination is mechanical carryover from the boiler system. These can result from:

- Over steaming
- High water levels
- High drum solids
- Separator problems
- Rapid load changes
- Chemical contamination

To systematically minimize these effects, design and implementation of water and steam chemistry controls that protect the boiler and turbine need to be established, superheater attemperation operation needs to be prudent, and steam purity monitoring needs to be implemented. The monitoring for the steam turbine, as a minimum, should include sodium and cation conductivity monitoring at the steam inlet to the turbine. In addition, it is advisable to monitor sodium and cation conductivity in the condensate and feedwater system downstream of the condensate pumps or demineralizer and at the deaerating (DA) tank outlet or economizer inlet to provide advance warning of water chemistry problems. Together, cation conductivity and sodium monitoring allow for the detection of the primary chemical causes (chlorides, sulfates, hydroxides) that are responsible for stress corrosion cracking of turbine steels. While other parameters (silica, hardness, etc.) in the water/steam may be monitored, their effect on turbine reliability is small compared to the primary chemical causes.

3.A.3 Water Induction Monitoring

Significant turbine damage can occur to a steam turbine when cool water or steam flows back into the turbine. When this happens during operation, steam turbine nozzle and/or bucket vibration increases and increases the potential for these components to break in the vicinity of where the cool water or steam is being introduced. Similarly, if the cool water or steam backflow occurs during starting, it can thermally distort the steam turbine rotor during the start and may cause major seal rubs and severely damaged blades. If the water or steam induction occurs during a shutdown after the circuit breaker has been opened, the turbine can and does overspeed to destruction.

The American Society of Mechanical Engineers (ASME) developed recommended practices for the prevention of water damage to steam turbines in their procedures ASME TDP-1-1998.

Unfortunately, most of the current steam turbines were designed and installed before the initial version of the standard was issued in 1985. Regardless, the standard provides excellent recommendations to minimize water induction. For the small to moderately large steam turbines, the following is suggested as the minimum basic requirements to detect and reduce the probability of water or cool steam induction:

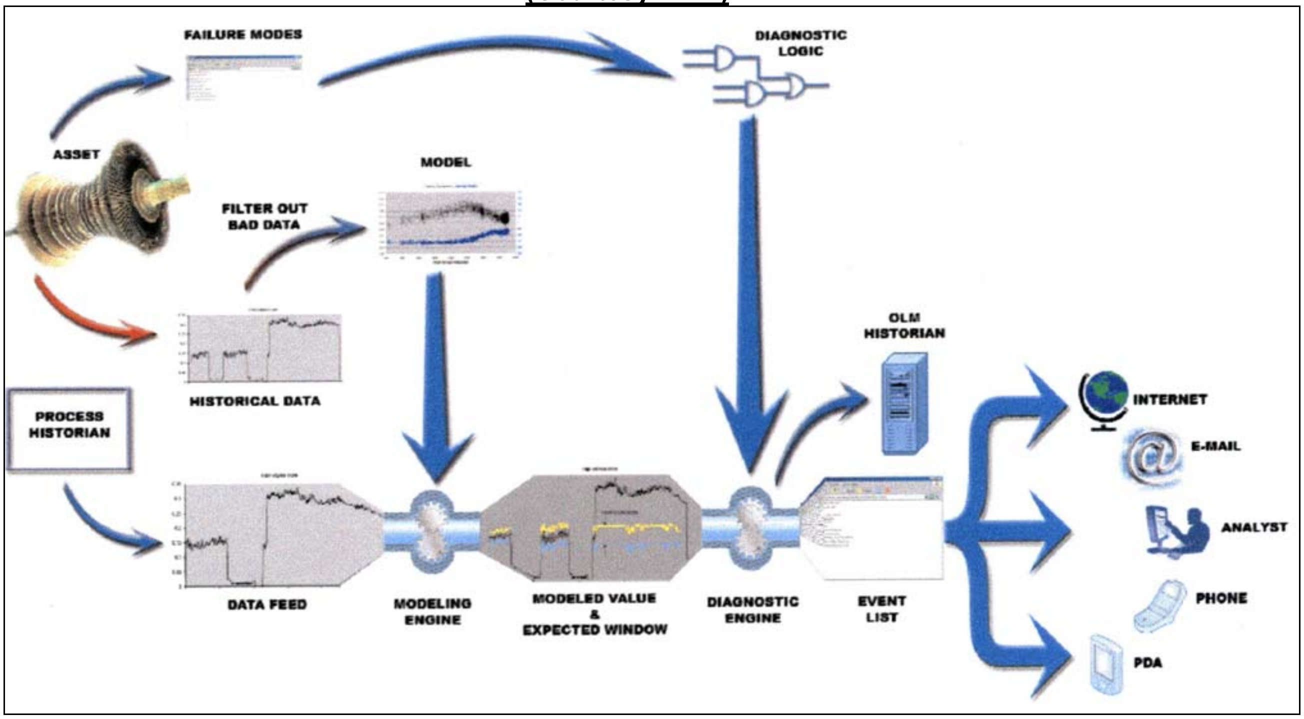
- Test extraction non-return valves (NRV) daily to ensure proper operation
- Install and monitor thermocouples on the controlled and uncontrolled extraction lines to detect drops in temperature that may be indicative of a potential water induction incident
- Ensure sealing steam drains and casing drains are free, that valves installed downstream of drains are in the proper position, that drains are not manifolded together to restrict flow, and that the drain lines actually drain downward
- Ensure that feedwater heater (if present) levels are kept at required levels and that level detector alarms are added to alert the operator of a problem
- Ensure steam header low point drains, main steam stop and T&T valve drains, control/extraction valve drains have valves in the proper position for draining and that the drain lines do drain downward, not upward
- Ensure attemperation spray control valves close on boiler fuel and turbine trips and that there is a block or shutoff valve in series with the spray control valve to ensure there is no leakage into the turbine
- Monitor the difference in thermocouple readings (if present) on the upper and lower halves of the turbine shell. A large difference between halves and/or a cooler lower half could be indicative of water induction

3.A.4 Condition Monitoring

While continuous monitoring of steam turbine parameters is important, use of that information to detect changes in equipment health and condition in advance of possible failures is equally important. As such, the steam turbine parameter data can be used for historical recording, for trending of turbine readings, for calculating turbine performance, and for detecting changes in vibration signatures (level, phase angle, frequency changes, orbit changes, etc.) with time. Consequently, if the data is collected and analyzed properly, changes in state or leakages between or within components can be detected and utilized for assessing turbine life issues. These analyses may be done off-line or may be accomplished on-line with intended goal of detecting changes in health before failure so that corrective actions can be taken in timely and cost effective manners.

The U.S. Electric Power Research Institute’s (EPRI) vision of an effective enterprise on-line condition monitoring system is shown in Figure 12. Besides collecting and storing steam turbine parameter data, it also includes constructing diagnostic/failure models of the turbine sections and subsystems which use the data to predict what may be in process of failing. While such an approach may be the ultimate in equipment monitoring, all of the capabilities are not necessarily needed at a plant. What is needed, however, is the ability to detect changes in turbine performance by turbine section, the ability to detect changes in the turbine’s vibration signature (levels, phase angle, frequencies), and the ability to detect changes in expected versus actual values for critical turbine components with time. Whether these analyses are done by hand, by computer, on-line or off-line, is of no consequence. What does matter is that the plant is actively determining with time whether its turbine is operating normally and whether there are differences in expected readings which require timely corrective or investigative action.

Figure 12 – Electric Power Research Institute Vision of On-Line Steam Turbine Monitoring (Courtesy EPRI)



3.B Operations, Maintenance, and Training Infrastructure

3.B.1 Operations

While having instrumentation to display/monitor steam turbine parameters and having the capability to conduct diagnostic analyses of those parameters are essential, it is equally important that validated operating procedures be developed and documented for the operations staff of a plant. Consequently, there are procedures and documentation that should be prepared, available in the control room, and followed by operating personnel to ensure the unit is operated properly within the limits established by the turbine manufacturer. The items below are the typical type of procedures required, regardless of the complexity of the steam turbine.

- Technical manuals and service bulletins available, complete and current
- Equipment logbooks (records starts, trips, unscheduled and scheduled events/maintenance) maintained and current
- Pre-start checklist for auxiliaries (lubrication, hydraulic, cooling water, sealing steam, etc.)
- Pre-start checklist for turbine
- Starting/warm-up/slow roll procedures
- Loading procedure
- Operating procedures (changing loads/responding to changes in turbine conditions and alarms)
- Unloading and shutdown procedures
- Emergency shutdown procedure
- Steam purity corrective action procedures
- Overspeed test procedures for steam turbine and steam driven boiler feed pumps
- Control valve, main stop, and trip and throttle valve test procedures
- Loss of lubrication test procedures including pressure switches, pump start logic, etc.

Experience has shown that the operating procedures are most effective when they are prepared by the plant based on input from operations and maintenance personnel as well as the original OEM documentation. To ensure that unauthorized or technically incorrect changes are not made to operating procedures, it is important that a “Management of Change” procedure be put in place and followed for making controlled changes to all procedures.

3.B.2 Maintenance Management

Achieving high steam turbine reliability and availability levels requires conducting the proper maintenance and inspections in a timely manner. The workscope and periodicity of expected maintenance tasks is discussed in Section 5; however, this section is concerned with the infrastructure for managing maintenance successfully. As with managing operating procedures and documentation, some form of maintenance management is required for the turbine and all its supporting systems. Whether it is a computer-based maintenance management (CMM) system or machinery record cards is not important. What is important is that there is a system in place to schedule and track completion of maintenance tasks and that there is some feedback from the maintenance to adjust the periodicity and scope of tasks. In addition, because much work is outsourced today and few spares are maintained at plants, it becomes necessary to ensure that there are procedures for controlling contractor work. There is also a need to establish preplanning procedures for unscheduled outages when mobilization of resources and parts needs to be accomplished on a crisis schedule. As a minimum, maintenance documentation and practices for steam turbines should include the following:

- Technical manuals and service bulletins available, complete and current
- Maintenance management system in place and followed (computerized or manual system)
- Lock-out/tag-out procedures available and followed
- Contractor control procedures available and followed
- Emergency preplanning procedures for major unscheduled events available and current
- “Management of Change” procedure in place and followed for making controlled changes to all maintenance procedures and practices.

There are a number of industry approaches and sophisticated software for establishing maintenance programs for steam turbines and their supporting equipment. These approaches include running to failure, preventive maintenance (PM), reliability centered maintenance (RCM), and other variations that utilize failure causes and the value of the hardware in establishing maintenance priorities. ***Regardless of the system or approach, what is important to insurers is that the maintenance tasks and frequencies should be prioritized towards the portions of the steam turbine that have the highest risk - the highest probability and consequence of failure. This usually means protecting the steam turbine from overspeeds, water induction, loss of lube oil, corrosive steam, and sticking valves that could cause major damage to the turbine in either the short or long term.*** While other maintenance may be important, insurance priorities should be on the failure mechanisms and events that could result in major steam turbine damage.

3.B.3 Training

In spite of the increased level of sophistication with turbine controls and condition monitoring, the last level of failure prevention or mitigation are the operations and maintenance staffs. It is becoming increasingly important that staffs be continually trained as the loss or graying of knowledgeable personnel is resulting in a brain drain in many industries. It is important that personnel be trained in the why as well as what needs to be done to operate/maintain complex equipment.

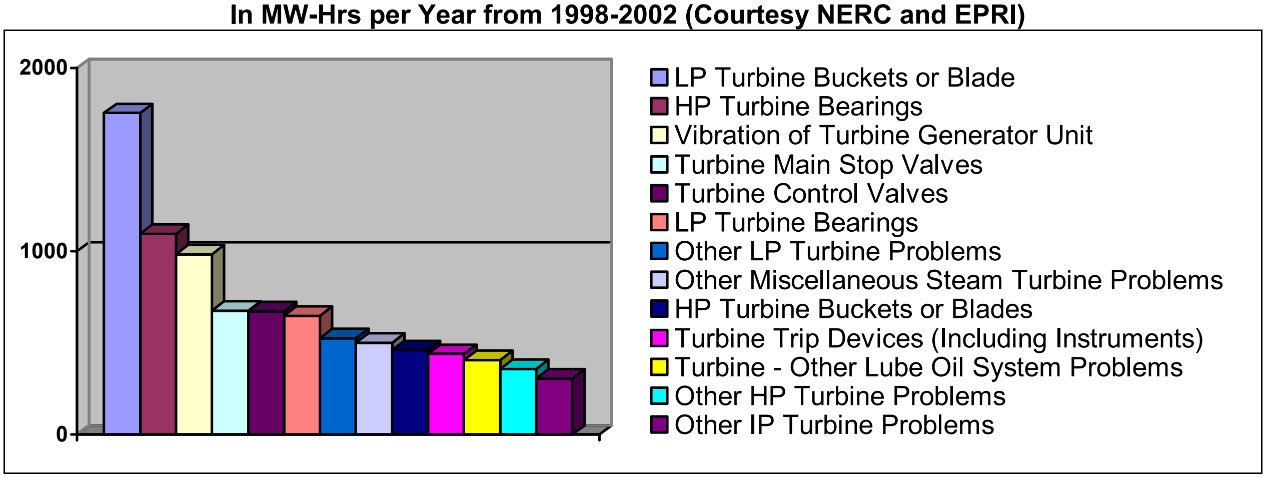
As such, each plant should have a training program in place with records indicating when and what training has been conducted for each individual. Similarly, the use of plant simulators is encouraged to allow operators to be trained or retrained when changes to the plant have been made besides keeping their personnel skills at high levels.

4. Steam Turbine Availability and Failure Experience

Before defining a comprehensive maintenance plan (tasks and frequencies) for steam turbines which addresses the inherent failure mechanisms and causes of failures previously discussed, it is important to review what steam turbine availability and failure experience has been today.

The leading causes of non-availability for U.S. industry fossil plant steam turbines, according to the North American Electric Reliability Council (NERC) and EPRI, are indicated in Figure 13. The largest categories for non-availability included LP turbine blades, turbine bearings (HP and LP turbine), turbine generator vibration, main stop and control valves, HP blades, turbine trip devices and lube oil system problems. Most of these causes are consistent with the discussions in prior two sections and failure mechanisms and causes for these components.

Figure 13 – Ranking of Top 15 Failure Causes for Fossil Steam Turbine Lost Availability In MW-Hrs per Year from 1998-2002 (Courtesy NERC and EPRI)



This rough cut through the U.S. power generation industry is also reflected in a composite of known failure cause analyses observed across several industries and countries. These are indicated in Table 3 along with a ranking of the relative frequency and severity of the failures (1=highest, 4=lowest). There are several notable items about the data:

- The highest frequency of failure has been loss of lube oil incidents. These have occurred in sizes ranging from 10 MW to 400 MW for the variety of the reasons indicated in the table. Unfortunately, many of the failures have resulted in turbine and generator rubs in addition to damage to the applicable bearings, which is the reason for the higher severity ranking.
- Not surprisingly, the highest severity failures have been overspeed events. These have been more predominant in smaller size turbines (<40 MW) for the causes indicated. While some of the failure causes are due to component failures, the others are due to improper checkout during commissioning or losing control (i.e., not having or following a procedure) during testing of a steam turbine with an uncoupled boiler feed pump.
- The bulk of the failures in terms of higher frequency and higher severity are blade/bucket failures. Most of the blade failures have been in the LP section of the turbine where the blades have experienced stress corrosion cracking or excessive erosion and FOD.

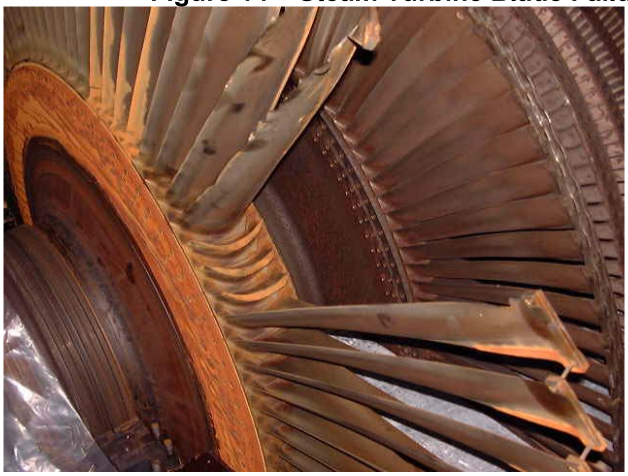
- Many of the remaining failures are driven by long term operation where the applicable failure mechanisms (erosion, corrosion, FOD/DOD) eventually wear the part to failure. These are generally not as high in frequency and severity as the previous types of failures.
- There continue to be resonance issues/failures with steam turbine blading. While many of the problems with older turbine designs have been resolved or managed, some of the new turbine designs for either small or large units have had cracks/failures particularly with the last stage blades.

Table 3 – Composite Industry Steam Turbine Failures - Mechanisms and Causes (HSB Files) (1=Highest, 4=Lowest)

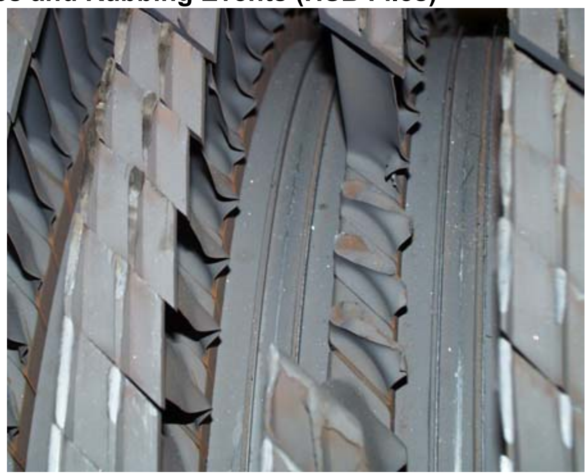
Component	Failure Mechanism	Cause(s)	Frequency Rank	Severity Rank
Turbine Rotor and Bearings	Loss of lube oil	1. Pressure switches did not work. 2. Backup lube oil pump did not work. 3. Duplex filter switching problem 4. Oil supply valve leaked 5. Ruptured bearing oil line	1	3
Bucket or Bucket Cover Failure	Fatigue, corrosion, erosion, rubbing, and SCC	1. Blade and/or cover cracked, pitted, thinned or eroded and finally broke. 2. Corrosive chemicals in the steam 3. High backpressure for last turbine stage. 4. Water induction 5. Resonance sensitive bucket design 6. Bowed rotor and/or humped shell	2	2
Turbine Rotor	Overspeed (OS) with or without Water induction	1. NRV stuck open during shutdown. 2. Mechanical OS device did not work. 3. Main Steam Stop/T&T valve stuck partly open. 4. Lost control of test 5. Controls – OS did not work	3	1
Turbine Rotor	Major rubbing, high vibration	1. Quick closing valve did not close properly (broken disk) 2. Direct contact of rotor with buckets, nozzles, seals, and shells 3. Misalignment 4. Protective system did not work	2	2
Nozzle and Buckets, HP and IP Stages	Solid particle erosion	1. Exfoliation – boiler inlet piping. 2. Main Steam Stop/T&T valve inlet strainer broke.	3	4
Nozzle and Buckets, LP Stages	Droplet erosion	1. Saturated steam in the LP turbine. 2. Poor turbine design.	3	4
Nozzles and Buckets, All Stages	Foreign or Domestic Object Damage (FOD/DOD)	1. Debris in inlet line to turbine. 2. Main Steam Stop/T&T valve inlet strainer broke. 3. Parts adrift inside turbine, or broken nozzle partitions or bucket shrouds.	4	3

To put the failures in perspective, Figure 14 shows examples of fatigue, water induction, SCC and rub-caused failures for turbines ranging in size from 90 MW to 350 MW.

Figure 14 – Steam Turbine Blade Failures and Rubbing Events (HSB Files)



Fatigue Failure Compounded by Condenser Extraction Line Backflow



Water Induction Rub Compounded by Attempts to Turn Thermally Locked Rotor

SCC Failure in LP Blade Leading Edge (Flame Hardended Area)

Rotor/Seals Welded to Inner Shell from Rub

5. Scheduled Maintenance and Overhaul Practices

5.A U.S. Maintenance Practices

There are no regulatory maintenance practices or intervals specified for non-nuclear steam turbines regardless of the industry or application. As such, the frequencies and tasks are defined by the turbine manufacturers, consultants, industry organizations such as EPRI, plant personnel, plant process requirements, or insurers based on past experience. Tables 4 and 5 indicate what is considered to be the **minimum recommended practice** for achieving high levels of reliability and availability, based on the discussions in Sections 2-4 and based on attempting to mitigate the risk of high probability and high consequence type failures.

Table 4 – U.S. Annual Steam Turbine Maintenance Frequencies and Tasks

Frequency	Maintenance Task
Daily or Less	1. Conduct visual inspection of the unit for leaks (oil and steam), unusual noise/vibration, plugged filters or abnormal operation
	2. Cycle non-return valves
Weekly or Less	1. Trend unit performance and health. Hand-held vibration readings should be taken from the steam turbine and gearbox if permanent vibration monitoring system is not installed
	2. Test emergency backup and auxiliary lube oil pumps for proper operation
	3. Test the main lube oil tank and oil low pressure alarms
	4. Test the simulated overspeed trip if present
	5. Cycle the main steam stop or throttle valve
	6. Cycle control valves if steam loads are unchanging
	7. Cycle extraction/admission valves if steam loads are unchanging.
Monthly or Less	1. Sample and analyze lube oil and hydraulic fluid for water, particulates, and contaminants
	2. Deferred weekly tests or valve cycling that experience has indicated sufficient reliability to defer them to a one month interval.
Annually	1. Conduct visual inspection and functional testing of all stop, throttle, control, extraction and non-return valves including cams, rollers, bearings, rack and pinions, servomotors, and any other pertinent valves or devices for wear, damage, and/or leakage.
	2. Conduct visual Inspection of seals, bearings, seal and lubrication systems (oil and hydraulic), and drain system piping and components for wear, leaks, vibration damage, plugged filters, and any other kinds of thermal or mechanical distress.
	3. Conduct visual, mechanical, and electrical inspection of all instrumentation, protection, and control systems. Includes checking alarms, trips, filters, and backup lubrication and water cooling systems
	4. Test the mechanical overspeed for proper operation annually unless the primary system is electronic and has an OS test switch. For that system, electronic overspeed simulations should be conducted weekly while mechanical and electrical overspeed tests should be conducted every 3 years. For electronic systems without an OS test switch, an overspeed test should be conducted annually.
	5. Conduct visual inspection of gearbox (if installed) teeth for unusual wear or damage, and gearbox seals and bearings for damage.
	6. Internally inspect non-return valve actuators for wear

Table 5 – U.S. Multiple-Year Steam Turbine Maintenance Frequencies and Tasks

Frequency	Maintenance Task
Minor Outages Every 2-4 Years	1. Conduct visual inspection or borescope of turbine nozzle block/inlet stages (HP and IP) and exhaust stages for FOD, corrosion, mechanical damage, and other damage. The inspections may be conducted more or less frequently, based on the condition of the parts.
	2. Internally inspect main stop/T&T, control, admission, extraction, and NRV valve internals for wear, seat leakage, and damage. For large machines, it may be advantageous to do valves on the right side of the turbine during one minor outage and the left side during a subsequent minor outage.
	3. Open, inspect, and check alignment of gearboxes with turbine/generator
	4. Calibrate all alarms, trips and protective system sensors/instrumentation
	5. Inspect foundations, slides, and anchoring hardware for wear.
Major Overhaul Outages Every 3-9 Years	1. Conduct major overhauls of line shaft turbines and gearboxes every 3 years
	2. Conduct major overhauls of steam turbines installed in reliability-critical and process-critical applications every 5-6 years
	3. Conduct major overhauls of steam turbines in general service with no specific service or risk factors every 5-8 years
	4. Conduct major overhauls of combined cycle steam turbines every 6-9 years in conjunction with combustion turbine hot gas inspections or complete overhauls, providing there are no risk factors or design issues with the specific model turbine.
Major Overhaul Outages Every 9-12 Years	Conduct major overhauls for large fossil steam turbines every 9-12 years on a case-by-case basis based on the following factors of influence: 1. Past history of problems 2. Generic problems based on industry experience with specific or similar models 3. Operational incidents since the last major overhaul 4. Conditions found and extent of NDE and repairs conducted (or not conducted) at the last major overhaul 5. Unit performance and condition monitoring capability (Section 3.A.1/4) 6. Water and steam purity monitoring capability (Section 3.A.2) 7. Turbine water induction protection provided (Section 3.A.3) 8. Quality of operations and maintenance practices, procedures, and personnel (Section 3.B) 9. Inspections and testing conducted between major dismantles (Table 4 and Table 5 annual and minor outage maintenance tasks) 10. Service duty starts/hours per year, load duty (baseload, cycling, swing, etc.) 11. Age and remaining/end of life issues There are different approaches, methodologies, and/or criteria utilizing the factors of influence above to determine acceptable major overhaul intervals when large size turbines are involved and large overhaul intervals are desired. The various approaches are discussed in detail in Section 6.
Special Outages	Conduct special inspection outages or workscopes in conjunction with major overhauls to assess the remaining life of rotors/shells with very high operating hours, rotors manufactured with older materials/processes, and rotors/shells subjected to extended periods of operation with high steam temperatures and pressures. The purpose of the life assessments are to determine the suitability of continued operation and remaining life of units subjected to long term creep, fatigue, or stress corrosion damage.

5.B European Maintenance Practices

Utilities and other operators normally adhere to their equipment manufacturer's recommendations and complement them with their own know-how and operational experience and with VGB or local recommendations (the latter ones usually are either based on VGB or are very similar to VGB). As such, most of the items in Chapter 5.A, Table 4, for the U.S. are equally valid for Europe. There might be some slight differences in the extent and possibly in the frequencies of the annual maintenance programs, but these are mainly due to the different approaches which the different operators take (and the money they have available) when it comes to maintenance.

There are no regulatory maintenance practices or intervals specified for non-nuclear steam turbines regardless of the industry or application. As such, the frequencies and tasks are defined by the turbine manufacturers, consultants, industry organizations such as VGB, plant personnel, plant process requirements, or insurers based on past experience. Tables 6 and 8 indicate what is considered to be the **minimum recommended practice** for achieving high levels of reliability and availability, based on the discussions in Sections 2-4 and based on attempting to mitigate the risk of high probability and high consequence type failures.

Table 6 – European Annual Steam Turbine Maintenance Frequencies and Tasks

Frequency	Maintenance Task
Daily or Less	1. Conduct visual inspection of the unit for leaks (oil and steam), unusual noise/vibration, plugged filters or abnormal operation
	2. Cycle non-return valves
Weekly or Less	1. Trend unit performance and health. Hand-held vibration readings should be taken from the steam turbine and gearbox if permanent vibration monitoring system is not installed
	2. Test emergency backup and auxiliary lube oil pumps for proper operation
	3. Test the main lube oil tank and oil low pressure alarms
	4. Test the simulated overspeed trip if present
	5. Cycle the main steam stop or throttle valve
	6. Cycle control valves if steam loads are unchanging
	7. Cycle extraction/admission valves if steam loads are unchanging.
Monthly or Less	1. Sample and analyze lube oil and hydraulic fluid for water, particulates, and contaminants
	2. Deferred weekly tests or valve cycling that experience has indicated sufficient reliability to defer them to a one month interval.
Annually	1. Conduct visual inspection and functional testing of all stop, throttle, control, extraction and non-return valves including cams, rollers, bearings, rack and pinions, servomotors, and any other pertinent valves or devices for wear, damage, and/or leakage.
	2. Conduct visual Inspection of seals, bearings, seal and lubrication systems (oil and hydraulic), and drain system piping and components for wear, leaks, vibration damage, plugged filters, and any other kinds of thermal or mechanical distress.
	3. Conduct visual, mechanical, and electrical inspection of all instrumentation, protection, and control systems. Includes checking alarms, trips, filters, and backup lubrication and water cooling systems
	4. Test the mechanical overspeed for proper operation annually unless the primary system is electronic and has an OS test switch. For that system, electronic overspeed simulations should be conducted weekly while mechanical and electrical overspeed tests should be conducted every 3 years. For electronic systems without an OS test switch, an overspeed test should be conducted

	annually.
	5. Conduct visual inspection of gearbox (if installed) teeth for unusual wear or damage, and gearbox seals and bearings for damage.
	6. Internally inspect non-return valve actuators for wear

Past OEM recommendations for one manufacturer for their medium-sized and large steam turbine sets are shown below in Table 7. The table and subsequent paragraphs indicate the typical pattern for the sequence and timing of turbine overhauls as well as the overhaul workscope. Some industry experience indicated that operators do inspections/overhauls a little more frequently than recommended by VGB in Table 8.

Table 7 – Typical European Manfacturer's Multiple-Year Steam Turbine Maintenance Frequencies and Tasks

EOH	Years After Commissioning	Type of Overhaul
10,000	Maximum of 4	Minor
25,000	Maximum of 8	Minor
50,000	Maximum of 15	Major
75,000	Maximum of 20	Minor
100,000	Maximum of 25	Major

A minor overhaul's duration would typically be about 2-4 weeks and would comprise the following workscope:

- Opening of turbine casings, only if necessary
- Visual inspection of the LP last stage blades
- Endoscopic examination of accessible parts of the turbine and the generator
- Inspection of the bearings
- Check of coupling concentricity
- Check and recalibration of the safety devices for turbine and generator
- Check and readjustment/ recalibration of the turbine control system
- Check of lube and control oil pumps and systems
- Inspection of the steam valves
- Examination of the condensing and feed-heating systems
- Visual inspection of the stator end windings, their bus bars and terminals, if this is possible without extensive disassembly work. The generator rotor is not dismantled
- Checking of excitation equipment (exciter, brush gear and slip ring brushes)
- Additional checks according to the particularities of the unit and individual operational observations

A major overhaul's duration would typically be about 4-8 weeks and would comprise the following workscope:

- All checks and examinations made during a minor overhaul
- Opening of the turbine casing (or all casings if consisting of several cylinders)
- Examination of the blading
- Complete examination of the couplings, including axial run-out test
- Dismantling and examination of the generator rotor

- Inspections of the entire stator winding (end winding support, slot wedging, banding, bus bars, terminals)
- Examination of the entire stator core for strength and damage
- Disassembly and inspection of the excitation equipment (exciter, brush gear and slip ring brushes)
- Additional checks according to the particularities of the unit and individual operational observations

After reaching 100,000 EOH the OEM's typically recommend performance of an assessment of the remaining lifetime for some critical components as e.g. rotor, some highly stressed regions of the HP casing, HP inlet valves, etc. These recommendations correlate well with the VGB recommendations shown in Table 8 below.

Table 8 – VGB Multiple-Year Steam Turbine Maintenance Frequencies and Tasks

Frequency	Maintenance Task
Minor Overhaul Outages Every 25,000 EOH (Approximately Every 2-4 Years)	1. Check spacer bolts at bearing housings and casing brackets
	2. Examine shutoff valves of exhaust steam pipes and of automatic and non-automatic extractions on their actuator and steam sides
	3. Visually examine last stage of condensing turbine for erosion
	4. Examine earthing brushes for wear/function
	5. Examine control and protective equipment including automatic test facility, giving attention to parts subject to wear, tear and contamination
	6. Perform functional testing of supervisory equipment, overhaul and calibrate equipment as necessary
	7. Inspect filters and fluid pipes for damage
	8. Inspect fluid vapor extraction and conditioning systems
Intermediate Overhaul Outages Every 25,000 EOH (Approximately Every 2-4 Years)	1. Same tasks as Minor Overhauls
	2. Check couplings (bolts, torque, alignment, runout, clearances)
	3. Disassemble bearings - check clearances, wear, seal ring condition
	4. Check foundation slide condition
	5. Check anchor bolt preloads
	6. Check emergency stop, control, and bypass valves on the actuator and steam sides – replace wearing parts
	7. Remove and inspect steam strainers
	8. Inspect drain system pipes, fittings and traps
	9. Inspect condenser interior
	10.Check evacuation system
	11.Inspect spray water systems (HP, LP bypass, gland and exhaust steam desuperheaters)
Major Overhaul Outages Every 100,000 EOH	The VGB criteria are discussed in Section 6.
Special Outages	The VGB criteria are discussed in Section 6.

5.C Japanese Maintenance Practices

In Japan, with deregulation advancing in various industries, the Electricity Business Law (the Law) was amended in 1995 to allow Periodic Self Maintenance in addition to the Regulatory Periodic Maintenance (maintenance mandated by government authorities based on regulatory laws), and the Regulatory Periodic Maintenance interval was lengthened to twice the previously required period. This is due to the background of recent advances in technology increasing the reliability of the equipment and an increase in safety levels. Further, according to directives for the Law, thermal power plant owners have a duty to strictly manage their daily operations and to fully optimize their independent safety measures and attain the utmost standard of safety.

Periodic Self Maintenance must be commenced within 4 years from the most recent Regulatory periodic maintenance or the periodic self maintenance, and its records must be kept for 5 years. The records will be inspected during the subsequent Regulatory Periodic Maintenance.

In Table 9 the guidelines for the items for periodic self maintenance are indicated. These are nearly similar to the regulatory periodic maintenance. The detailed maintenance items and the schedules of power plants' adherence to the guidelines cannot be reported since these are not disclosed to the public.

Table 9 – Japanese Periodic Self-Maintenance Steam Turbine Maintenance Frequencies and Tasks

Frequency	Maintenance Task
Daily	1. Inspect for unusual noise and vibration
	2. Inspect for leaking of steam from unit
	3. Inspect for loose nuts and bolts
	4. Inspect vibration or abnormal noise of the bearings as well as excessive heat-up of lube oil
Every 4 Years	1. Inspection of shell interior by removing upper casing of HP and IP without removing separators and labyrinth packing
	2. Inspection of the following while rotating shaft - shaft, bucket, blades and base, shroud lacing wires
	3. Inspection of the upper half of HP and IP, and 1st row exhaust Inspection of separators without removing
	4. Visual inspection of bearings
	5. Overhaul of major valves and inspection of strainers, valve shell and valve base
	6. Inspection of the speed governor systems, emergency speed governor systems and trip mechanisms
Every 8 Years	Inspect shell interior by removing LP casing without removing separators and labyrinth packing
As Appropriate	Liquid penetrant testing (PT) inspection of above parts.

The standards for widening the intervals of periodic maintenance are laid out separately from the guidelines as follows:

a) For plant equipment with normal operating hours

Extension period- Up to one month

<u>Conditions for extension</u>

1. Daily operations are carried out according to the Directives of the Law
2. Operating hours exceeding 5% of the rated pressure is within 12 hours annually.
3. The plant has not been operated at more than 28°C (50°F) above the rated temperature, total hours operated at 8°C (14°F) above rated temperature is within 400 hours annually, and further the total hours operated above 14°C (25°F) is within 80 hours.
4. Daily inspections are carried out according to the Directives of the Law.
5. No abnormalities were detected at the previous inspection or that abnormalities or disorders were repaired and/ or prevention measures appropriately taken.

6. After the previous inspection, if an accident or disorder occurred, the damaged item was permanently repaired and measures taken to prevent any recurrences, and the same prevention measures taken to any similar items of the plant.

b) For plant equipment with low operating hours

For plants with low operating hours subsequent to the last Periodic Self Maintenance or Regulatory Periodic Maintenance, an application for a change in inspection interval can be submitted with a maximum of the following, whichever comes earlier:

1. Operating hours: 8,000 hours
2. Number of startups: 240 times (480 times for units that have completed prevention measures for low cycle fatigue)

However, the maximum inspection interval allowable at any one application is 4 years.

6. Approaches/Methodologies/Criteria for Establishing Longer Time Intervals between Major Overhauls

With the highly competitive nature of today's markets worldwide regardless of industry segment, companies cannot afford to do major steam turbine generator outages too frequently. The outages are expensive to execute while incurring additional expenses and/or lost revenue while the unit is off-line for the outage. Of course, waiting too long to perform an outage may result in more damage to repair, or worse, having to undertake a forced outage to repair disabling damage. However, over the past several years, it has been demonstrated that steam turbines and generators can successfully run longer than 5 to 6 years between outages that had traditionally been an industry standard in many parts of the world. This has been particularly true for units where the amount of internal wear/damage found during overhauls was neither significant nor reflected a high probability of a near term failure (i.e., few years).

So how does an owner, operator, or insurer of steam turbines decide what is the right interval to accomplish major outages and how do you ensure that the longer outage interval is reliably and safely achieved? There have been a number of approaches utilized in the past and there are different methodologies utilized in various industries today. The basic principle, benefits, and effectiveness of the approaches and methodologies are discussed in the next sections.

6.A Management Directed Interval

The simplest approach used by many companies was the management directed interval, i.e., there was no money to do major outages more frequently than the time interval specified by the financial management of the facility. Unfortunately, many of these decisions were unilaterally made without any technical input or real assessment of the risk of failure of the company's turbines. Clearly, turbines which did not have a prior/current history of problems and only had limited wear/damage during past outages were lower risk candidates for longer outage intervals. However, using the same interval for all turbines, regardless of their past/current experience, resulted in many forced outages for those that chose this approach.

The problem with the management directed interval was not in specifying the interval but rather ensuring that subsequent steam turbine overhaul workscopes took a longer time period view of what work needed to be done. Simply stated, turbine overhaul and repair efforts needed to address all areas of the turbine which were most likely to have major damage or fail in the longer specified interval. If that approach is utilized for executing overhauls, then meeting a directed interval can be reliably achieved if all required work is accomplished. If you have a fleet of turbines, however, it will take several years to bring the condition of all the turbines to a level that they are all capable of longer intervals.

6.B Process and Criticality Driven Intervals

In many industries the steam turbine is utilized as part of a larger manufacturing process. For example, steam turbines in the chemical, oil and gas industries may drive centrifugal and reciprocating compressors that are part of a complex series of chemical processes. In these applications, steam turbine overhaul intervals and the allotted time for the overhaul are driven by the requirements of the process. As such, the overhauled turbines need to achieve the specified process interval without forced outages as loss of the steam turbine will cause shutdown of the process and lost revenue as high as $1M per day. For these applications the time interval between major outages has been specified at 6 years and, fortunately, most facilities have major spares to minimize the lost time should a significant failure occur.

In the steel, paper, and pharmaceutical industries, many steam turbines are integrated into the steam or pressurized air portion of the manufacturing processes. These turbines may drive turboblowers from available plant steam or may reduce the pressure of available plant steam for internal manufacturing processes while concurrently making electricity. In these cases, the time interval for overhauls may remain in the 5-6 year time frame because of the critical nature of the product and to ensure that the turbines maintain a high level of reliability. This same philosophy applies to critical combined heat and power (CHP)/cogeneration applications where high reliability is more important than the cost savings possible from extending outage intervals.

6.C Turbine Manufacturer's Intervals

Depending on the size of the steam turbine and the manufacturer, overhaul intervals may be specified in years of operation, equivalent operating hours (EOH), or based on condition. Manufacturers of smaller steam turbines tend to specify intervals in the 3-5 year time frame while most power generation industry manufacturers utilize a unique formula for EOH which may take into account the number of running hours, cold starts, warm starts, hot starts, trips from above or below specified load levels, rate of loading/unloading, and overspeeds. Unfortunately, the formulas are different for each manufacturer and many plants do not actively collect the applicable data to calculate EOH. As such, intervals may be specified by the manufacturer based on a external condition assessment (i.e., performance, vibration, known problems, past history) which may be more biased toward more frequent overhauls. For example, General Electric advertises that their steam turbines are designed for 12 years between major outages but their official service guidelines specify 5 years between outages.

6.D Electric Power Research Institute (EPRI)

In the mid-to latter 1990's EPRI undertook an industry effort to develop a means of determining the time between major outage intervals. The initial work was based on using decision analysis methodology coupled with probability/consequence information specified by the user to project what the net present value (NPV) of the turbine will be with time under various overhaul schedules and failure scenarios. A turbine overhaul was then required in the year when the calculated NPV of the turbine turned negative. The calculation methodology was the essence of their Turbo-X program.

That approach has subsequently been abandoned in favor of a condition assessment approach. Essentially, EPRI specifies that overhauls should be conducted every 80,000 EOH according to an EOH formula they have developed. In a addition to the EOH level, a condition assessment is conducted that is essentially a color-coding (blue, yellow, red, or green) of the level of degradation (some, significant, severe, or good condition) of major steam turbine components and systems. Unfortunately, there are no defined standards for determining which level of coding should apply or what increments or decrements to the EOH level should be made. Consequently, the levels are established by whoever is doing the assessment.

6.E VGB Standards

The VGB "Recommendations for the Inspection and Overhaul of Steam Turbines (2nd Edition, 1995)" defines several criteria for establishing overhaul intervals. VGB indicates that the first overhaul may be conducted after 100,000 EOH based on an EOH formula that only uses the number of operating hours and total number of starts. If no major issues or problems are found during that overhaul, subsequent overhauls may be conducted at the 100,000 EOH interval until such time that remaining life assessments or other available operating experience from comparable turbines indicate the need for shorter intervals. The 100,000 EOH intervals are based on several criteria including:

- Type of turbine (condensing with high steam wetness, turbine sections with austenitic steel, geared turbines, etc.)
- Mode of operation (continuous duty, off-load operation, starting/loading mode, sliding/fix pressure operation, etc.)
- Observations during operation (vibration, steam and oil temperatures and pressures, leakages, alignments, changes in service fluids, etc.)
- Special measurements (internal efficiency, vibration analysis, heat rate, foundation distortion)
- Functional tests (protective and control equipment)
- Life assessment calculations
- Turbine life expenditure
- Inspection interval of other unit components (steam generator and generator)
- Manufacturer and insurer recommendations
- Exchange of information with other utilities (weaknesses and breakdowns)
- Influence of downtime

Between major overhauls, minor or intermediate overhauls may be scheduled every 25,000 EOH for various components or portions of the turbine as previously discussed in Section 5.

6.F Risk-Based Methodologies

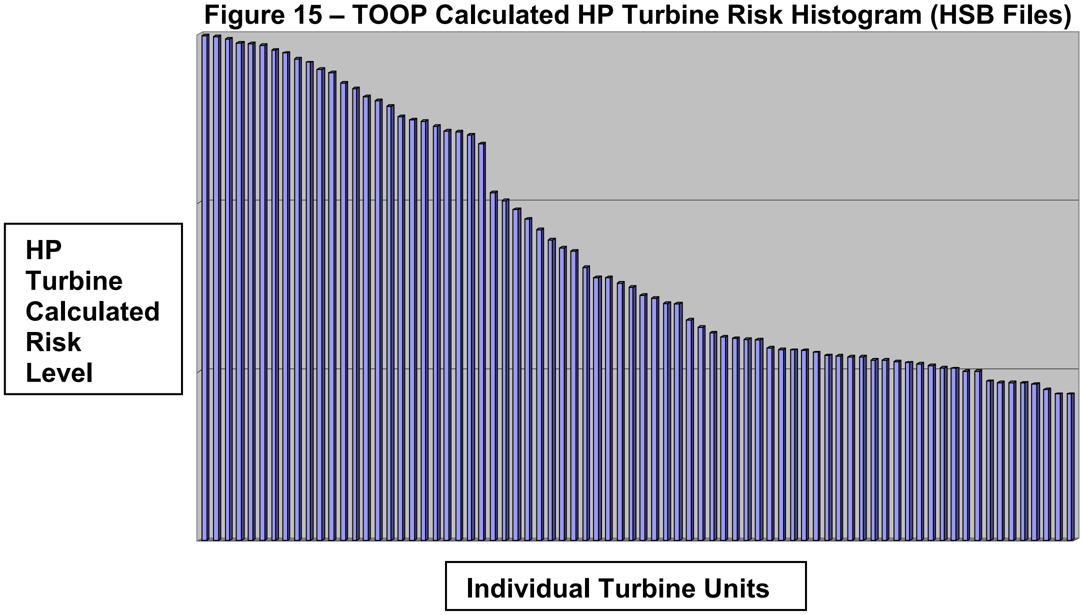
U.S. Experience

With the advent of deregulation in the U.S., it became apparent that utilizing the traditional 5-6 year interval for overhauls, whether the turbine needed it or not, was no longer compatible with the changes occurring in the industry. In addition, insurance inspections were subjective with risks assessments being based on the inspecting personnel's experience and judgment rather than objective criteria. Given the financial pressures being put on the industry, a more independent and uniform method of evaluation was considered necessary. As a result, Hartford Steam Boiler (HSB) initiated two risk-based analysis programs for steam turbines called STRAP (Steam Turbine Risk Assessment Program) for process steam turbines and TOOP (Turbine Outage Optimization Program) for power generation/utility steam turbines and generators.

These programs consist of algorithms that calculate risk (risk = probability of failure x consequence) for the steam turbine generator from the probabilities of failures, failure consequences, and engineering modifying factors included in the programs. The reliability and risk factors were developed by HSB with representatives from the power generation, manufacturing, process (refinery, petrochemical, chemical products), engineering consulting, and repair industries. The combined experience of the team members was leveraged to establish what attributes are important and necessary for a unit to achieve a longer time between major outages and corresponding lower risk levels. These attributes were converted into risk modifying factors to view turbine and generator risks on a holistic basis – design and construction, history, duty cycle, operation, maintenance, monitoring, and condition at past outages. The factors were calibrated with analyses of units of all kinds. The models and associated risk levels were then grounded with units that have run longer intervals to correlate risk level with time between major outage intervals measured in either EOH by the TOOP program or days of lost production by the STRAP program.

The risk models were developed based on ASME's Risk Based Inspection Guideline methodologies. Analyses have been completed for over 90 TOOP-size steam turbines, 130 STRAP-size steam turbines and 100 generators. These results reflect 11 turbine and 9 generator OEM's, size ranges from 590 SHP to 890 MW, operating hours from 12,000 to 340,000, or years of operation from new to 57 years. Times between major outages have ranged from 5 years to 12 years based on the associated risk level. As a side product of the calculations, individual turbines can be risk ranked with other company turbines or with manufacturer's units in the associated database. An example of the TOOP program calculated risk levels for HP turbines in the database is indicated in Figure 15. The HP turbine risk level is plotted on the Y-axis in descending order for the individual turbines listed on the X-axis. A correlation was established between risk levels and EOH between outages such that units with low calculated risks had longer times between outages than those with higher risk levels.

Figure 15 – TOOP Calculated HP Turbine Risk Histogram (HSB Files)



The methodology is quite effective in estimating outage intervals and defining risk-based maintenance actions which should be taken between major overhauls to achieve the longer interval. The process, however, does require a detailed review of plant documentation and practices, usually in excess of that accomplished during normal insurance inspections of steam turbines. ***Interestingly, the longer outage intervals have not resulted in any notable increase in the amount of damage, cost or time to complete major overhauls.***

<u>Japanese Experience</u>

Until the amendment of Japan's Electricity Business Law in 1995, electricity producers' individual maintenance procedures were not considered a valid form of maintenance. However, due to the recent deregulation of the electricity market, the producers' independent periodic maintenance has been recognized and machinery manufacturers and electricity producers have raced to adopt the risk based maintenance (RBM) approach and to cut total cost while maintaining the reliability of the plant equipment. The reason for this trend lies in the fact that 80% of the steam turbines in Japan are aged facilities with over 100,000 hours of operating time, and the parts have reached the period of accelerated wearing. Further, the emergence of independent power producers entering the electricity market is also one reason for the trend.

The RBM approach assesses and calculates the damageability and frequency of machinery failure thereby quantifying risk and further adds economic factors in constructing a maintenance plan for the plant machinery.

The RBM approach was initially developed by the American Society of Mechanical Engineers (ASME) Center for Research and Development with industry and insurer participation at the request of the Nuclear Regulatory Commission (NRC) as risk based guidelines for inspection. The complete set of guidelines was created in 1991 through 1994. In Japan the introduction of this approach began in the late 1990's for petroleum plants.

In order to apply this approach to the thermal power plants, data of plant machinery and past operations must be obtained from operators and manufacturers and analyzed utilizing probability theories, and this apparently has only been experimentally introduced these past few years. However, in order to sustain the reliability of the plant machinery and achieve cost reductions at the same time, this approach is indispensable, and a majority of operators are apparently conducting analyses and assessments and developing maintenance plans for their respective steam turbine generators. Regrettably, this information is not disclosed in Japan so there is no available information on the actual maintenance procedures and their analyses.

6.G Reliability Centered or Condition Based Maintenance (RCM or CBM)

In the past the frequency of overhauls was mostly based on the expected service lifetime of the most critical components. Overhauls were scheduled and done regardless of the actual condition of these components at the time. Based on the need of their customers for optimization of plant reliability and availability and at the same time cutting maintenance costs, all OEM's have developed plant data management systems which emphasize the collection of on-line operation and condition data, analysis of this data by expert systems and/or experienced engineers and giving feedback to customers utilizing these systems. All this is done in order to support and assist their customers with their daily operational problems and general maintenance scheduling as well as giving advice and support during outages and subsequent recommissioning of the plants.

Such systems can comprise plant monitoring and diagnostic modules and include transient data processing, early warning systems aimed at the detection of hidden and developing problems or failures, monitoring and diagnostic reports, plant assessment reports and other operational and maintenance related services which help operators in developing spot-on maintenance programs for their individual plants and avoiding unnecessary outages and unscheduled shutdowns. All this leads to condition oriented maintenance programs which allow service intervals to be extended if the units are operated in gentle operation modes and at the same time allowed to utilize the actual life time of the critical components before having to schedule overhauls if units are run in stringent modes.

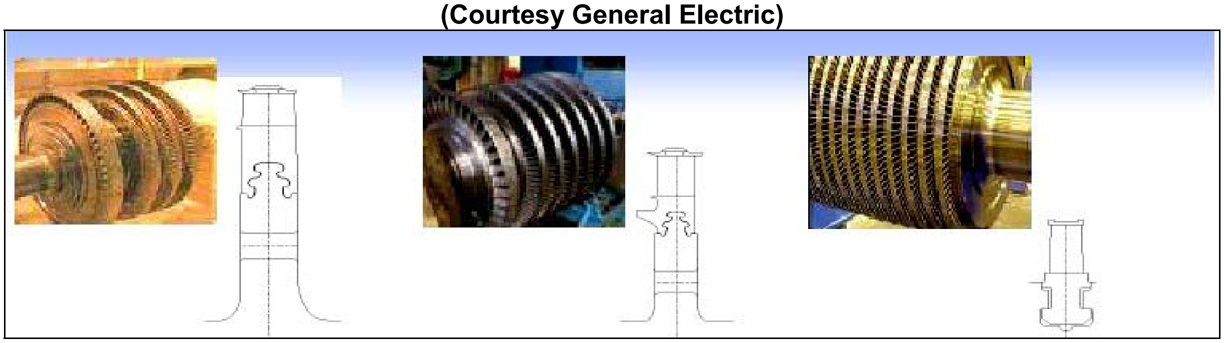
In summary, there are different approaches which may be taken for establishing longer time intervals between major overhaul outages. Regardless of the approach, methodology, or criteria utilized, what is important to insurers is that the maintenance tasks and frequencies between major overhauls are prioritized towards the portions of the steam turbine that have the highest risk. This means protecting the steam turbine from overspeeds, water induction, loss of lube oil, corrosive steam, sticking valves, and any other risk of failure or life issues that could cause major turbine damage and forced outages.

7. Issues with New Steam Turbine Technologies and Applications

Most of the previously discussed maintenance tasks and frequencies have been associated with steam turbine and technology levels that have been proven by many years or decades in service. Such is not the case with new steam turbine technologies. The advancements made in aerodynamics, seal design, and materials are changing the characteristics of new technology turbines.

In general, HP and IP turbines, for example, are moving towards using more reaction type blading than the original impulse type blading in these turbines. That is exemplified in Figure 16 moving chronologically from left to right. Most older generation steam turbines have primarily impulse blading. In the mid-to-late 1990's, some of these stages were replaced with more stages of reaction blading along with smaller radial and axial clearances. The technology level today is now moving towards even more reaction content resulting in a further increase in the number of stages and tighter axial and radial clearances. In some cases, the turbines are incorporating aero gas turbine technology levels to reduce seal leakage and improve efficiency. While it is difficult to object to technology improvements, the early experience of some of the new designs has been mixed. The new technology machines, not surprisingly, have been more susceptible to radial and axial rubs during starting and transients. Furthermore, they do not appear to be as tolerant of FOD debris in the incoming steam and tend to show increased wear and rubbing at blade tips.

Figure 16 – New Steam Turbine Trends Towards Reaction Blading and Smaller Clearances (Courtesy General Electric)

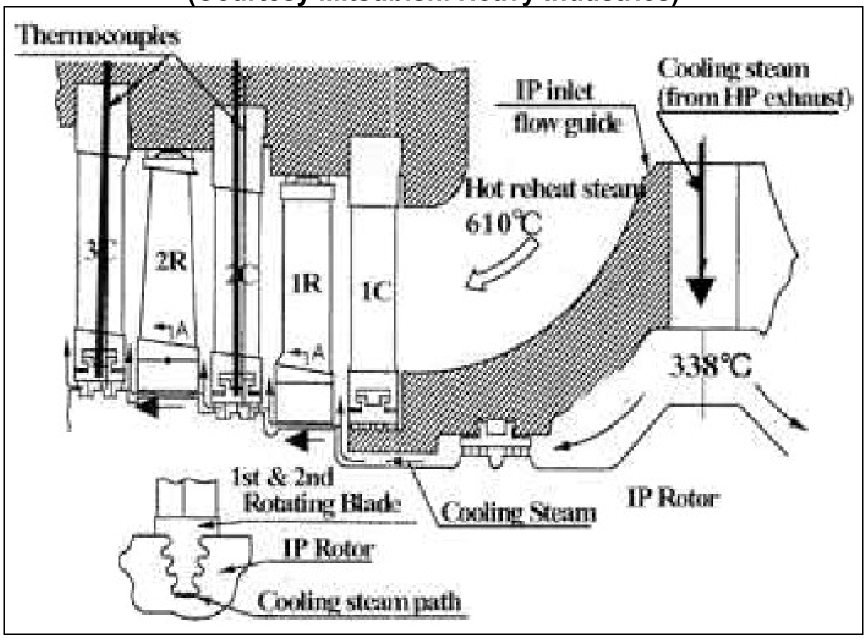


Impulse Stages Fewer Rows Wide Clearances	Increased Reaction Content/More Rows Reduced Clearances	Substantially Increased Reaction Content/Even More Rows Further Reduced Clearances

The situation with LP turbines is similar except that the general trend is towards using fewer stages but larger size blading to reduce the cost of new machines. Consequently, blading aerodynamic and attachment loadings (diaphragms and rotor discs) will be higher than that of prior generation of turbines, when compared on an equivalent basis. Use of titanium materials in some applications is an absolute necessity to achieve an adequate service life. In addition, there have been some natural resonance problems with LP last stage blading for some designs.

Additional turbine research and development is being directed towards high steam temperatures (700°C/1292°F) and pressures as well as utilizing steam for cooling shells and blading, all of which adds new concerns for equipment reliability. An example of steam cooling of the IP turbine utilizing HP turbine exhaust steam is shown in Figure 17.

Figure 17 – Example of Cooling IP Turbine Using HP Exhaust Steam (Courtesy Mitsubishi Heavy Industries)



In Japan there is a strong demand towards decreasing CO2 emissions, and increasing the efficiency of thermal power plants is an important issue. In particular, increased efficiency of steam turbines contributes greatly to the efficiency of thermal plants, and is therefore a crucial factor.

Approaches to increased efficiency of steam turbines can be largely categorized as (1) better steam conditions and efficiency of heat cycles (2) internal efficiency of the steam turbine itself. To meet these objectives, major Japanese turbine manufacturers such as Toshiba, Fuji Electric, Hitachi and Mitsubishi Heavy Industries (MHI) are developing technologies independently and have incorporated many of their achievements into their commercial turbines.

1. Better steam conditions and efficiency of heat cycles

   Steam conditions are moving towards higher temperatures and higher pressures. This requires changes in the turbine structure and improvement of turbine material. With these technological advances, in contrast to conventional steam conditions (241 bar/ 3,495 psi, 538°C/1,000°F), a 5 percent increase in efficiency can be expected for 600°C (1112°F) class turbines and an 8 percent increase can be expected for 650°C (1,212 °F) turbines. 600°C (1,112F) turbines are already in commercial use, and development for 650°C (1,212°F) class turbines are the main focus at present. New elements (W, Co, and B) have been added to 12 Cr steel as material for rotor blades to increase strength against creep.

2. Internal efficiency of the steam turbine itself

   The improvement of internal efficiency of steam turbines depends on how to minimize the various losses occurring within the turbine itself. These losses can be classified into several items and the newest prevention measures are incorporated at the design stage to improve each item. Many of them can be analyzed fairly easily due to the advances in aerodynamic numerical analysis. Examples are improvements in reaction blades, first stage blades and low pressure blades.

These new technologies and the design and material changes incorporated into a steam turbine have not been the cause of any heavy losses, but the inherent risk exposures are definitely increasing. At present, the radius of the rotor blades is getting larger, and the blade tip's revolving speed reaches high speeds of 680 meters per second (2,244 feet per second). Furthermore, the base of a 1219 mm (48 inch) rotor blade bears a centrifugal force of 590 tons. The designs of each company are all complex and unique, and the technological development and pursuit of increased efficiency will continue. New technological developments entail new risks to insurers. This is a reality which has not changed from the past.

In summary, there needs to be vigilance with regards to monitoring the reliability and availability of new technology steam turbines as they are not yet proven to be as robust as their predecessors. Therefore, scheduled maintenance and overhaul intervals should be conservatively defined until the new designs have sufficient, satisfactory operating experience.

8. Conclusions

From the previous discussions, several conclusions about the maintenance and overhaul of steam turbines can be made:

1. While there are substantial differences in the design, complexity, application, steam conditions, and size of steam turbines, they all are fundamentally the same. They perform the same function, utilize similar major components and supporting systems, and are subjected to the same failure mechanisms. Consequently, the expected maintenance and overhaul efforts for the major components to achieve high levels of reliability and availability would be expected to be similar, although the efforts do need to be tailored to the specific type of unit and application.
2. To support reliable turbine operation, there needs to be an effective infrastructure in place for monitoring the operating conditions, water/steam quality, and health of the steam turbine, for having and using written operating/maintenance procedures, for utilizing a maintenance management system to schedule/track maintenance, and for conducting training for personnel on an ongoing basis. The lack of an effective infrastructure can lead to lower levels of reliability and availability.
3. There have been numerous causes of steam turbine failures worldwide. Typically, the highest frequency events have been loss of lube oil incidents, the highest severity events have been overspeed events, and the higher frequency and higher severity events have been blade/bucket failures, particularly in the LP section of the turbine where they experienced a number of failure mechanisms (SCC, erosion, FOD) which ultimately led to failure. As such, steam turbine maintenance and overhaul efforts should be directed toward diagnosing and mitigating these types of events.
4. With regards to maintenance practices in North America and Europe, there are no regulatory maintenance practices or intervals specified for non-nuclear steam turbines regardless of the industry or application. As such, the frequencies and tasks are defined by the turbine manufacturers, consultants, industry organizations (EPRI, VGB), plant personnel, plant process requirements, or insurers based on past experience. In Japan, however, there are regulatory requirements for periodic maintenance. However, regardless of the area of the world, the recommended scheduled maintenance requirements for steam turbines are quite similar.
5. There are a number of different approaches which are utilized today for establishing longer time intervals between major overhaul outages. These include process/criticality driven intervals, turbine manufacturer's recommendations, industry group standards (EPRI, VGB), risk based methodologies, reliability centered and condition based methodologies. Regardless of the approach, it is important that the methodologies effectively establish the overhaul intervals based on the highest risk portions of the steam turbine.
6. The technologies being incorporated into new steam turbines are more sophisticated, require operation at higher pressures and temperatures, and generally have smaller clearances to improve efficiency. While the technologies have not caused any large losses, the inherent risk exposures are increasing and there needs to be continued vigilance with regards to monitoring the reliability and availability of these new units and to adjust their maintenance intervals accordingly.

In summary, what is important to insurers is that the maintenance tasks and frequencies should be prioritized towards the portions of the steam turbine that have the highest risk - the highest probability and consequence of failure. This usually means protecting the steam turbine from overspeeds, water induction, loss of lube oil, corrosive steam, and sticking valves that could cause major damage to the turbine, and conducting internal inspections of the turbine flowpath, shells and rotors for failure mechanism damage (creep, erosion, corrosion, fatigue, thermal fatigue, SCC) in order to detect the damage early enough to prevent a subsequent major failure.