

Turbine-Generator Auxiliary Systems, Volume 2: Turbine Steam Seal System Maintenance Guide

Technical Report

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Turbine-Generator Auxiliary Systems, Volume 2: Turbine Steam Seal System Maintenance Guide

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REPORT SUMMARY

The *Turbine-Generator Auxiliary Systems, Volume 2: Turbine Steam Seal System Maintenance Guide* provides nuclear and fossil plant personnel with operation and maintenance guidance on the turbine steam seal system components.

Background

Input from member utilities indicates that maintenance guides are needed for the turbine-generator auxiliary systems. The first auxiliary system selected was the turbine-generator lubrication system for nuclear and fossil power plants. *Turbine-Generator Auxiliary Systems, Volume 1: Turbine-Generator Lubrication System Maintenance Guide* (EPRI report 1010191) was published in December 2005. The second auxiliary system selected was the turbine steam seal system used in nuclear and fossil power plants.

Objectives

- To assist plant maintenance personnel in the identification and resolution of problems with equipment in the steam seal system
- To provide a comprehensive maintenance guide for the steam seal system equipment

Approach

A technical advisory group was formed that consisted of turbine-generator equipment owners from members of the EPRI Nuclear Steam Turbine Initiative and the Steam Turbines, Generators, and Balance-of-Plant Program. Input on current maintenance issues related to the steam seal system was solicited, and key suppliers of steam seal components were solicited for input and to review the report. In addition, a search of EPRI literature was conducted to include the latest technologies available.

Results

This report includes a description of a typical turbine steam seal system, including various pieces of equipment and their functions. Preventive/predictive maintenance and condition monitoring are the main topics of the equipment maintenance section. A preventive maintenance basis was also developed for this report.

EPRI Perspective

The turbine steam seal system prevents steam from leaking into the atmosphere from the high-pressure and intermediate-pressure turbine and prevents air from leaking into the low-pressure turbine. This system must be in operation for a vacuum to be established in the condenser and thus, for the turbine-generator to operate. The steam seal system requires little maintenance and has not proven to be a cause of significant problems over the years. Regular preventive/predictive maintenance functions and condition monitoring are required to ensure the reliability and dependability of the steam seal system.

Keywords

Steam seal

Gland seal

Reliability

Maintenance

Preventive maintenance

Condition monitoring

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1

INTRODUCTION

1.1 Background

Turbines are constructed so that the rotor shaft, which transmits kinetic energy to the generator, passes through the turbine casing. To optimize turbine performance, it is necessary to seal the area where the shaft passes through the casing. This is because the pressure inside the turbine casing is different from the atmospheric pressure outside. A low-pressure (LP) turbine exhausts to a condenser that operates under a vacuum relative to the atmosphere. The pressure inside a high-pressure (HP) turbine or an intermediate-pressure (IP) turbine (an IP turbine is also called a *reheat turbine* [RHT]), however, varies from vacuum during startup to a significant positive pressure above atmospheric level at full load. The actual value of pressure inside an HP or IP turbine casing depends on load. Therefore, all steam turbines—both fossil and nuclear—require gland seals or packings in the areas where the shaft penetrates the casing. These seals or packings minimize leakage and, consequently, maximize the thermal performance of the unit. The steam seal system is connected to the steam seals on the feedwater pump turbines. In addition, leakoff from the turbine valves enters the steam seal system.

In general, large power turbines are designed to be self-sealing at power levels above approximately 40%. *Self-sealing* means that there is a sufficient supply of steam coming from leakoff and extraction steam lines into the steam seal system. No external steam should be coming into a properly functioning steam seal system, with the possible exception of a BWR, when steam might be input to ensure that there is no leakage of radioactive steam into the turbine building. This implies that there are isolation valves that will isolate any source of incoming steam to the steam seal system. It has been demonstrated that isolation valves that do not prevent main steam from flowing into the steam seal system can pass about 1% of the main steam directly back to the condenser. This bypassed steam adversely affects the condenser performance, degrades the seals, and has a significant impact on the plant's heat balance. Test results have documented that main steam leaking into the steam seal system has influenced a plant's heat rate loss on the order of 100 Btu/kWh. Section 8.3 describes troubleshooting and testing to determine if there is leakage into the steam seal system from the main steam system.

Steam leakage is a significant part of the controllable losses in large commercial steam turbines. In most units, condenser vacuum cannot be attained without a properly functioning steam seal system. Due to the radiation consideration, although the leakage of steam from the turbine in a BWR to the atmosphere is of utmost concern, leakage between the turbine casing and the rotor shaft is a concern in any turbine. Experience at power-generating utilities has shown that inadequate sealing and valves requiring cycle isolation can cause power loss and contribute to a

forced outage. It is estimated that an improvement in the heat rate of up to 5% could be achieved by reducing the steam leakage and upgrading the steam seals in the turbines [5]. Similarly, air leakage into the condenser can also be detrimental to power plant operation.

If the steam/gland seal exhauster is not set up properly, steam can flow out from the packing casing along the turbine rotor to the bearings. Steam or water introduced into the turbine bearings will cause contaminant problems in the turbine lubrication system.

To minimize leakage, an elaborate steam seal system is employed to generate the necessary vacuum and pressure chambers inside gland sealing. The system is very similar to that in the turbines used in nuclear and fossil power plants.

Input from EPRI-member utilities indicated the need to address the turbine seal system maintenance issues. This report, which addresses the maintenance of the seal system components, is intended to assist plant maintenance personnel in the identification and resolution of component problems in the turbine steam seal system and to recommend effective preventive maintenance (PM) and condition monitoring (CM). The report is also intended to provide a comprehensive maintenance guide for the turbine steam seal system. The recommendations contained in this report provide the basis for developing suitable PM and predictive maintenance (PdM) programs for the steam seal system components.

Seals and packing describe the devices that minimize leakage in turbomachinery equipment. The term *seals* will be used in this report. The steam seal system is sometimes referred to as the *gland seal(ing) system*. The gland seal system also seals the various turbine valve spindles as well as the rotors. For consistency, the term *steam seal system* will be used throughout this report. *Casing, cylinder, and shell* are the most common terms for the turbine covers. For consistency, the term *turbine casing* is used throughout this report.

The following components of the steam seal system are included in this report:

- Gland seal assembly and shaft sealing
- Steam seal headers
- Regulating valves
- Steam seal inlet valves or shutoff valves
- Swing check valves
- Steam seal diverting valves/spillover station
- Spillover regulating valve
- Steam seal evaporator
- Packing blowdown valves
- Steam seal/gland dampers and bypass valves
- Steam seal exhauster and condenser

- Desuperheater
- Relief valves
- Safety head assembly
- Steam seal strainers
- Auxiliary steam supply
- Steam seal instrumentation

The following systems, subsystems, and components are not included in this report:

- Turbine rotor packing areas
- Packing, casing, and labyrinth seal rings
- Raw or filtered water system
- Condensate system
- Condenser wall penetrations
- Station air supply system for steam seal system valve controls
- Seismic constraints for piping
- Motor operators for valves

1.2 Approach

This report provides power plant personnel with the information necessary to understand the basic principles of the steam seal system. In addition, the report provides a physical description of the steam seal system's major components and their operational characteristics. Also provided is an overview of the past maintenance problems associated with the steam seal system, including associated causes, troubleshooting, and corrective actions taken. The report summarizes the most common failure modes and describes the appropriate PdM and PM techniques. Finally, this report provides information on methods and ideas to optimize the service life and minimize the maintenance costs of the steam seal system.

Recommendations in this report are based on published literature and the experience of the writers as well as the experience and expertise of numerous users and manufacturers. Data sources include the following:

- Power plant maintenance, operating, and engineering personnel
- Turbine-generator manufacturers
- Equipment manufacturers
- The Institute of Nuclear Power Operations (INPO) Nuclear Power Reliability Data System (NPRDS)/Equipment Performance Information Exchange (EPIX) database

- Results of a comprehensive maintenance survey completed by the members of the EPRI Turbine-Generator Users Group
- EPRI publications and other technical publications

The proposed report content and schedule were sent in April 2006 to the EPRI Turbine-Generator Users Group members. The members were asked to provide input for the report and to participate in a technical advisory group (TAG). The TAG for the report consisted of seven utility members. The TAG members provided input for the report, reviewed the first draft, and provided comments.

The conversion factors in Table 1-1 should be used to convert from English to SI units of measurement.

Table 1-1
Conversion Factors

Parameter	English to SI Units
Heat	1 Btu = 3,415 kWh or 9.478×10^{-4} joules (J)
Length	1 in. = 0.0254 m 1 in. = 2.54 cm 1 in. = 25.4 mm 1 in. = 25,400 micron (μm)
	1 ft = 0.3048 m 1 ft = 30.48 cm 1 ft = 304.8 mm 1 ft = 304,800 μm
Pressure	1 in. of water pressure = 0.036128 lb per square inch (psi) 1 in. of mercury (Hg) pressure = 2.036 psi 1 psi = 6.89 kilopascal (kPa) inches water gauge = inches wg psig = psi gauge psia = psi absolute
Temperature	$^{\circ}\text{F} = 1.8 (^{\circ}\text{C}) + 32$
Weight	1 oz. = 28.35 g 1 lb = 0.454 kg
Velocity	1 in/sec = 25.4 cm/sec 1 ft/sec = 0.3048 m/sec

1.3 Organization

The organization of this report is as follows:

- Section 1 provides an introduction and general discussion of the report's background, approach, objectives, and organization.
- Section 2 provides a glossary of terms and acronyms used throughout this report.
- Section 3 provides a basic overview of the functional design and operational aspects of a large steam turbine steam seal system.
- Section 4 provides a technical description of the steam seal components.
- Section 5 addresses a preventive maintenance basis (PM basis) of the steam seal system.
- Section 6 provides PM, PdM, and CM recommendations.
- Section 7 addresses individual component maintenance, including the recommendations for the repair/rebuild/replace of the components based on their condition.
- Section 8 addresses troubleshooting the steam seal system and includes failure modes and causes.
- Section 9 identifies modifications and upgrades that have either been installed by a utility or are recommended by the original equipment manufacturer (OEM).
- Section 10 provides general safety information to be considered when working on a steam seal system.
- Sections 11 and 12 list the references and bibliography for this report.

2

ACRONYMS AND ABBREVIATIONS

°F	degrees Fahrenheit
ΔT	temperature difference
3-D	three-dimensional
ACC	active clearance control (in describing a seal)
ANSI	American National Standards Institute
AOV	air-operated valve
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
aux.	auxiliary
BWR	boiling water reactor
CFD	computational fluid dynamics
cfs	cubic feet per second
CM	condition monitoring
DP	differential pressure
EPIX	Equipment Performance Information Exchange
EPRI	Electric Power Research Institute
ERP	equipment reliability process
ES	extraction steam
fps	feet per second
GADS	Generating Availability Data System
GE	General Electric Company
gpm	gallons per minute
GSS	gland seal system
HP	high-pressure (turbine)
inches Hg vacuum	inches of mercury vacuum
inches wg	inches of water, gauge
INPO	Institute of Nuclear Power Operations
IP	intermediate-pressure (turbine)
ips	inches per second

LP	low-pressure (turbine)
MHI	Mitsubishi Heavy Industries
micron	one one-millionth of a meter (1/1,000,000 or 0.000001 or 10 ⁻⁶ m)
MOV	motor-operated valve
MS	main steam system
MTG	main turbine-generator
MW	megawatt
NEI	Nuclear Energy Institute
NEMA	National Electric Manufacturers Association
NMAC	Nuclear Maintenance Applications Center
NPRDS	Nuclear Plant Reliability Data System
O&M	operations and maintenance
OEM	original equipment manufacturer
OSHA	Occupational Safety and Health Administration
PCV	pressure control valve
PI	pressure indicator
PMP	performance monitoring plan
PMT	post-maintenance test(ing)
PRV	pressure relief valve
PS	pressure switch
psi	pounds per square inch
psia	pounds per square inch, absolute
psig	pounds per square inch, gauge
PSV	pressure safety valve
PWR	pressurized water reactor
RHT	reheat turbine
rpm	revolutions per minute
RTD	resistance temperature detector
SPE	steam packing exhauster
SSE	steam seal evaporator
TC	thermocouple
TCV	temperature control valve
TI	temperature indicator
TS	temperature switch
U.S.	United States

3

STEAM SEAL APPLICATION

3.1 System Description

The main steam turbine converts the thermal energy of steam into kinetic energy of the rotor, which in turn drives the generator. In a typical large fossil power station, the mechanical power is generated by the HP turbine, the IP turbine or RHT, and the LP turbine. Only HP and LP turbines are employed in a typical nuclear power plant. The steam seal system also provides sealing steam to the feedwater pump turbines. Leakoff flows from the turbine valves are received in the steam seal system.

The steam seal system is designed to prevent steam from leaking into the atmosphere from the HP or IP turbine and to prevent air from leaking into the steam path in the LP turbine. Without a system for sealing the rotor shaft, where the shaft penetrates the cylinder, high-pressure steam would escape from the HP and IP turbines, and air would leak into the LP turbine. Both conditions would be unacceptable because of the potential for:

- Inability to start the turbine-generator unit (condenser vacuum cannot be attained)
- Decreased thermal efficiency
- Loss of condenser vacuum during operation (which can cause blade vibration)
- Overheating due to increased windage caused by the loss of vacuum
- Bow of the turbine shaft caused by large temperature differential
- Vibration/rub due to excessive rotor axial elongation caused by hot steam leak
- Damage of sealing and/or bearing surfaces caused by dust or debris
- Contamination in the condensate system
- Steam or water in the turbine bearing oil or pedestal
- Contamination in the lubrication system
- High levels of non-condensable gases in the condensate system
- Uncontrolled radiation risk at the BWR turbine

It would not be possible to establish an adequate condenser vacuum without a steam seal system and, therefore, it would not be possible to start a large turbine. Interlocks and computer logic incorporated in the power plant design would prevent starting the turbine. Eliminating leakage of air into the LP turbine from outside the LP turbine is necessary because the LP turbine exhausts

at the end of the LP shell to a condenser that operates under a vacuum. Eliminating air leakage into the HP and IP turbines during startup and low-load operations is essential to prevent non-condensables from entering the steam path.

In order to optimize the sealing of the shaft where it penetrates the casing, either an elaborate labyrinth seal or a straight shaft seal is employed. A straight shaft seal can also be referred to as a *see-through seal*. Typical, conventional labyrinth seals are discussed in this section. Other, more modern approaches to gland sealing are outlined in Section 9 of this report.

The steam seal system is designed to do the following:

- Seal the shaft where it penetrates the turbine casing
- Seal and isolate each turbine element from atmospheric conditions in order to optimize its thermodynamic performance
- Seal feedwater turbine shafts where they penetrate the casing
- Seal associated turbine valve stems on both the main and feedwater turbines

The portions of the steam seal systems associated with the feedwater turbines, interstage (blade rings/diaphragms) seals, and turbine valves are outside the scope of this report. Only the portion of the steam seal system associated with the leakage around the turbine shaft where it penetrates the turbine casing is addressed in this report. However, when troubleshooting problems with the steam seal system, the connection or ties into the feedwater pump turbine's steam seals should be considered.

In some cases, the HP turbine and the IP turbine/RHT are on a common shaft and located in the same shell. In these applications, the shaft is sealed against internal steam leakage from the HP turbine to the IP turbine/RHT using labyrinth shaft packing, which provides a series of throttlings that minimize steam leakage along the rotating shaft. Figure 3-1 shows a typical labyrinth shaft-packing seal.

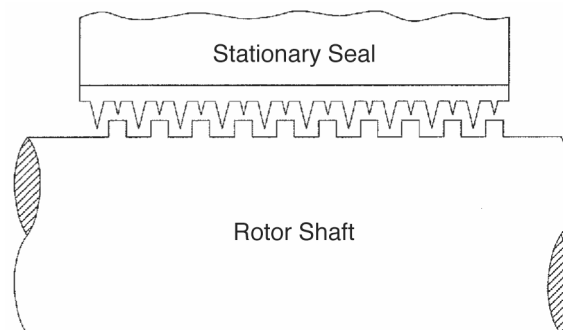


Figure 3-1
Geometry of a Conventional Labyrinth Seal

The seal forces the escaping steam or the incoming air to travel through a long and torturous path, which increases drag and thus reduces leakage. In analytical terms, steam passing through a labyrinth seal is throttled with a resultant pressure loss as it passes through a consecutive series of restrictions.

As an additional improvement, the labyrinth seal is split into two sections and a suction chamber is introduced between the two seal sections, as shown in Figure 3-2.

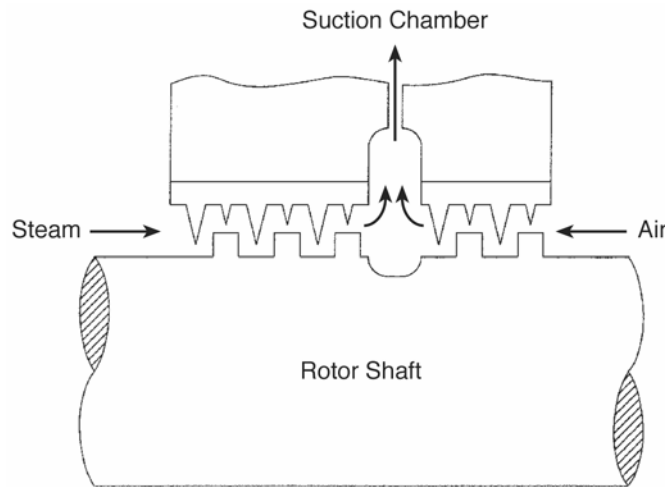


Figure 3-2
Labyrinth Seal with Suction Chamber

The suction chamber, where the pressure is maintained at approximately 12 psia, or -2.3 psi vacuum, draws the high-pressure steam leaking through the labyrinth path. Some system designs maintain the suction chamber at about 10 inches wg below atmospheric pressure. This pressure is set during initial unit startup to a level that just prevents steam leakage from the shaft ends. The pressure is set by adjusting the butterfly valve controls on the gland seal condenser exhaust fan. If the pressure is set too low, steam leaks into the atmosphere and possibly into the bearing pedestals; if it is set too high, oil vapor and non-condensables can be drawn into the glands and into the condenser.

The design shown in Figure 3-2 is not very effective in LP turbines, where the primary objective is to prevent air leakage into the steam. As a further improvement, a three-piece seal is used throughout the LP turbine unit. In this design, in addition to the suction chamber, a pressure chamber is added to the steam seal system (gland seal system), as shown in Figure 3-3. A straight or see-through seal is also used with the addition of a pressure chamber in some LP turbine designs. The low-pressure rotor sealing area might not have lands machined but be a flat, uniform surface.

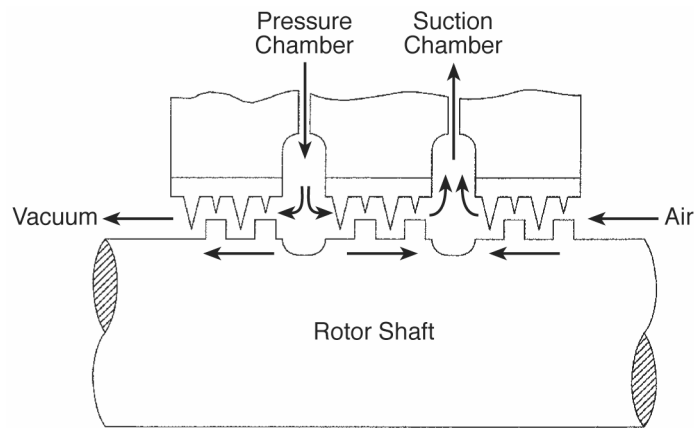


Figure 3-3
Labyrinth Seal with Suction and Pressure Chamber in an LP Turbine

Steam at controlled pressure is supplied to the pressure chamber located between the suction chamber and the turbine exhaust. Consequently, steam from the inboard pressure chamber, where the pressure is set between 2 psi and 5 psi above atmospheric, leaks toward the suction chamber and to some extent, toward the condenser. This steam is subsequently drawn into the suction chamber, as shown in Figure 3-3. Any air that enters from outside is also drawn into the suction chamber. The pressure in the pressure chamber should be as low as practicable, consistent with preventing air leakage into the condenser and minimizing steam leakage into the condenser.

Figure 3-4 illustrates the operation of the three-segment seal in an HP or IP turbine under full load condition. As soon as the pressure inside the turbine exceeds the pressure in the pressure chamber, steam is drawn out of the turbine and into the pressure chamber. Most steam leakage will be drawn from the high-pressure zone into the pressure chamber, as shown in Figure 3-4. However, some steam will continue to leak past the middle section and into the suction chamber, where it will be removed along with the air leaking from outside.

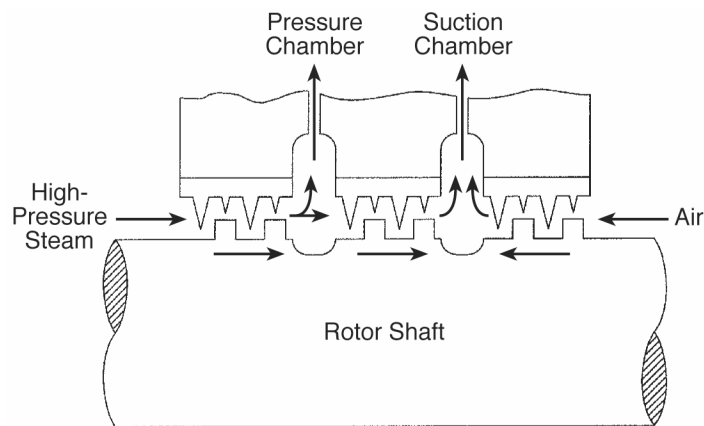


Figure 3-4
Labyrinth Seal with Suction and Pressure Chamber in an HP Turbine at Full Load

Conceptually, each of the turbine manufacturers' steam seal systems is designed to operate in a similar manner. A series of slightly lower and higher concentric diameters that form stepped grooves are machined on the outer diameter of the rotor shaft. The mating stationary seal consists of radially inward-oriented seal strips, which typically alternate between the lower and higher diameters, as illustrated in Figures 3-5 and 3-6 for HP/IP and LP turbines, respectively. Thus, a labyrinth seal is formed. Some manufacturers also insert seals into the shaft surface. Pressure chambers and suction chambers are introduced between the inboard, middle, and outboard seal segments, respectively, as previously explained and shown in Figures 3-5 and 3-6. Typically, the gland seal assembly in the HP and IP turbine consists of two seal ring housing assemblies, whereas a single seal ring housing is used at the exhaust end of the LP turbine. Some HP turbine designs have additional glands to reduce the pressure progressively down to the sealing pressure.

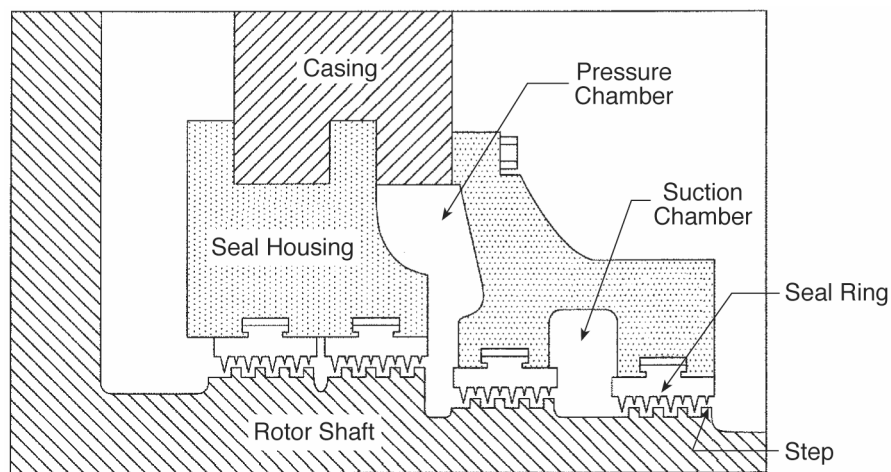


Figure 3-5
Typical Gland Seal in an HP Turbine

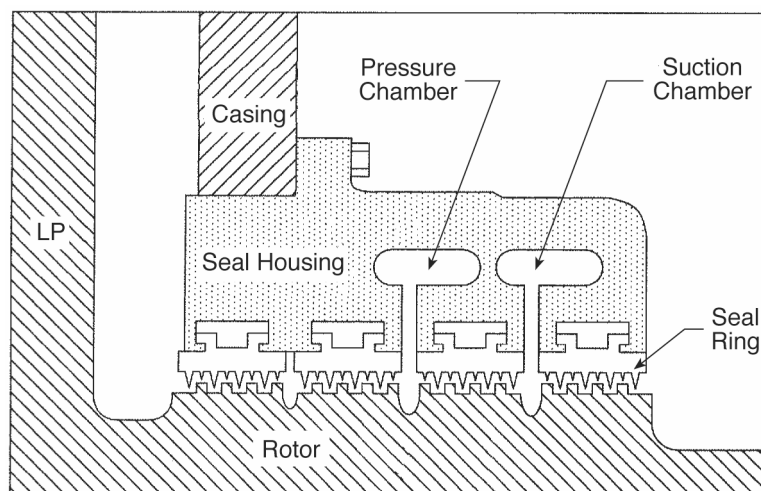


Figure 3-6
Typical Gland Seal in an LP Turbine

Figure 3-7 shows an overview of the rotor shaft area with gland seals exposed.

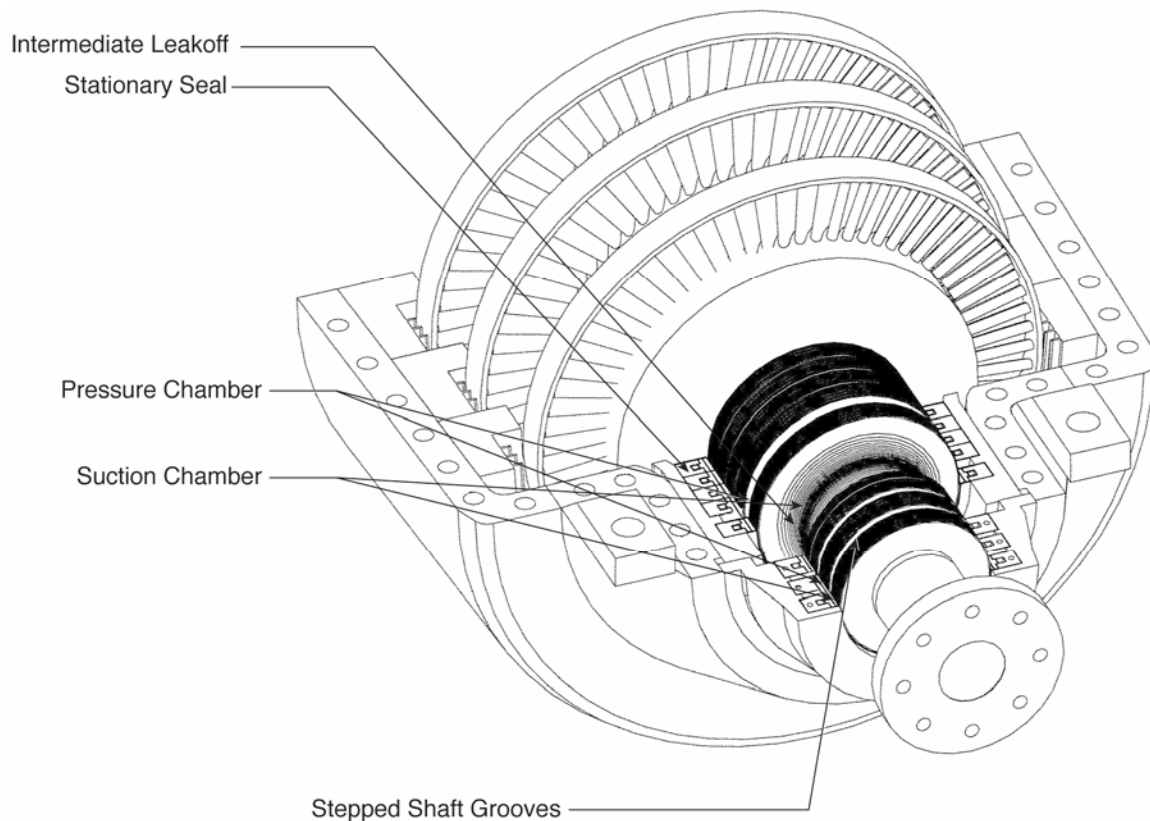


Figure 3-7
Sectional View of the Rotor Shaft Area with Gland Seals Exposed

Figure 3-8 shows a turbine steam seal system in a typical fossil power plant. The steam header supplies steam at pressure slightly above the atmospheric pressure and is controlled by the pressure-regulating system. The pressure at the suction header is maintained slightly below atmospheric pressure and is established by the gland steam condenser and the air exhauster.

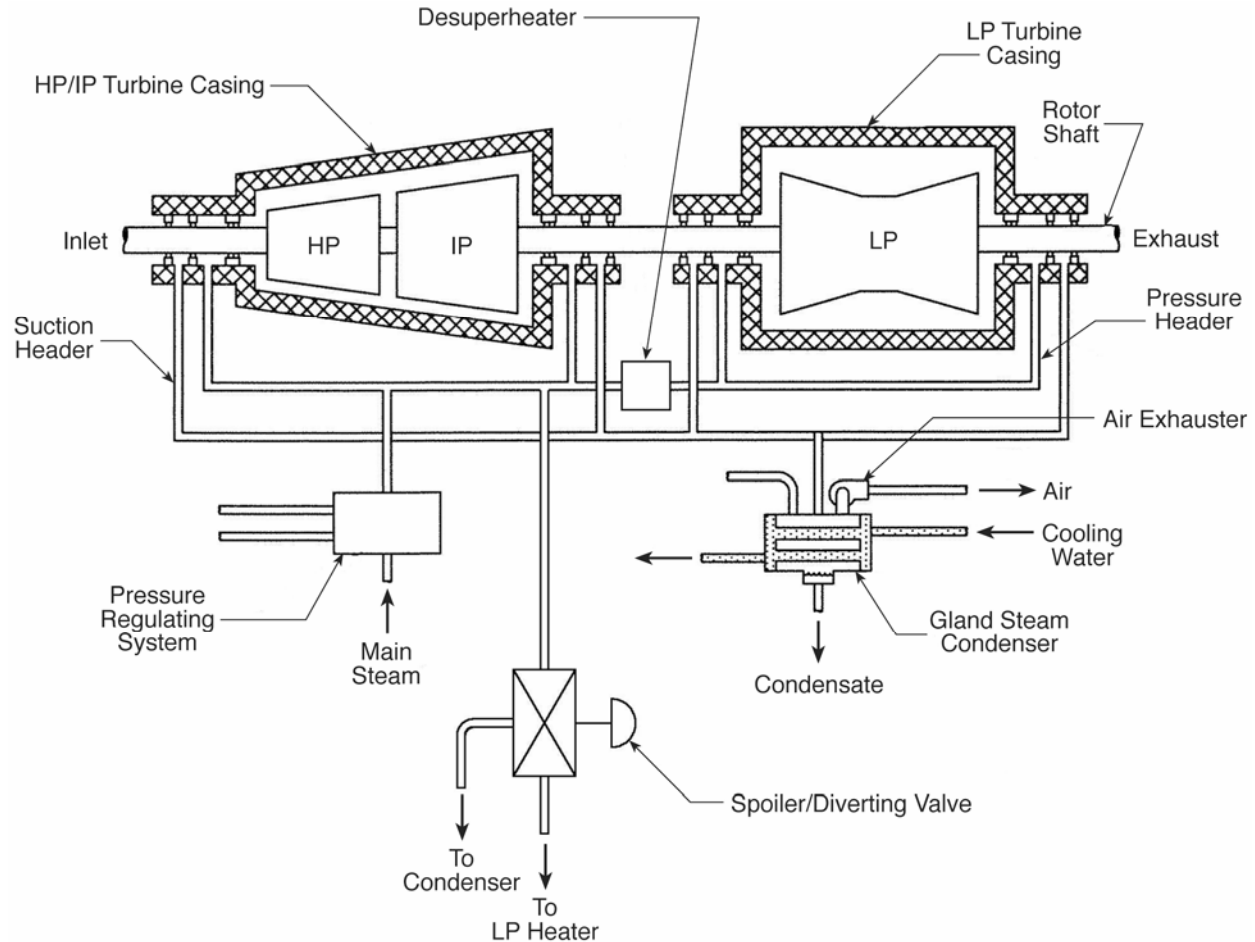


Figure 3-8
Schematic Representation of the Steam Seal System in a Fossil Power Plant

Labyrinth-type shaft packings are used where both the HP and IP turbine/RHT are on the same shaft and in the same shell. This packing will seal against internal steam leakage from the HP to the IP/RHT sections by providing a series of throttlings that limit steam leakage along the rotating shaft to a minimum as the pressure is reduced from the high-pressure space to the low-pressure space. The packing blowdown valve prevents the LP turbine from overspeeding during a turbine trip. Section 4.9 further describes the function of the packing blowdown valve.

Figure 3-9 shows the typical labyrinth-type shaft packing between opposed-flow HP and IP turbine sections on one rotor. This middle packing is considered part of the steam seal system. (If the HP and IP sections are on separate rotors, there will be packing casings on each end of the HP rotor and on each end of the IP rotor.) The addition of a packing blowdown valve is necessary to relieve the steam flow when the turbine is tripped and to prevent an overspeed condition. Following a turbine trip, there is a large volume of high-pressure, high-temperature steam contained in the reheat section of the boiler. The steam flow across the middle packing might be sufficient to cause an overspeed of the IP and LP turbines.

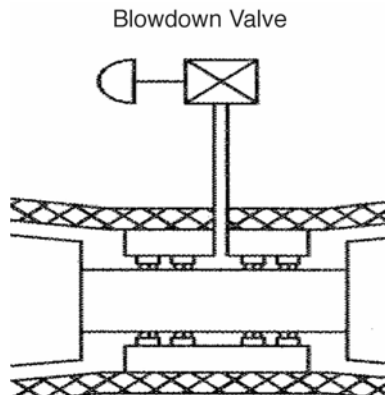


Figure 3-9
Packing Casing Between the HP and IP Opposed-Flow Turbines

To prevent this from happening, an air-operated blowdown valve is installed. The blowdown valve is an air-to-close, spring-to-open valve that will open on a turbine trip. On a signal to open, the solenoid air valve will release the air from the blowdown valve operator, which will open the blowdown valve and release the high-pressure, high-temperature steam from the intermediate packing leakoff to the condenser. The intermediate packing leakoff is shown in Figure 3-7. The blowdown valve discharges directly to the condenser.

Figure 3-10 shows the turbine steam seal system in a typical nuclear unit. In nuclear power plants, turbines operate at temperatures and pressures lower than those in fossil power plants. This necessitates some changes in the steam supply system. The gland steam supply often features two stages: a primary steam supply station takes the main steam from ahead of the turbine stop or throttle valves, and a number of additional supply stations augment the primary pressure control station. In addition, only the HP turbine has the spillover station. Further, the high-pressure leakoff from the main steam valve leads into the HP turbine steam seal system and the pressure header, as shown in Figure 3-10. Finally, because the temperature of the steam supply is lower than that in fossil units, a desuperheater station is not required. Some turbine designs achieve desuperheating by running the gland seal pipes through the condenser steam space so that the exhaust flow provides the necessary cooling.

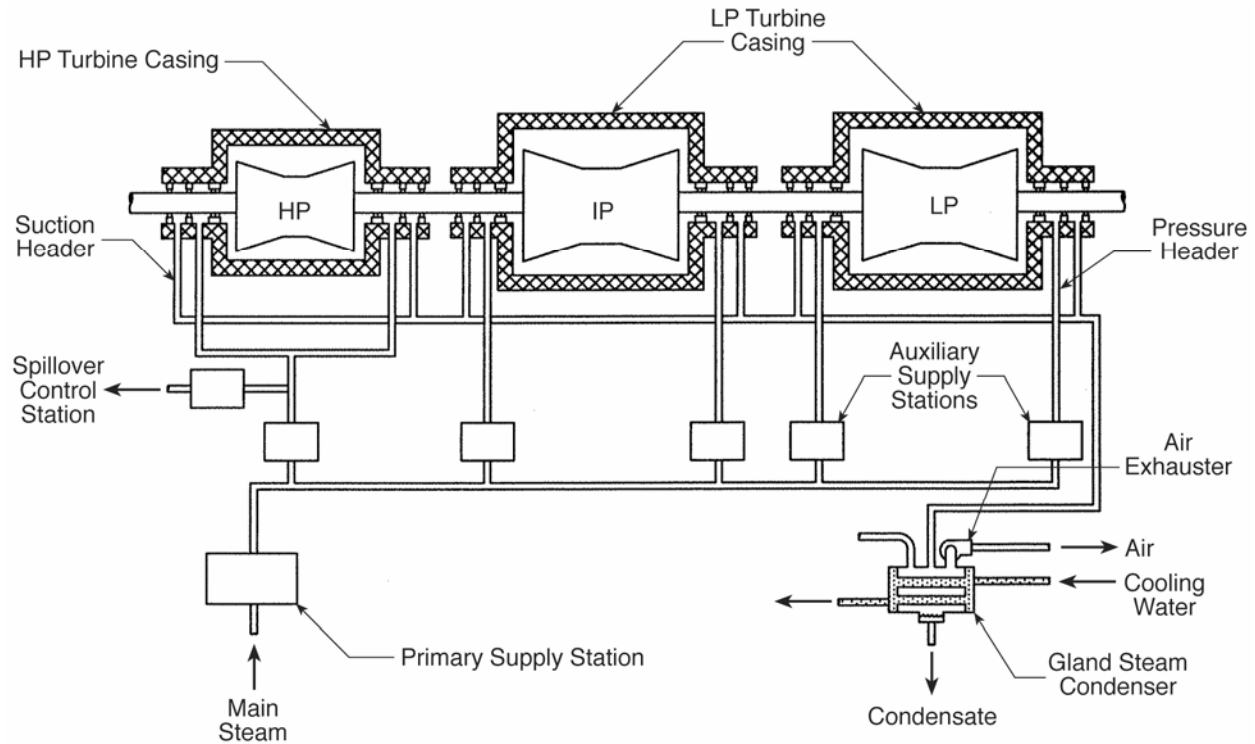


Figure 3-10
Schematic Representation of a Steam Seal System for a Nuclear Turbine

In nuclear power plants of the BWR type, the steam produced in the reactor is the same steam used to turn the turbine. Because the steam might contain some radioactivity, the sealing system is designed to prevent the radioactive steam from going to the steam seal condenser and to the atmosphere. This is accomplished by supplying a separate non-radioactive steam to the gland seals at a pressure greater than the turbine exhaust pressure. As mentioned, the pressure at the LP exhaust is below atmospheric pressure. Therefore, supplying steam at a constant pressure slightly above the atmospheric level to the LP exhaust area prevents a radioactive steam leak. However, the pressure at the HP exhaust area varies with load and, in general, is below the atmospheric pressure at low loads and above the atmospheric pressure at full load.

Again, to prevent a flow of radioactive steam to the atmosphere, the seal system is designed to maintain pressure in the supply zone/pressure header that is higher than the high-pressure exhaust and to do so under all operating conditions. A submerged tube evaporator is used as a source of clean steam for the steam seal system. Steam from the first HP extraction is used to supply the tube side of the submerged tube evaporator while the water for the casing side is fed from the condensate discharge. In addition, each control valve is equipped with an isolation valve and a bypass valve to allow a manual operation as a clean system in the event of a control valve failure. Furthermore, should there be a malfunction of the evaporator, a bypass system is added to provide for sealing of the glands with radioactive steam.

Figure 3-11 illustrates schematically the typical steam seal system in its entirety. Steam above atmospheric pressure is supplied to the pressure chamber. The steam supply system consists of the steam header, the steam supply and spillover stations that make up the pressure-regulating system, the desuperheater station, the gland steam strainers, the safety relief valve, and the safety head disk. The suction side of the steam seal system operates below the atmospheric pressure. The system consists of the suction header and the gland steam condenser. Both the steam header and the suction header are typically located beneath the turbine floor.

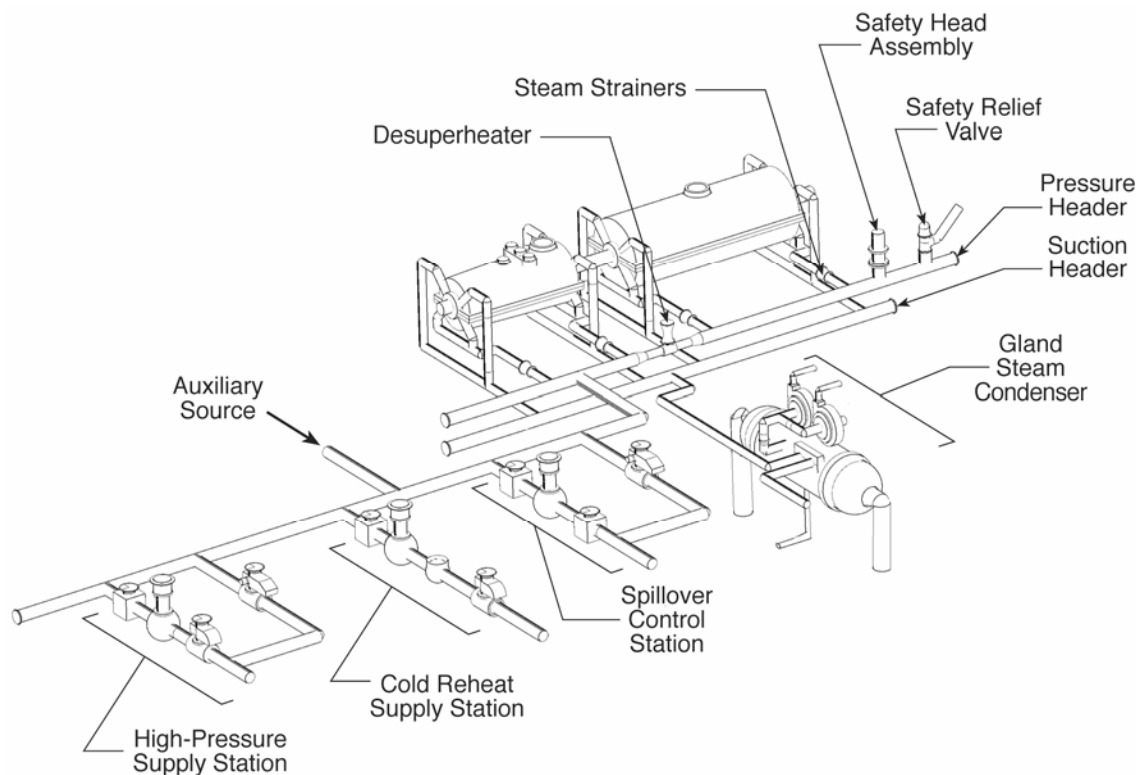


Figure 3-11
Schematic Representation of the Steam Seal System

It should be noted that the steam seal piping system contains steam, water, and a combination of steam and water. Depending on the turbine operating mode, there might be a two-phase flow of water and steam in the piping. Water hammers have been known to occur in this piping.

3.1.1 Pressure System

The supply stations draw steam from several sources. High steam pressure is usually drawn directly from the boiler, before the turbine stop valves, during a startup. To improve plant performance during normal operation, the cold reheat station typically supplies steam to the header. However, in a BWR plant, steam from an evaporator is used during normal operation. Depending on the particular plant design, there might also be an auxiliary supply station. Each control station includes a primary regulating valve and two backup shutoff valves in series. The

regulating valve is usually either an air-operated valve (AOV) or oil-controlled valve. One of the shutoff valves is typically motor-operated. Additionally, the high-pressure and the spillover stations feature motor-operated bypass valves that are employed in parallel with the regulating valve, as shown in Figure 3-11. A bypass line is not required for the cold reheat supply station because sealing can be provided through the HP supply valve. To prevent reverse flow from the steam header, the cold reheat station is also equipped with a swing check valve.

Under normal operating conditions, steam is supplied to the steam header through open regulating valves at the supply stations. However, if the pressure at the header increases above the normal level, the normally closed pressure-sensing regulating valve in the spillover station will open. This will allow the excess steam to escape to the condenser or to a heater. As a safety precaution, the supply header can also feature a safety relief valve. A rupture disk on the supply header serves as a final safety mechanism.

Typically, the temperature difference between the sealing steam and the turbine rotor in the HP/RHT-IP gland area should be less than 200°F. The temperature of the sealing steam supplied to LP turbine glands should be maintained between 250°F and 350°F. To prevent high-temperature steam from entering the LP turbine gland area, a desuperheater is added to the steam header before the steam enters the LP turbine gland area. The desuperheater cools the steam by spraying condensate water into the steam header. In addition, steam strainers are inserted into the supply lines to filter out any contaminants that might enter the gland areas.

3.1.2 Suction System

The steam seal suction system is outlined in Figure 3-12. As mentioned, the suction header supplies a small vacuum for the steam seal system. It does so by delivering the mixture of steam and air leakage from the gland seals to the gland seal condenser. The condenser for the steam seal system is designed to maintain pressure below atmospheric pressure in the suction header. The vacuum is maintained by the action of exhausters fans, and varying the opening of the butterfly valve controls the actual vacuum level. As the steam passes over the condenser pipes, the steam condenses to water that in turn is returned to the main condenser hotwell. The condensate from the main condenser system serves as cooling water. The air that passes through the steam seal system condenser is released to the atmosphere by the exhausters fans.

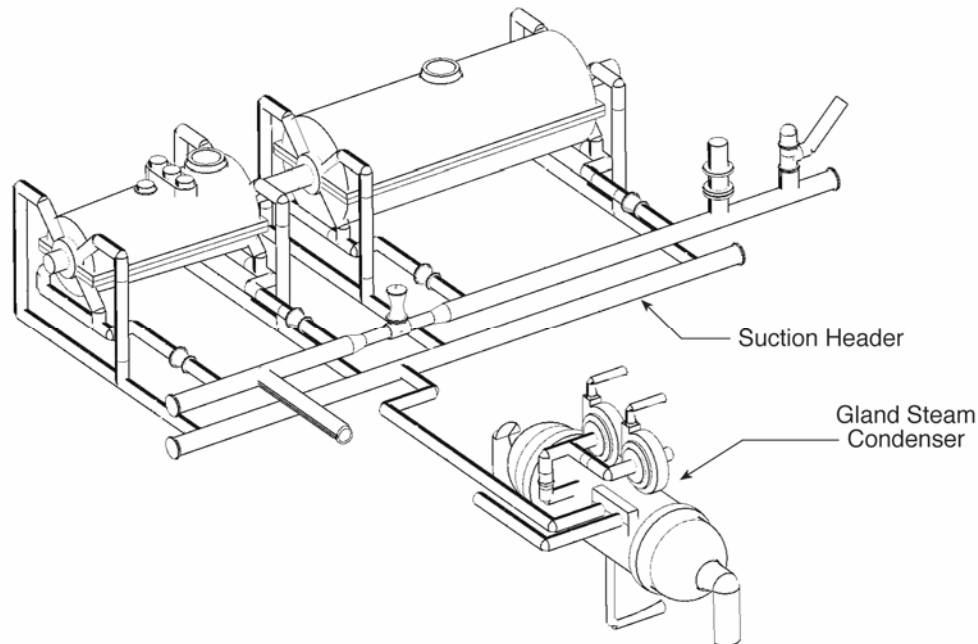


Figure 3-12
Steam Seal Suction System

In general, the suction chamber is outboard or downstream, whereas the pressure chamber is inboard or upstream of the gland sealing area, as shown in Figures 3-5 and 3-6.

3.2 System Operation

In general, the steam seal system must be operational in order to start the unit. Vacuum must be established inside the turbine casings before the unit can be started. This is normally accomplished on turning gear operation while water circulation is initiated through the main condenser. The condensate pump is started concurrently to push cooling water into the steam seal system condenser. Subsequently, steam is diverted through the steam supply system into the gland areas while the high-pressure-regulating valve maintains adequate header pressure. During pre-start, both the cold reheat and the high-pressure-regulating valves are wide open, whereas the swing check valve in the cold reheat station prevents reverse steam flow from the pressure header. Figure 3-13 illustrates schematically the steam seal system operation during a pre-start.

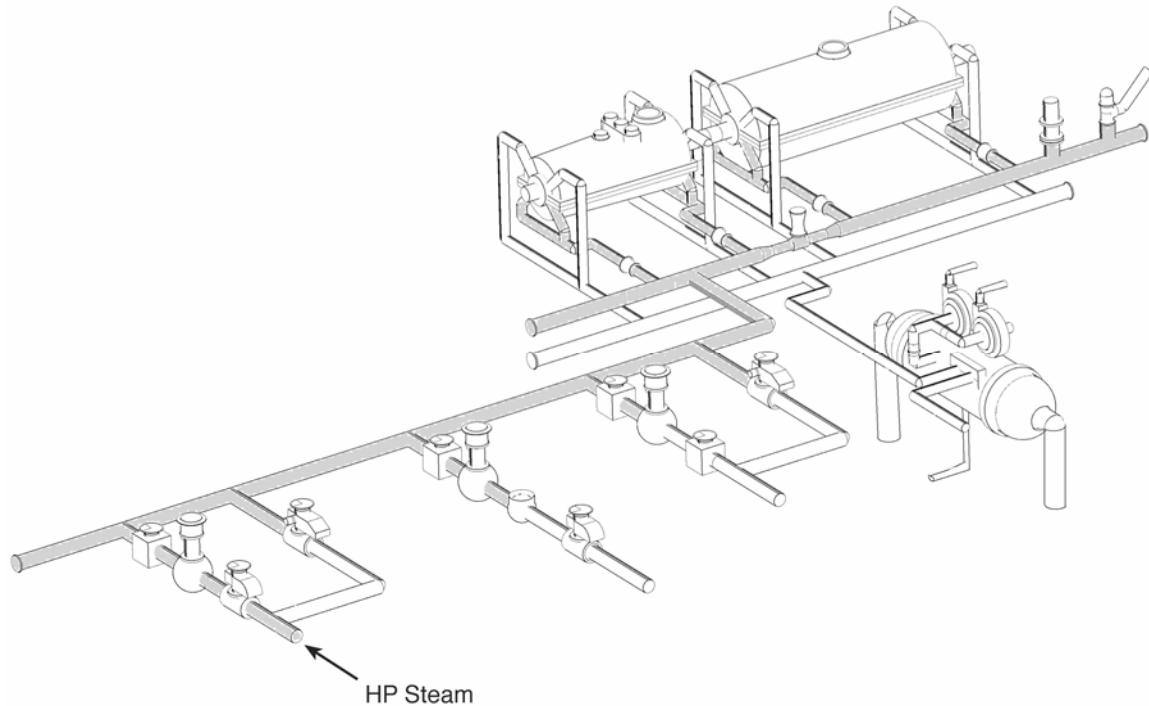


Figure 3-13
Operation of the Steam Seal System During Startup

As the pressure increases in the pressure header, the exhaustor fans in the steam seal system condenser are turned on to prevent steam leakage to the atmosphere. Thus, vacuum is established in all turbine elements. When vacuum has been established in the main condenser, the rotor can be accelerated to the rated speed. With increase in load and cold reheat pressure, the swing check valve in the cold reheat station is opened, allowing cold reheat steam into the header. The high-pressure-regulating valve closes at a predetermined pressure. Some turbine designs use a single integrated controller that controls the main steam supply, the cold reheat supply, and the spillover valves. This integrated controller provides for a progressive change-over from one to another rather than at a predetermined pressure. Drawing steam from the HP turbine exhaust is more economical. With further load increase, the steam pressure inside the HP turbine exceeds the pressure chamber and the steam supply header. Consequently, steam will start leaking from the turbine through the inner gland seal segment into the pressure chamber and, eventually into the steam supply header. This is referred to as a *self-sealing* condition and is usually reached below 25% of rated load. At this point, steam from the HP turbine, combined with the steam from the cold reheat station, supplies the LP gland seal pressure chamber. This condition is shown in Figure 3-14.

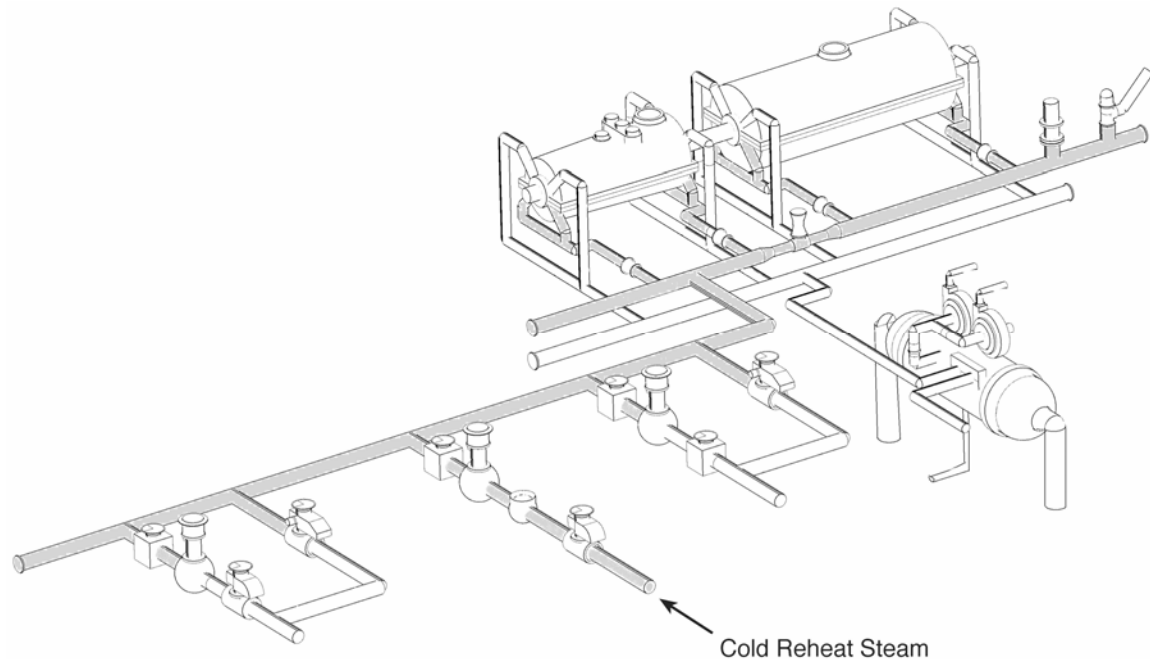


Figure 3-14
Operation of the Steam Seal System at Low Load

As the load and the pressure inside the HP turbine increase even further, the steam flow from the HP turbine into the steam supply header also increases. Typically, the temperature difference between the sealing steam and the turbine rotor in the HP/RHT-IP gland area should be less than 200°F. At some predetermined pressure, or if an integrated controller is controlling, the cold reheat regulating valve will close. If the pressure increases even further, the spillover regulating valve will open, venting some steam to the main condenser. This usually happens at approximately one-half load. Some manufacturers provide a single diverting valve that shuts the cold reheat steam supply and redirects the excess steam to the extraction heater or the condenser. (From a cycle efficiency standpoint, it is best to discharge this steam to the extraction line.) The steam supply at the steam seal system under full load is outlined schematically in Figure 3-15.

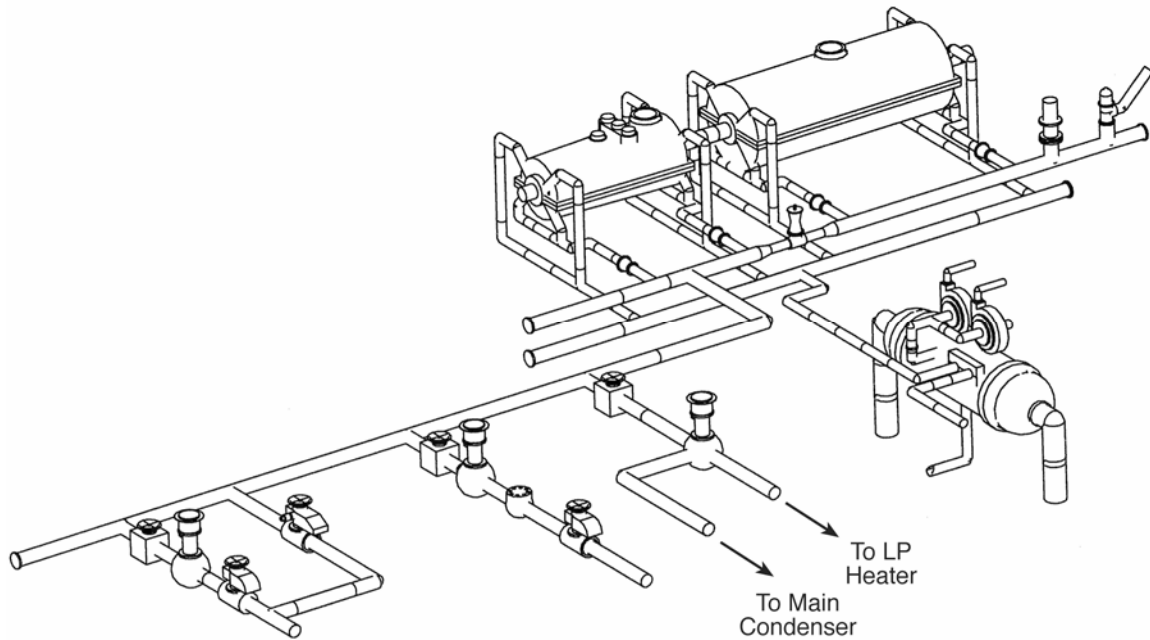


Figure 3-15
Operation of the Steam Seal System at Full Load

In summary, the steam seal system should be in operation at all times when:

- There is vacuum in the main condenser.
- Turbine temperature is above the ambient temperature.
- Either the turning gear or steam is rotating the turbine. This should apply only if the unit is being prepared for startup. If the turbine has been shut down and is scheduled for maintenance, it can remain on gear without the steam seal system in service.

The steam seal system should not be in service when the turbine shaft is stationary.

The temperature difference between the sealing steam and rotor surface can vary under different operating conditions. A large temperature difference will cause thermal cracking. Thus, to protect against rotor damage in gland seal areas, the difference between sealing steam temperature and the rotor surface should be kept to a minimum during startup and shutdown. To provide an assessment of potential damage, some manufacturers supply a curve showing a number of cycles that will initiate thermal cracking for a given temperature difference. This is explained further in Section 6 of this report.

Sealing steam should not be applied to a turbine shaft for a long period of time when the unit is stationary. This is because in addition to thermal cracking, the hot steam can also result in unacceptable thermal expansion and/or bowing of the shaft. A bowed rotor is eccentric and, in general, cannot be safely operated. Temporary or elastic rotor deformation can result from a short exposure of the rotor to steam at a temperature that exceeds normal operating temperature. Elastic deformation/bow can be corrected by turning the rotor on a turning gear until the bowing is rolled out and the rotor is straight.

4

TECHNICAL DESCRIPTION OF STEAM SEAL COMPONENTS

4.1 Gland Seal Assembly and Shaft Sealing

Gland seal assemblies are installed at each end of a steam turbine. Typically, gland seal assemblies that are installed at the ends of the HP/IP turbine element consist of two seal ring housing assemblies. A pressure chamber is formed between the two assemblies, as shown in Figure 3-5. The suction chamber is built into the outer seal ring assembly. On the LP turbine element, however, the gland seal assemblies are often made up of a single seal ring housing with both the suction and pressure chambers formed integrally in it, as illustrated in Figure 3-6. In general, the steam chamber is located adjacent to a turbine, and the suction or vacuum chamber is located further outside, as illustrated in Figures 3-5 and 3-6.

Modern gland sealing areas consist of a series of concentric high and low cylindrical surfaces that form stepped grooves on the outer periphery of the rotor shaft, as illustrated in Figures 3-5, 3-6, and 3-7. (Some designs do not use steps and seal on a uniform cylindrical surface.) Stationary seals are staked in the T-shaped seal rings that in turn are engaged in the stationary seal housing. (In some cases, the seals can be manufactured to be integral with the rings.) Typically, there is a small clearance of 0.01–0.03 in. between the ends of the seal strips and the outer surface of the rotor shaft. Some seals are designed to compensate for rotor sag, that is, with equal clearance on each side but biased in the vertical direction. Springs are employed to provide a controlled radial force and thus ensure that the seals operate close to the rotor surface under a range of operating conditions. The springs will allow the seal rings to retract during transient operations at low loads with minimum damage to the rotor surface. In general, the seal strips are made from a soft material. This is because if a rub occurs, the seal strips should wear without galling the surface of the rotor and without causing excessive surface damage/vibration due to local overheating.

4.2 Steam Seal Headers

The pressurized steam supply line that connects the pressure-regulating system to each gland assembly is called the *steam header*. The pressure header consists of the piping and valves, which, during unit operation, supply the required steam slightly above the atmospheric pressure to the HP turbine, IP turbine, and LP turbine gland seal areas (see Figures 3-5 and 3-6). The pressure-regulating system controls the exact steam pressure. The pressure header supplies steam from primary and auxiliary sources under low load and allows reverse flow under full-load conditions.

Similarly, the suction header maintains vacuum slightly below the atmospheric pressure. The suction header draws a mixture of steam and air from the gland seals and diverts it to the steam seal condenser, outlined in Section 4.11.

In addition to minimizing steam leakage around the rotor shafts, the turbine sealing system also controls steam leakage from the throttle and governor valve stems and reheat and interceptor valves. However, this report addresses only the sealing steam of the main turbine packing glands.

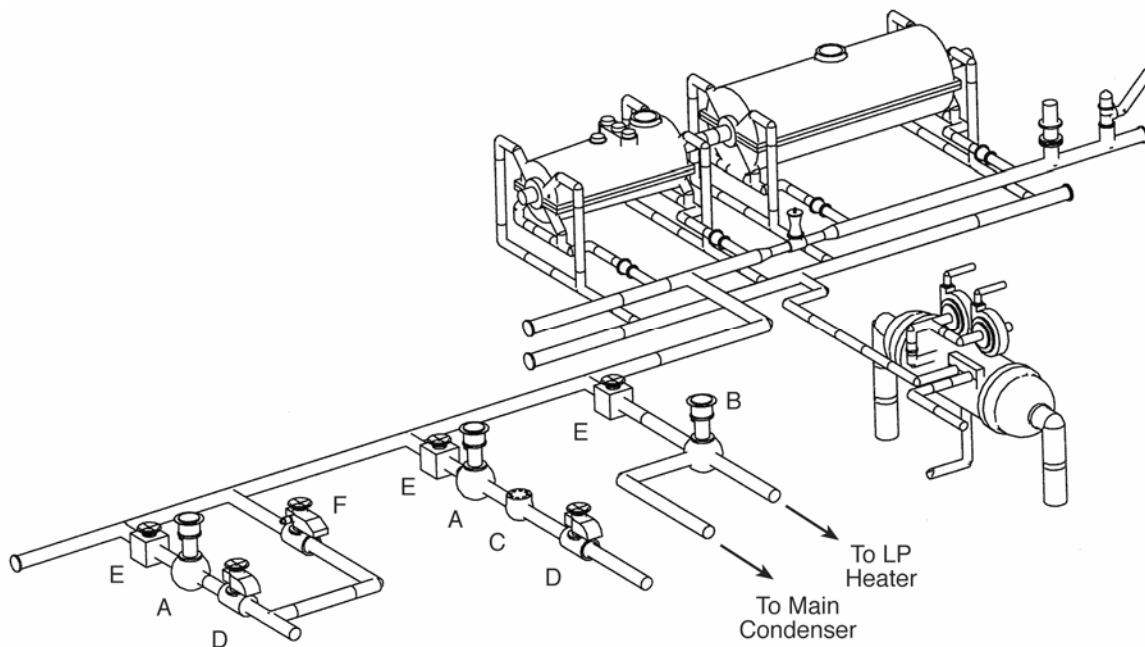
Typically, carbon steel piping is used for the pressure and suction headers. Carbon steel is recommended by the American Society of Mechanical Engineers (ASME) Power Piping Code B31.1 for temperatures below 800°F. Higher temperature materials, such as stainless steel and chrome moly alloys, are sometimes necessary in fossil steam seal systems. The stainless steel and chrome moly materials can be used where pipe erosion has been a problem.

It should be noted that insulation on the steam seal piping is required on some areas and not on others. Over the years, insulation has been removed, replaced, and added. It is recommended that the original construction prints be consulted to determine if insulation is needed.

In general, the piping leading to the pressure casings should be insulated. The lines going to the exhauster and to the condenser should not be insulated. In addition, the lines in the condenser for the low-pressure packings should not be insulated.

4.3 Regulating Valves

Figure 4-1 identifies some of the valves associated with the steam seal system. Next, the valves are discussed in further detail.



Letter Identifier	Valve Function
A	Steam seal regulating valve open under low load
B	Regulating valve, called <i>diverting valve</i> , which is open under full load
C	Swing check valve
D	Motor-operated shutoff valve, also called <i>steam seal inlet valve</i>
E	Manual shutoff valve
F	Motor-operated bypass valve

Figure 4-1
Identification of Selected Valves in the Steam Seal System

Steam to the supply stations comes from several sources. A high steam pressure is usually drawn directly from before the turbine stop valves during startup. During normal operation at low load, the cold reheat station supplies the steam to the pressure header from HP exhaust. Depending on the particular plant design, there might also be an auxiliary steam supply station.

Each control station includes a primary regulating valve. The regulating valve is typically an air-operated diaphragm control valve or a direct acting back-pressure-regulating valve that is operated by the steam it controls. The regulating valve is sometimes referred to as a *feed valve*. Each turbine supplier has a different nomenclature and application for the subject valves. Sometimes, the same manufacturer might even use different nomenclature that varies with the age or application of the equipment.

In some designs, steam is directed to each LP turbine through its dedicated regulating valve. Another regulating valve controls the steam flow to the HP/RHT-IP element, and another regulating valve reduces steam pressure in the pressure header. In a different configuration, there is a regulating valve for each of the auxiliary steam supply stations, and additional regulating valves are associated with the steam evaporator.

A schematic outline of a regulating valve is illustrated in Figure 4-2.

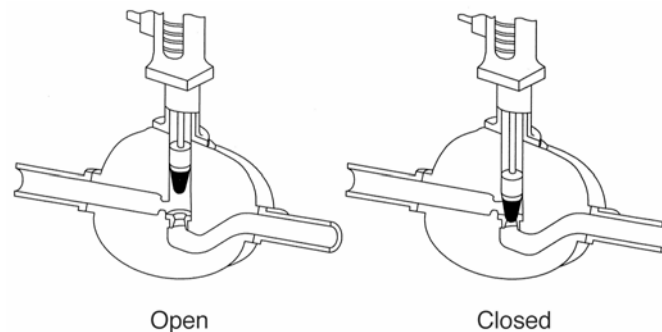


Figure 4-2
Open and Closed Positions of a Regulating Valve

4.4 Steam Seal Inlet Valves or Shutoff Valves

Steam seal inlet valves are typically motor-operated valves (MOVs) that isolate the steam seal system from the source of steam, usually the boiler or the HP turbine exhaust. If an additional steam supply is included in the steam seal system, an inlet valve will isolate each of the different steam sources. Some manufacturers incorporate manual inlet valves in series with the motor-operated ones. The steam seal inlet valves are used to control which source of steam to the steam seal system is used.

The steam seal inlet valves are also known as *shutoff valves*. They are shown conceptually in Figure 4-1.

4.5 Swing Check Valve

Some manufacturers use a swing check valve in the cold reheat station. Its typical operation, indicating open and closed position, is illustrated in Figure 4-3. The swing check valve in the cold reheat station prevents reverse steam flow from the header.

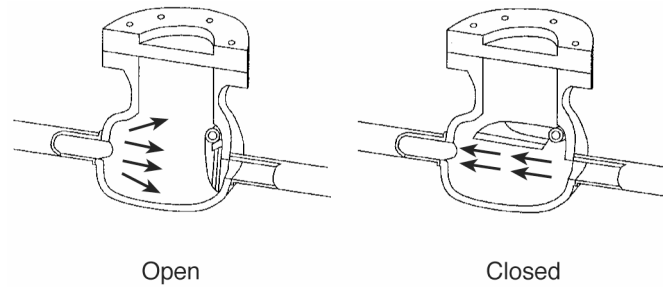


Figure 4-3
Open and Closed Position of the Swing Check Valve

4.6 Steam Seal Diverting Valves/Spillover Station

As the unit reaches higher loads of approximately 50% power level, the steam supply from the HP turbine, and, ultimately, the IP turbine (if one is installed) exceeds the requirements of the steam seal system. There are a number of different approaches to prevent excessive steam pressure in the pressure header. To divert the excess steam under a full operating condition, a three-way, air-operated steam seal diverting valve might be provided. The steam seal diverting valve is constructed as though it were two butterfly valves linked together and operated by a single air operator. One butterfly valve is in the open position, and the other is in the closed position. When air is supplied to the diaphragm in the air operator, the butterfly valve directing the steam to the extraction line opens, and the butterfly valve directing steam to the condenser is closed. On loss of air pressure, the spring in the air operator forces the butterfly valve directing steam to the condenser to open and the butterfly valve to the extraction steam line to close. The spring discharges excess steam to an LP turbine extraction line or to a condenser.

Alternatively, a more elaborate spillover station, outlined in Figure 4-1, might be incorporated. As the unit load and pressure in the pressure header increase, the pressure-sensing regulating valve in the cold reheat station closes. At the same time, a similar pressure-sensing valve in the spillover station opens. The spillover station is typically designed to open at 4 psig.

As a further improvement to the spillover station design, manual shutoff valves are added in series to prevent a malfunction of the spillover assembly. For additional insurance, an MOV is added in parallel, as shown in Figure 4-1.

The steam from the diverting valve/spillover station is directed either to the main condenser or the low-pressure extraction heater. From a heat balance consideration, it is better to dump the excess steam from the steam seal system back into the extraction steam lines.

Reverse steam flow in the pressure header can damage the LP turbine. The instrumentation in the extraction steam lines is designed to prevent this condition. In addition, some manufacturers provide a swing check valve, outlined in Section 4.5.

Under abnormal operating conditions, such as an extraction heater being out of service or a turbine trip in a fossil unit at full load, the temperature of the steam flowing through the diverting valve can reach 750°F. This hot steam is diverted to the extraction heater, which contains steam at substantially lower temperature. However, because the volume of the hot steam is small, the steam will dissipate heat before it reaches the extraction heater.

Under abnormal conditions at full load, a back flow of the steam at 750°F can occur. As mentioned, the LP turbine is not designed for steam flow at 750°F. A large quantity of hot steam at this temperature could cause thermal distortion of the casing and/or the diaphragms. Thermal distortion of a diaphragm can cause a rub. The hot steam could also damage the turbine rotor. To prevent the potential for damage, the diverting valve is designed to redirect the hot steam from the extraction line to the condenser.

4.7 Spillover Regulating Valve

When the high-pressure and cold reheat regulating valves close, the spillover control valve opens, preventing a buildup of excessive pressure in the pressure system. Steam that passes through the spillover regulating valve is diverted to the main condenser or the low-pressure extraction heater.

4.8 Steam Seal Evaporator

A steam seal evaporator is one of several alternative sources of steam used to supply a steam seal system. Steam seal evaporators are most commonly used in a BWR application and, when installed, they are considered the primary source of sealing steam.

An evaporator is the steam seal system component that converts water into steam. Typically, it heats water to the boiling point in a heat exchanger. In a turbine steam seal system, low-pressure extraction steam or main steam is used to boil condensate water on the shell side of the steam seal evaporator. Consequently, the evaporator generates the low-pressure steam necessary for the steam seal system. Regulated main steam in controlled quantity and pressure is used to boil the condensate during startup and at low power levels. The main steam pressure is controlled to prevent damage to the steam seal evaporator tubes. Unregulated extraction steam is used to boil the condensate at higher power levels. In a BWR application, steam from the steam seal evaporator is preferred over main steam for the steam seal system. This is because feeding the main steam to the steam seal system will cause higher local radiation levels and has the potential to leak radioactive steam to the environment.

4.9 Packing Blowdown Valves

Some manufacturers provide steam seal packing blowdown valves. These valves are supplied for an opposed-flow HP and IP turbine section on one rotor. During normal operation, these valves are kept closed by the atmospheric pressure. When required, a spring force opens the valves.

When a turbine with a reheat/intermediate section is tripped and the control and intercept valves close, a significant amount of high-temperature, high-pressure steam remains in the HP turbine. Potentially, this steam could force its way across the packing area between the HP and IP turbines (opposed flow with a packing area between the entrance to the HP and IP turbine sections) and reach the IP turbine. From the IP turbine, there are no valves isolating the LP turbine. This flow from the HP turbine to the IP and LP turbines could cause an overspeed

condition that could damage the turbine. The steam seal packing blowdown valves are designed to prevent this condition. The valves will open when the intercept valves close during a turbine trip. Thus, steam at high pressure and temperature can be diverted directly to the condenser while the unit is tripped.

4.10 Bypass Valves

The high-pressure control station features a bypass valve connected in parallel to the regulating valve, as shown in Figure 4-1. The bypass valve is a motor-operated or manually operated backup valve. Some manufacturers design a spillover station that also includes a motor-operated bypass valve.

4.11 Steam Seal Exhauster and Condenser

As described in Section 3, the suction header supplies vacuum to the gland seals and delivers a mixture of steam and air from the gland seals to the steam seal condenser. In addition, the condenser is also connected to another circuit that pulls steam and air from the main steam valve stems. The combined mixture of steam and air is drawn into the condenser by the exhauster fans. The pressure level in the condenser is controlled by the opening of a butterfly valve in the inlet line to the exhauster fans, as outlined in Figure 4-4.

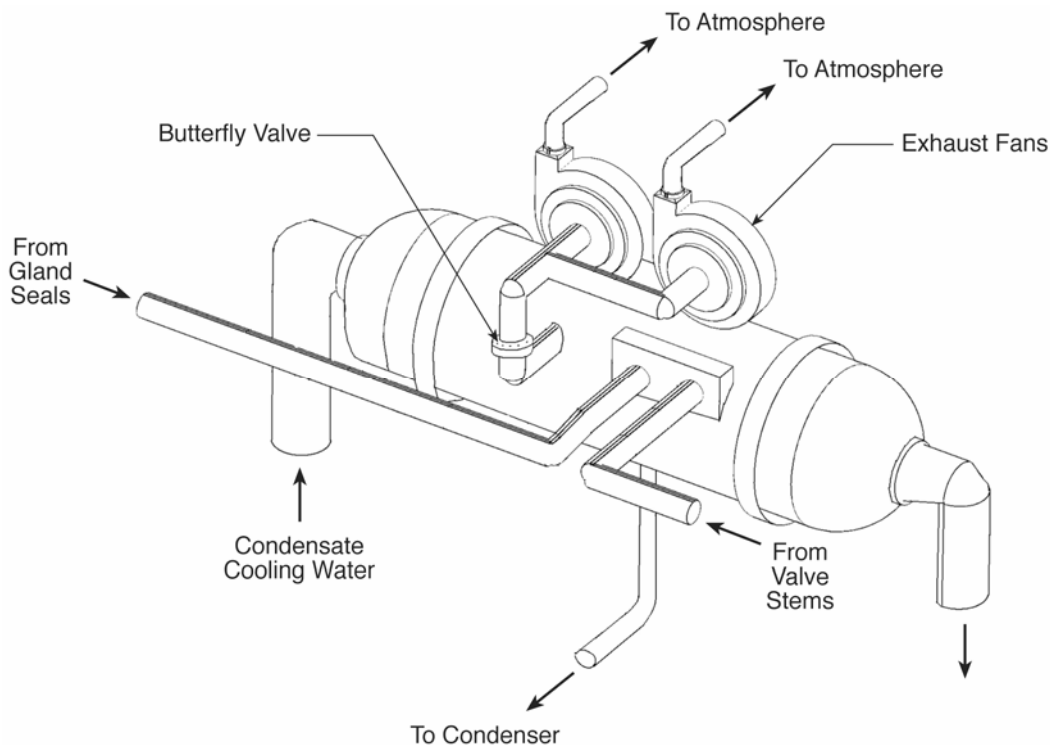


Figure 4-4
Steam Seal System Condenser and Exhauster

As the mixture passes over the condenser pipes, the air is exhausted to the atmosphere by the exhausters fans. The steam condenses to water that is returned to the hotwell of the condenser. Condensate from the main condenser is typically used as a cooling medium in the heat exchanger of the condenser. Filtered water can be used in fossil power plants.

4.12 Desuperheater

As mentioned, both the pressure header and the suction header are typically located beneath the turbine floor. In addition, in a fossil unit, a portion of the steam seal header goes through the exhaust hood or condenser wall. Typically, the temperature difference between the sealing steam and the turbine rotor in the HP-RHT/IP gland area should be less than 200°F. This results in a better match between the temperatures of the steam in the pressure header and the rotor shaft. This approach is not necessary on a nuclear unit where the sealing steam is at the saturation temperature.

The sources of steam in the pressure header are from the main inlet, the cold reheat, or, at high load, the HP and IP turbines. All sources are very hot. Exposing the LP gland area to hot steam could cause thermal cracking. Therefore, a desuperheater spray nozzle is added to the pressure header. The function of the LP gland desuperheater is to limit the temperature of sealing steam in the LP gland areas to approximately 350°F. The desuperheater cools the steam by spraying condensate water into the supply line before it reaches the LP gland area. A typical desuperheater consists of venturi pipe that contains the water spray nozzle, air-operated water control valve, temperature-operated pilot valve, and air-pressure-reducing valve. A schematic outline of the typical operation of the desuperheater spray nozzle is shown in Figure 4-5.

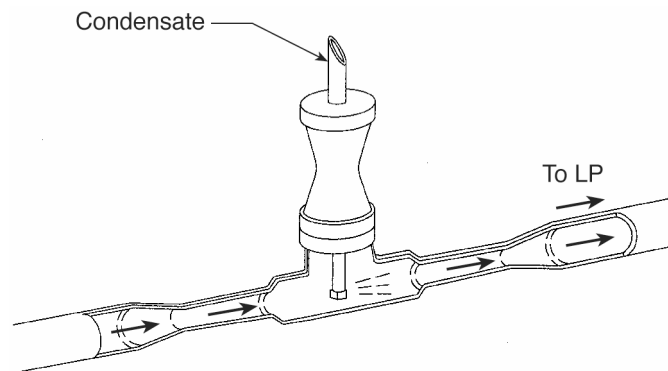


Figure 4-5
Operation of a Desuperheater

4.13 Relief Valves

Under normal operating conditions, steam is supplied to the pressure header through open regulating valve(s) at the supply stations. As the pressure at the header increases, the pressure-sensing regulating valve in the spillover station opens, or, for some manufacturers, the diverting valve redirects the steam toward the extraction heater. As an additional safety precaution to prevent excessive pressure in the pressure header, the supply header can also feature a safety relief valve(s), as identified in Figure 4-1. Typically, the relief valve is a direct-pressure-actuated relieving valve characterized by pop action. Relief valves can be positioned throughout the steam seal system and are designed to protect the steam seal system from exceeding the design pressure of the piping.

4.14 Safety Head Assembly

As an additional precaution, the safety head assembly shown in Figure 4-6 can supplement the safety relief valve outlined in Section 4.13. The safety head assembly incorporates a rupture disk that will rupture if the pressure in the pressure header exceeds 100 psi over the atmospheric pressure. The pressure disk must be replaced after actuation.

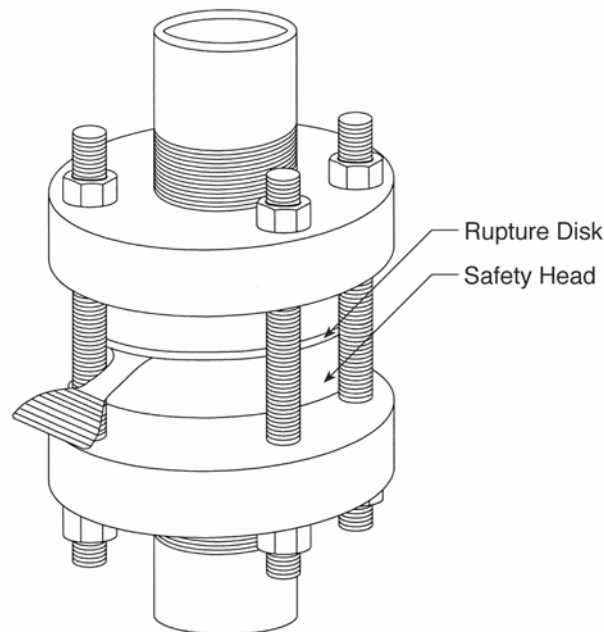


Figure 4-6
Safety Head Assembly

4.15 Steam Seal Strainers

Steam seal strainers can be installed in the supply line to the steam seal glands in order to prevent any debris or foreign particles from entering the packing glands and damaging the area of the steam seals. The strainers are usually Y-pattern flanged strainers (that is, are inclined at approximately 45° to the direction of steam flow). This orientation provides for easy access and at the same time, reduces flow turbulence when compared to the vertical orientation. One alternative orientation is the Y section angled down so that the particles do not fall back into the flow stream, thereby preventing screen erosion. Typically, the filter features a 0.02-in. stainless steel screen. Figure 4-7 conceptually outlines the steam strainer configuration.

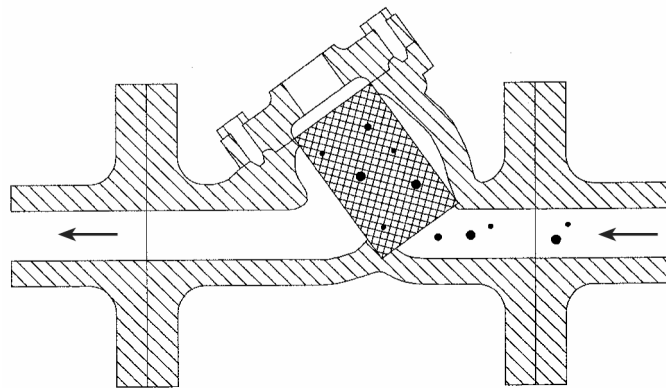


Figure 4-7
Steam Seal Strainer

4.16 Auxiliary Steam Supply

The supply station draws steam from several sources. In most units, a high-pressure steam typically required during startup is drawn directly from before the turbine stop valves. During steady-state operation at low load, the cold reheat station is designed to take over the task of supplying the steam to the pressure header. This is because using steam from the HP exhaust is more economical.

Some boilers might not provide an adequate source of steam at the temperature and pressure necessary to seal the turbine in the gland area. Therefore, if the power plant design requires it, there might also be a third supply station, as shown schematically in Figure 3-10. In these instances, it is necessary to provide an auxiliary source of sealing steam. Auxiliary steam can come from another unit boiler or an auxiliary boiler. In BWR cycles, a steam seal evaporator is typically used to supply steam to the steam seal system in order to reduce the radiation and to limit the chance of radioactive steam being released to the environment. Steam seal evaporators are described in Section 4.8.

Steam conditions from the auxiliary steam supply must be similar to those provided by the normal steam source. Excessive temperature differential between the sealing steam and the turbine rotor could cause high thermal stresses on the surface of the turbine shaft in the gland area. Repeated excessive thermal cycling could cause thermal fatigue and/or rotor distortion. In addition, the sealing steam at excessive temperature can also cause excessive differential expansion between the turbine shaft and the stationary components.

4.17 Steam Seal Instrumentation

The turbine supervisory system monitors critical steam seal system parameters. The parameters that are typically monitored include:

- Gland seal steam evaporator level
- Steam seal header supply valve position
- Steam seal header pressure and temperature
- Steam seal/gland exhaust vacuum
- Steam seal/gland exhaust blower automatic trip
- Steam seal/gland exhaust blower overload

The steam seal systems were originally designed with minimal instrumentation. When troubleshooting problems with this system, additional instrumentation is required. Pressure gauges and flow orifice plates are added to monitor the conditions of each piping section.

5

PREVENTIVE MAINTENANCE BASIS

This section establishes a PM basis for the turbine steam seal system and its components.

5.1 Background

Many power plants are in the process of reducing PM costs and improving equipment performance by matching PM tasks with the functional importance of the equipment. For this to succeed, utilities require information on the most appropriate tasks and task intervals for important equipment types, while accounting for the influences of functional importance, duty cycle, and service conditions.

An early approach to optimizing the PM activities was the use of reliability centered maintenance (RCM). RCM was developed in the 1960s by the commercial airline industry to apply reliability concepts to maintenance and the design of maintenance programs. The RCM approach to preventing equipment failure is to perform maintenance tasks that are specifically aimed at preventing component failure mechanisms from occurring. Many nuclear power plants used the RCM process to improve their PM programs.

In 1991, the Nuclear Regulatory Commission issued 10CRF50.65, *Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants*, also called the *Maintenance Rule*. In brief, the Maintenance Rule required the nuclear power plants to develop a reliability and availability monitoring program for the systems, structures, and components considered to be within the scope of the rule. The monitoring part of the rule included determining the effectiveness of the maintenance performed on the components. In addition, the Maintenance Rule required the utility to evaluate industry-operating experience and to use that experience when modifying the maintenance program. When maintenance practices have been changed, the most common action is to modify the PM tasks for the components.

When selecting time intervals for PM activities, particularly when the task is labor intensive or intrusive, consideration should be given to the fact that shorter intervals are costly, require additional resources, and potentially provide more opportunities for errors. Reliability data suggests that too frequent complex, intrusive, or labor-intensive inspections may increase the failure rate and unavailability.

Initially, the frequency of PM tasks was based on vendor recommendations and plant experience. In modifying or optimizing the preventive maintenance tasks, one vital piece of information was missing—the time to failure for the components. Because the time to failure was not known, it was difficult to justify the PM task intervals. Also missing was the understanding of the factors that influence the progression of the degradation mechanisms for the component.

As a result of the need to comply with the Maintenance Rule for nuclear power plants and to optimize the PM tasks for more effective maintenance, the PM basis project was proposed by EPRI. The PM basis objective was to:

- Provide a summary of industry experience on which the PM tasks and task intervals were based
- Establish the relationship between the degradation mechanism, the progression of the mechanisms to failure, and the opportunities available to discover the failure mechanisms before component failure occurred

During the 1996–1998 timeframe, 39 PM basis documents were developed for major components in nuclear power plants. The components included various style valves, switchgear, motor control centers, motors, pumps, compressors, HVAC (heating, ventilation, and air conditioning) components, inverters, batteries, relays, heat exchangers, turbines, transformers, and instrumentation and control (I&C) components. The PM basis documents can be found in *Preventive Maintenance Basis, Volumes 1–38* [1].

Currently, there are more than 73 component types in an electronic PM database. The database can be accessed by logging onto www.epri.com and searching for *Preventive Maintenance Database Version 5.1.1* [2]. The product can be downloaded from www.epri.com; however, it is best to order the CD from the EPRI Customer Assistance Center at 800.313.3774.

Although fossil power plants do not have the same regulatory requirements as nuclear power plants, the establishment of the PM basis for critical components provides valuable information for the optimization of the maintenance program.

The next step in the development of this PM basis document is an additional review with plant personnel. The PM tasks are further analyzed for criticality, condition monitoring options, and other parameters before being added to the EPRI PM database.

Information used in the development of the PM basis was gathered from the manufacturers, industry literature, and input from utility personnel. The following is a description of the tables generated by the PM basis document.

5.2 Failure Locations, Degradation Mechanisms, and Preventive Maintenance Strategies

The deposition of information for the steam seal system components is contained in the following tables. This series of tables lists the failure mode analysis of key steam seal system equipment and contains the following elements:

- **Failure locations** – A list of the most common components
- **Degradation mechanisms** – The cause of the component failing at the specified failure location
- **Degradation influence** – Aspects of the environment, plant operations, maintenance, or design that cause the initiation of degradation processes or can affect how rapidly the degradation progresses
- **Degradation progression** – Whether the degradation progress is present most of the time (continuous) or whether it would not normally be present but might exist or initiate in a haphazard (random) way
- **Failure timing** – The relevant time period that the component would be free from failure
- **Discovery opportunity** – Reasonable, cost-effective opportunities for detecting the failure mechanism
- **PM strategy** – The choice of PM tasks that can discover the failure mechanism

5.3 Preventive Maintenance Tasks and Their Degradation Mechanisms

Tables 5-1 and 5-2 identify PM tasks that should mitigate the failure of steam seal system components. The input for these tables was obtained from the *EPRI Preventive Maintenance Basis Guidelines* [3], vendor recommendations, plant input, and/or engineering experience and judgment.

5.4 Preventive Maintenance Strategy Definitions

The following is a brief description and explanation of the five PM tasks/strategies included in Tables 5-1, 5-2, and 5-3:

- **Vibration analysis** – Monitoring the rotating components of the steam seal system with vibration sensors and performing vibration data analysis can identify degraded equipment prior to failure.
- **Visual inspection** – Possibly the single most important and effective PM task or strategy is the visual inspection. Visual inspection includes not only what an individual sees but also what is heard. Changes in sounds or overall appearance can be precursors to equipment degradation or failure. Visual inspections include operator rounds where the equipment is observed, sounds are listened to, and general observation of the surrounding area is made.

Operators performing operator rounds, system engineers observing system operation, and management personnel typically make visual inspections.

- **Surveillance** – Surveillances are preplanned PM activities and are typically performed every three to five years. This three-to-five-year timeframe can vary significantly based on the size and age of the turbine systems and whether the unit is nuclear or fossil-fired. Surveillance activities include the following:
 - Valve diagnostics
 - Valve stroke time testing
 - Leak testing
 - NDE testing
 - Heat exchanger cleaning and Δ -temperature testing
- **Scheduled calibration** – Scheduled calibrations include the preplanned verification and adjustments to ensure accuracy of the instruments or components that provide operators or engineers analytical and performance information about the operation of a system or component. In addition to providing information, the instruments or components can initiate actions such as turbine trips, system isolations, or equipment starts. It is essential that the information or action derived from the instrument or component is accurate. Scheduled calibrations ensure that the information is accurate.
- **Scheduled inspection/overhaul** – Any equipment or component that is necessary for the continued safe operation of the steam seal system should be inspected and overhauled on a regular preplanned basis. The scheduled inspection/overhaul includes the necessary repairs or adjustments necessary to bring the equipment or component back into compliance with the original design specification. A successful scheduled inspection/overhaul will ensure that the equipment or component will perform its intended function and will not fail before the next scheduled inspection/overhaul.

The following is a summary of the PM basis tables:

Table 5-1 Steam Seal System PM Basis

Table 5-2 Steam Seal System Failure Locations, Degradation Mechanisms, and PM Strategies

Table 5-3 PM Template for the Turbine Steam Seal System

Table 5-1
Steam Seal System PM Basis

Failure Location	Location/ Degradation Mechanism	Degradation Influence	Degradation Progression	Time to Failure	Discovery Opportunity	PM Strategy
Air-operated control valves Air-operated diverting/spillover valve	Elastomer failure	Age, temperature, lack of lubrication, compression set, chemicals/air contamination Improper installation	Continuous/random	Years/random	Testing	Surveillance
	Bushing/cylinder wear	Misalignment	Random	Random	Testing	Surveillance
	Improper installation of the diaphragm	Diaphragm plate alignment, surface finish, torque	Random	Random, could be immediate	Testing	Surveillance
	Spring relaxation	Initial preload	Continuous	Random	Testing	Surveillance
	Loose coupling	Damaged threads	Random	Random	Visual inspection, testing	Visual inspection, surveillance
	Binding between antirotation plate and coupling block	Manufacturing defect	Random	Random	Testing	Surveillance
	Worn yoke	Lack of lubrication	Continuous	Expect to be failure- free for five years; could be longer for low duty cycle	Visual inspection	Visual inspection
		Duty cycle	Continuous	Expect to be failure- free for five years; could be longer for low duty cycle	Testing	Surveillance

Table 5-1 (continued)
Steam Seal System PM Basis

Failure Location	Location/ Degradation Mechanism	Degradation Influence	Degradation Progression	Time to Failure	Discovery Opportunity	PM Strategy
Air-operated control valves (cont.)	Gear wear	End stop adjustment	Random	Random	Testing	Surveillance
	Cracked valve body seat, including moving part	Design	Random	Random	Overhaul	Scheduled inspection/ overhaul
Air-operated diverting/spillover valve (cont.)	Wear/erosion, including soft or hard seating materials	Inadequate seat load	Continuous	Random	Testing	Surveillance
	Wear in valve body seat, including moving part	System dynamics/ flow induced vibration	Continuous	Expect to be failure- free 5–10 years under mild conditions	Testing Overhaul	Surveillance Scheduled inspection/ overhaul
	Bent valve body bearing/bushing	Over thrust	Random	Random	Overhaul	Scheduled inspection/ overhaul
	Excessive friction in packing or worn packing	Improper torque of the gland	Random	Random	Testing	Surveillance
	Positioner drift	Age	Continuous	Expect to be failure- free 5–10 years	Testing	Surveillance

Table 5-1 (continued)
Steam Seal System PM Basis

Failure Location	Location/ Degradation Mechanism	Degradation Influence	Degradation Progression	Time to Failure	Discovery Opportunity	PM Strategy
Motor-operated shutoff valve	Pinched wires Cracked terminal blocks Loose wires Poor crimps Cracked/damaged insulation	Personnel error	Random	Random	Visual inspection, insulation testing	Visual inspection, surveillance
	Lubrication failure	Aging	Continuous	Random	Testing	Surveillance
	Shorted windings	Aging Temperature Radiation	Continuous	Random	Diagnostic test	Surveillance
	Magnesium rotor bar corrosion	Duty cycle Moisture	Random	Random	Overhaul	Scheduled inspection/ overhaul
	Misalignment of worm to worm gear	Design Localized heating	Random and highly condition dependent	Random	Testing	Surveillance
	Stem nut locknut failure	Key material Personnel error	Random	Random	Testing	Surveillance
	Incorrect preloading of the thrust bearing	Personnel error	Random	Random	Testing	Surveillance

Table 5-1 (continued)
Steam Seal System PM Basis

Failure Location	Location/ Degradation Mechanism	Degradation Influence	Degradation Progression	Time to Failure	Discovery Opportunity	PM Strategy
Motor-operated shutoff valve (cont.)	Damage to clutch mechanism	Personnel error	Random	Random	Diagnostic test	Surveillance
	Drive sleeve/gear case seal failure	Wear Personnel error – excessive force	Continuous Random	10 years good service on high manual use valves Random	Diagnostic test	Surveillance
	Spring pack hydraulic lock	Excessive torque, predominately on wedge-type gate valves Design – valve/actuator time loading characteristics Hammering during diagnostic testing	Random	Random	Diagnostic test	Surveillance
	Spring pack spring relaxation	Design	Random	Random	Diagnostic test	Surveillance
	Seat distortion	Personnel error Procedural error	Random	Random	Diagnostic test	Surveillance
	Seat crud buildup	System conditions	Continuous	Continuous	Diagnostic test	Surveillance
	Valve stem bent	Excessive force	Continuous	Random	Overhaul	Scheduled overhaul
	Stem/stem nut thread damage	Over-tightened improper setup or testing	Random	Random	Diagnostic test	Surveillance

Table 5-1 (continued)
Steam Seal System PM Basis

Failure Location	Location/ Degradation Mechanism	Degradation Influence	Degradation Progression	Time to Failure	Discovery Opportunity	PM Strategy
Motor-operated shutoff valve (cont.)	Packing leakage	Corrosion Debris Machining tolerances Alignment	Random	Random	Visual inspection	Visual inspection
	Worn guides	Aging Gouged stem Incorrect torque	Continuous Random	Expect guide failure in ~3 years for high duty cycle valves and >10 years for low duty valves	Diagnostic test	Surveillance
Gland seal assemblies	Worn seals	Rubbing between shaft and seal	Random	Random	Overhaul	Scheduled overhaul
	Worn brushes	Aging	Continuous	Continuous	Overhaul	Scheduled overhaul
	Spring relaxation	Aging	Continuous	Continuous	Overhaul	Scheduled overhaul
	Erosion	System conditions dependent on: • Fluid condition • High fluid velocity • Valve location in reference to bends, transitions, and so on	Continuous	Continuous	Overhaul	Scheduled overhaul
	Corrosion	Fluid conditions	Continuous after initiation but random in start time	Random	Visual inspection, overhaul	Visual inspection Scheduled overhaul

Table 5-1 (continued)
Steam Seal System PM Basis

Failure Location	Location/ Degradation Mechanism	Degradation Influence	Degradation Progression	Time to Failure	Discovery Opportunity	PM Strategy
Steam seal headers/piping	Erosion	System conditions dependent on: • Fluid condition • High fluid velocity • Valve location in reference to bends, transitions, and so on	Continuous	Can expect at least 20 years before failure, but the combination of fluid condition, velocity, and valve location may reduce this value	Testing	Surveillance
	Corrosion	Fluid conditions	Continuous after initiation but random in start time	Random	Visual inspection Overhaul	Visual inspection Scheduled overhaul
Swing check valve	Broken spring	Chemical attack Aging due to creep Fatigue	Random	Random	Overhaul	Scheduled overhaul
	Leaking past disk	Corrosion Debris	Continuous	Random, on a scale of many years	Visual inspection Testing	Visual inspection Surveillance
	Leakage – cover gasket or hinge pin cover	Aging Improper installation	Continuous Random	Random	Visual inspection	Visual inspection

Table 5-1 (continued)
Steam Seal System PM Basis

Failure Location	Location/ Degradation Mechanism	Degradation Influence	Degradation Progression	Time to Failure	Discovery Opportunity	PM Strategy
Swing check valve (cont.)	Erosion	System conditions dependent on: • Fluid condition • High fluid velocity • Valve location in reference to bends, transitions, and so on	Continuous	Can expect at least 20 years before failure, but the combination of fluid condition, velocity, and valve location may reduce this value	Overhaul	Scheduled overhaul
	Corrosion	Fluid conditions	Continuous after initiation but random in start time	Random	Visual inspection Overhaul	Visual inspection Scheduled overhaul
	Disk detachment	Vibration or oscillation Corrosion	Continuous	Random	Overhaul	Scheduled overhaul
	Binding	Corrosion Debris/crud buildup	Continuous Random	Random	Visual inspection Overhaul	Visual inspection Scheduled overhaul
	Distortion Cracked seats	Impact loading	Random	Random	Overhaul	Scheduled overhaul
	Crud buildup	Fluid quality	Continuous	Random	Overhaul	Scheduled overhaul
	Chipped seat(s)	Debris	Random	Random	Overhaul	Scheduled overhaul

Table 5-1 (continued)
Steam Seal System PM Basis

Failure Location	Location/ Degradation Mechanism	Degradation Influence	Degradation Progression	Time to Failure	Discovery Opportunity	PM Strategy
Manual shutoff valves	Cracked valve body seat, including moving part	Design	Random	Random	Overhaul	Scheduled overhaul
	Wear/erosion, including soft or hard seating materials	Inadequate seat load	Continuous	Random	Overhaul	Scheduled overhaul
	Wear in valve body seat, including moving part	System dynamics/ flow-induced vibration	Continuous	Expect to be failure- free for 5–10 years under mild conditions	Overhaul	Scheduled overhaul
	Bent valve body bearing/bushing	Over thrust	Random	Random	Visual inspection Overhaul	Visual inspection Scheduled overhaul
	Excessive friction in packing or worn packing	Improper torque of the gland	Random	Random	Testing	Surveillance
Steam seal evaporator	Evaporator tubes erosion (internal)	High flow velocity Suspended solid Foreign material Flow-accelerated corrosion Nonuniform scale deposits	Continuous Random	Random on a scale of months to many years	Testing	Surveillance
Steam seal condenser	Evaporator tubes erosion (external)	Fluid impingement Foreign material	Continuous Random	Random, could be very rapid	Testing	Surveillance

Table 5-1 (continued)
Steam Seal System PM Basis

Failure Location	Location/ Degradation Mechanism	Degradation Influence	Degradation Progression	Time to Failure	Discovery Opportunity	PM Strategy
Steam seal evaporator (cont.) Steam seal condenser (cont.)	Evaporator tubes corrosion	Fluid quality Internal tube surface condition Water temperature range 60°–90°F+ Water chemistry Low flow rates (including inlet valve leakage during lay-up) Tube material Improperly designed or operated cathodic protection Tube manufacture (for example, discontinuities and welds)	Continuous Random	Random, can be rapid	Overhaul	Scheduled inspection/ overhaul

Table 5-1 (continued)
Steam Seal System PM Basis

Failure Location	Location/ Degradation Mechanism	Degradation Influence	Degradation Progression	Time to Failure	Discovery Opportunity	PM Strategy
Steam seal evaporator/steam seal condenser (cont.)	Evaporator tube defects	Manufacturing defect Installation error	Random	Random	Testing Overhaul	Surveillance Scheduled inspection/ overhaul
	Evaporator tube cracking	Vibration Fatigue	Continuous Random	Random	Testing Overhaul	Surveillance Scheduled inspection/ overhaul
	Internal hardware deterioration, including on baffle plates, support plates, tie rods, spacers, diffuser plates, impingement plates, and loose or failed welds	Water hammer Vibration Thermal stress Impingement	Random	Random	Overhaul	Scheduled inspection/ overhaul
	Tubesheet Corrosion Cracking of ligaments	Improper cathodic protection Water chemistry Materials	Random	Random	Overhaul	Scheduled inspection/ overhaul
	Gaskets and O-rings on closure devices deterioration	Improper installation Aging Improper material	Random Continuous	Random	Visual inspection	Visual inspection

Table 5-1 (continued)
Steam Seal System PM Basis

Failure Location	Location/ Degradation Mechanism	Degradation Influence	Degradation Progression	Time to Failure	Discovery Opportunity	PM Strategy
Steam seal exhauster	Fan and motor dirt buildup	Debris, foreign material, and airborne debris	Random Continuous	Random Continuous	Visual inspection Vibration	Visual inspection Vibration analysis
	Cracking blades	Aging Debris, foreign material, and airborne debris	Random Continuous	Continuous Random	Testing	Surveillance
	Pinched wires Cracked terminal blocks Loose wires Poor crimps Cracked/damaged insulation	Personnel error	Random	Random	Visual inspection Insulation testing	Visual inspection Surveillance
	Lubrication failure	Aging	Continuous	Expect 15 year trouble-free period	Testing	Surveillance
	Shorted windings	Aging Temperature Radiation	Continuous	For mild conditions expect >20 years and for severe conditions expect 8 years of good service	Testing	Surveillance

Table 5-1 (continued)
Steam Seal System PM Basis

Failure Location	Location/ Degradation Mechanism	Degradation Influence	Degradation Progression	Time to Failure	Discovery Opportunity	PM Strategy
Blowdown valves	Gaskets and O-rings on closure devices deterioration	Improper installation Aging Improper material	Random Continuous	Random	Visual inspection	Visual inspection
	Broken springs	Chemical attack Aging due to creep Fatigue	Random	Random	Visual inspection	Visual inspection
	Erosion	System conditions dependent on fluid condition, high fluid velocity, valve location in reference to bends, transitions, and so on	Continuous	Can expect at least 20 years before failure, but the combination of fluid condition, velocity, and valve location may reduce this value	Testing	Surveillance
	Corrosion	Fluid conditions	Continuous after initiation but random in start time	Random	Overhaul	Scheduled inspection/ overhaul
	Disk detachment	Vibration or oscillation	Continuous	Random	Overhaul	Scheduled inspection/ overhaul
	Solenoid valve malfunction	Aging	Random	Random	Diagnostics	Surveillance

Table 5-1 (continued)
Steam Seal System PM Basis

Failure Location	Location/ Degradation Mechanism	Degradation Influence	Degradation Progression	Time to Failure	Discovery Opportunity	PM Strategy
Desuperheater	Erosion	System conditions dependent on: • Fluid condition • High fluid velocity • Valve location in reference to bends, transitions, and so on	Continuous	Can expect at least 20 years before failure, but the combination of fluid condition, velocity, and valve location may reduce this value	Overhaul	Scheduled inspection/overhaul
	Corrosion	Fluid quality	Continuous	Random	Overhaul	Scheduled inspection/overhaul
Relief valves	Seat crud buildup	Fluid quality	Continuous	Random	Diagnostics	Surveillance
	Relief spring coefficient	Aging	Continuous	Expect to be failure-free for 5–10 years	Diagnostics	Surveillance
Safety head assembly	Material deterioration	Aging	Continuous	Expect to be failure-free for 5–10 years	Visual inspection	Visual inspection
	Corrosion	Fluid quality	Continuous	Random	Overhaul	Scheduled inspection/overhaul
	Erosion	System conditions dependent on: • Fluid condition • High fluid velocity • Valve location in reference to bends, transitions, and so on	Continuous	Can expect at least 20 years before failure, but the combination of fluid condition, velocity, and valve location may reduce this value	Testing	Surveillance

Table 5-1 (continued)
Steam Seal System PM Basis

Failure Location	Location/ Degradation Mechanism	Degradation Influence	Degradation Progression	Time to Failure	Discovery Opportunity	PM Strategy
Steam seal strainers	Material deterioration	Aging	Continuous	Expect to be failure-free for 5–10 years	Visual inspection	Visual inspection
	Corrosion	Fluid quality	Continuous	Random	Overhaul	Scheduled inspection/overhaul
	Erosion	System conditions dependent on: • Fluid condition • High fluid velocity • Valve location in reference to bends, transitions, and so on	Continuous	Can expect at least 20 years before failure, but the combination of fluid condition, velocity, and valve location may reduce this value	Visual inspection	Visual inspection
	Plugging	High flow velocity Suspended solid Foreign material Flow-accelerated corrosion Nonuniform scale deposits	Continuous Random	Continuous Random	Visual inspection	Visual inspection
Steam seal instrumentation	Setpoint drift	Aging	Continuous	Continuous	Calibration	Scheduled calibration

Table 5-2
Steam Seal System Failure Locations, Degradation Mechanisms, and PM Strategies

Failure Location	Location/Degradation Mechanism	PM Task/Strategy and Interval				
		Vibration Analysis	Visual Inspection	Surveillance	Scheduled Calibration	Scheduled Inspection/Overhaul
Air-operated control valves	Elastomer failure	N/A	N/A	5 years	N/A	N/A
	Bushing/cylinder wear	N/A	N/A	5 years	N/A	N/A
Air-operated diverting/spillover valve	Improper installation of the diaphragm	N/A	N/A	5 years	N/A	N/A
	Spring relaxation	N/A	N/A	5 years	N/A	N/A
	Loose coupling	N/A	Daily to monthly	5 years	N/A	
	Binding between antirotation plate and coupling block	N/A	N/A	5 years	N/A	N/A
	Worn yoke	N/A	Daily to monthly	5 years	N/A	N/A
	Gear wear	N/A	N/A	5 years	N/A	N/A
	Cracked valve body seat, including moving part	N/A	Daily to monthly	N/A	N/A	5 years
	Wear/erosion, including soft or hard seating materials	N/A	N/A	5 years	N/A	N/A
	Wear in valve body seat, including moving part	N/A	N/A	3–5 years	N/A	5 years
	Bent valve body bearing/bushing	N/A	N/A	N/A	N/A	5 years
	Excessive friction in packing or worn packing	N/A	N/A	5 years	N/A	N/A
	Positioner drift	N/A	N/A	3–5 years	N/A	N/A

Table 5-2 (continued)
Steam Seal System Failure Locations, Degradation Mechanisms, and PM Strategies

Failure Location	Location/Degradation Mechanism	PM Task/Strategy and Interval				
		Vibration Analysis	Visual Inspection	Surveillance	Scheduled Calibration	Scheduled Inspection/Overhaul
Motor-operated shutoff valve	Pinched wires, cracked terminal blocks, loose wires, poor crimps, or cracked/damaged insulation	N/A	Daily to monthly	N/A	N/A	5 years
	Lubrication failure	N/A	N/A	5 years	N/A	N/A
	Shorted windings	N/A	N/A	5 years	N/A	N/A
	Magnesium rotor bar corrosion	N/A	N/A	N/A	N/A	5 years
	Misalignment of worm to worm gear	N/A	N/A	5 years	N/A	N/A
	Stem nut locknut failure	N/A	N/A	5 years	N/A	N/A
	Incorrect preloading of the thrust bearing	N/A	N/A	5 years	N/A	N/A
	Damage to clutch mechanism	N/A	N/A	5 years	N/A	N/A
	Drive sleeve/gear case seal failure	N/A	N/A	5 years	N/A	N/A
	Spring pack hydraulic lock	N/A	N/A	5 years	N/A	N/A
	Spring pack spring relaxation	N/A	N/A	5 years	N/A	N/A
	Seat distortion	N/A	N/A	5 years	N/A	N/A
	Seat crud buildup	N/A	N/A	5 years	N/A	N/A
	Valve stem bent	N/A	N/A	N/A	N/A	5 years
	Stem/stem nut thread damage	N/A	N/A	5 years	N/A	N/A
	Packing leakage	N/A	Daily to monthly	N/A	N/A	N/A
	Worn guides	N/A	N/A	5 years	N/A	N/A

Table 5-2 (continued)
Steam Seal System Failure Locations, Degradation Mechanisms, and PM Strategies

Failure Location	Location/Degradation Mechanism	PM Task/Strategy and Interval				
		Vibration Analysis	Visual Inspection	Surveillance	Scheduled Calibration	Scheduled Inspection/Overhaul
Gland seal assemblies	Worn seals	N/A	N/A	N/A	N/A	5 years
	Worn brushes	N/A	N/A	N/A	N/A	5 years
	Spring relaxation	N/A	N/A	N/A	N/A	5 years
	Erosion	N/A	N/A	N/A	N/A	5 years
	Corrosion	N/A	Daily to monthly	N/A	N/A	5 years
Steam seal headers/piping	Erosion	N/A	N/A	5 years	N/A	N/A
	Corrosion	N/A	Daily to monthly	N/A	N/A	5 years
Swing check valve	Broken spring	N/A	N/A	N/A	N/A	3 years
	Leaking past disk	N/A	N/A	N/A	N/A	3 years
	Leakage: cover gasket or hinge pin cover	N/A	Daily to monthly	N/A	N/A	N/A
	Erosion	N/A	N/A	N/A	N/A	5 years
	Corrosion	N/A	Daily to monthly	N/A	N/A	5 years
	Disk detachment	N/A	N/A	N/A	N/A	3 years
	Binding	N/A	Daily to monthly	N/A	N/A	3 years
	Distortion	N/A	N/A	N/A	N/A	3 years
	Cracked seats	N/A	N/A	N/A	N/A	3 years
	Crud buildup	N/A	N/A	N/A	N/A	3 years
	Chipped seat(s)	N/A	N/A	N/A	N/A	3 years

Table 5-2 (continued)
Steam Seal System Failure Locations, Degradation Mechanisms, and PM Strategies

Failure Location	Location/Degradation Mechanism	PM Task/Strategy and Interval				
		Vibration Analysis	Visual Inspection	Surveillance	Scheduled Calibration	Scheduled Inspection/Overhaul
Manual shutoff valves	Cracked valve body seat, including moving part	N/A	N/A	N/A	N/A	5 years
	Wear/erosion, including soft or hard seating materials	N/A	N/A	N/A	N/A	5 years
	Wear in valve body seat, including moving part	N/A	N/A	N/A	N/A	5 years
	Bent valve body bearing/bushing	N/A	Daily to monthly	N/A	N/A	5 years
	Excessive friction in packing or worn packing	N/A	Daily to monthly	N/A	N/A	N/A
Steam seal evaporator	Evaporator tube erosion (internal)	N/A	N/A	3 years	N/A	N/A
Steam seal condenser	Evaporator tube erosion (external)	N/A	N/A	3 years	N/A	N/A
	Evaporator tube corrosion	N/A	N/A	3 years	N/A	N/A
	Evaporator tube defects	N/A	N/A	3–5 years	N/A	5 years
	Evaporator tube cracking	N/A	N/A	N/A	N/A	3 years
	Internal hardware deterioration, including on baffle plates, support plates, tie rods, spacers, diffuser plates, impingement plates, and loose or failed welds	N/A	N/A	N/A	N/A	3 years
	Tubesheet, corrosion cracking of ligaments	N/A	N/A	N/A	N/A	3 years
	Gaskets and O-rings on closure devices deterioration	N/A	Daily to monthly	N/A	N/A	N/A

Table 5-2 (continued)
Steam Seal System Failure Locations, Degradation Mechanisms, and PM Strategies

Failure Location	Location/Degradation Mechanism	PM Task / Strategy and Interval				
		Vibration Analysis	Visual Inspection	Surveillance	Scheduled Calibration	Scheduled Inspection/ Overhaul
Steam seal exhauster	Fan and motor dirt buildup	Six months	Daily to monthly	N/A	N/A	N/A
	Cracking blades	N/A	N/A	3 years	N/A	N/A
	Pinched wires, cracked terminal blocks, loose wires, poor crimps, or cracked/ damaged insulation	N/A	Daily to monthly	3 years	N/A	N/A
	Lubrication failure	N/A	Daily to monthly	3 years	N/A	N/A
	Shorted windings	N/A	Daily to monthly	3 years	N/A	N/A
Blowdown valves	Gaskets and O-rings on closure devices deterioration	N/A	Daily to monthly	N/A	N/A	N/A
	Broken springs	N/A	Daily to monthly	N/A	N/A	N/A
	Erosion	N/A	N/A	N/A	N/A	3 years
	Corrosion	N/A	Daily to monthly	N/A	N/A	N/A
	Disk detachment	N/A	N/A	N/A	N/A	3 years
	Solenoid valve malfunction	N/A	N/A	3 years	N/A	N/A

Table 5-2 (continued)
Steam Seal System Failure Locations, Degradation Mechanisms, and PM Strategies

Failure Location	Location/Degradation Mechanism	PM Task/Strategy and Interval				
		Vibration Analysis	Visual Inspection	Surveillance	Scheduled Calibration	Scheduled Inspection/Overhaul
Desuperheater	Erosion	N/A	N/A	N/A	N/A	3 years
	Corrosion	N/A	N/A	N/A	N/A	3 years
Relief valves	Seat crud buildup	N/A	N/A	3–5 years	N/A	N/A
	Relief spring coefficient	N/A	N/A	3–5 years	N/A	N/A
Safety head assembly	Material deterioration	N/A	Daily to monthly	N/A	N/A	N/A
	Corrosion	N/A	Daily to monthly	N/A	N/A	N/A
	Erosion	N/A	N/A	N/A	1 year	3 years
Steam seal strainers	Material deterioration	N/A	Daily to monthly	N/A	N/A	3 years
	Corrosion	N/A	Daily to monthly	N/A	N/A	N/A
	Erosion	N/A	Daily to monthly	N/A	N/A	N/A
	Plugging	N/A	Daily to monthly	N/A	N/A	3 years
Steam seal instrumentation	Setpoint drift	N/A	N/A	N/A	1 year	N/A

5.5 Preventive Maintenance Template

The PM template summarizes the program of PM strategies and intervals for the steam seal system equipment type. Each plant should base its program on the manufacturer recommendations and its own history of equipment performance. The PM template can serve as a beginning for the development of a PM program for the equipment with changes added from feedback as the program is implemented.

Columns labeled 1–8 in the PM template list the eight sets of conditions for the turbine steam seal system. Each column corresponds to the combined choices of critical or noncritical equipment, high or low duty cycle, and severe or mild service conditions. Time intervals for the performance of each strategy are entered at the intersections of the task rows and columns 1–8.

The definitions of template application conditions are:

- **Critical**

Yes – Functionally important (that is, risk significant, required for power production, safety related, or other regulatory requirement).

No – Not functionally important but economically important (for any of the following reasons: high frequency of resulting corrective maintenance, more expensive to replace or repair than to perform PM, or has a high potential to cause the failure of other critical or economically important equipment).

- **Duty Cycle**

High – Frequently cycled or partially loaded the greater part of its operation time.

Low – Fully loaded during the greater part of its operation time.

- **Service Condition**

Severe – High or excessive humidity, excessive temperatures (high/low) or temperature variations, excessive environmental conditions (that is, salt, corrosive, spray, steam, low quality suction air), or high vibration.

Mild – Clean area (not necessarily air-conditioned), temperatures within OEM specifications, or normal environmental conditions.

PM tasks – The PM tasks provide a cost-effective way to intercept the causes and mechanisms that lead to degradation and failure. The PM tasks can be used to develop a complete PM program or to improve an existing program. These tasks are intended to complement and not to replace the PM recommendations given by the manufacturer. A brief description of the PM tasks follows the PM template.

Table 5-3
PM Template for the Turbine Steam Seal System

Conditions	1	2	3	4	5	6	7	8
Critical: Yes *No	X	X	X	X				
					X	X	X	X
Duty cycle: High Low	X		X		X		X	
		X		X		X		X
Service condition: Severe Mild	X	X			X	X		
			X	X			X	X
PM tasks								
Vibration analysis	3 to 6 months	3 to 6 months	3 to 6 months	3 to 6 months	6 to 12 months	6 to 12 months	6 to 12 months	6 to 12 months
Visual inspection	Daily to monthly	Daily to monthly	Daily to monthly	Daily to monthly	Daily to monthly	Daily to monthly	Daily to monthly	Daily to monthly
Surveillance	3 to 5 years	3 to 5 years	3 to 5 years	3 to 5 years	As required	As required	As required	As required
Scheduled calibration	6 to 12 months	6 to 12 months	6 to 12 months	6 to 12 months	6 to 12 months	6 to 12 months	6 to 12 months	6 to 12 months
Scheduled inspection/overhaul	3 to 5 years	3 to 5 years	3 to 5 years	3 to 5 years	5 to 8 years	5 to 8 years	5 to 8 years	5 to 8 years

* The template does not apply to the run-to-failure components; *noncritical* here means not critical but important enough to require some PM tasks.

6

PREVENTIVE/PREDICTIVE MAINTENANCE AND CONDITION MONITORING

6.1 Background

EPRI has published a number of reports outlining an effective PM, CM, and PdM program. Table 6-1 lists these EPRI reports.

Table 6-1
EPRI Reports Related to Effective PM, PdM, or CM Programs

Report Title	Product Number	Year of Publication
Advanced Technology Training System (ATTS) for Motor-Operated Valve Training and ATTS Authoring System: Joint EPRI-CRIEPI Human Factors Studies	TR-104746	1995
Air-Operated Valve Maintenance Guide	NP-7412-R1	1996
Consolidated Plant Maintenance Optimization Guideline: For Fossil Power Plants	1004377	2003
EPRI Preventive Maintenance Basis Database, Version 3.01	1001448	2001
EPRI MOV Performance Prediction Methodology (PPM): Summary of Nuclear Power Plant MOV Evaluations	TR-111383	1998
EPRI MOV Performance Prediction Program: Performance Prediction Methodology (PPM) Version 3.0: User Manual and Implementation Guide	1006206	2001
EPRI MOV Performance Prediction Program: Performance Prediction Methodology Assessment Report	TR-103231	1994
EPRI MOV Performance Prediction Program: Performance Prediction Methodology Implementation Guide – Revision 2	TR-103244-R2	1998
EPRI MOV Performance Prediction Program: Topical Report – Revision 2	TR-103237-R2	1997
EPRI MOV Stem Lubricant Test Program: Frictional Performance of Exxon Nebula and MOV Long Life in a Stem Lubrication Application	1008140	2003
Equipment Condition Monitoring Templates: Addendum to the Preventive Maintenance Basis, TR-106857 (Volumes 1–38)	1000621	2000
Guide for Determining Preventive Maintenance Task Intervals	TR-103147	1994

Table 6-1 (continued)
EPRI Reports Related to Effective PM, PdM, or CM Programs

Report Title	Product Number	Year of Publication
Guide for Evaluating Air-Operated Valve Uncertainties and Actuator Setup Parameters	1006555	2001
Guidelines for Application of the EPRI Preventive Maintenance Basis	TR-112500	2000
Improving Maintenance Effectiveness Guidelines: An Evaluation of Plant Preventive and Predictive Maintenance Activities	TR-107042	1998
Performance of MOV Stem Lubricants at Elevated Temperature: Review of NCR/INEEL Test Program	1007030	2002
PMB C/S 1.5 - Preventive Maintenance Basis Database Client/Server, Version 1.5	1011923	2005
Predictive Maintenance Primer: Revision to NP-7205	1007350	2003
Predictive Maintenance Program: Development and Implementation	TR-108936	1999
Predictive Maintenance Self-Assessment Guidelines for Nuclear Power Plants	1001032	2000
Preventive Maintenance Information Repository (PMIR): Functional Specification	1000702	2000
Proceedings: EPRI Power Plant Valves Symposium 4	TR-101859	1998
Reliability and Preventive Maintenance: Balancing Risk and Reliability: For Maintenance and Reliability Professionals at Nuclear Power Plants	1002936	2002
Reliability Centered Maintenance (RCM) Technical Reference for Power Delivery	1002125	2003

6.2 Nondestructive Testing

A long-term monitoring of steam turbine components and auxiliaries requires a variety of nondestructive tests or evaluations (NDT or NDE). NDT can be used to assess the condition of various turbine components, including the steam seal system. Cracks can propagate due to high or low cycle fatigue and/or creep. Such service-induced cracks, which—if undetected—can cause a forced outage, are detectable with NDE techniques. Therefore, periodic NDE of the critical turbine components is recommended.

NDE is testing that does not destroy the test object. Although destructive testing usually provides a more reliable assessment of the affected part, its destruction is more costly. Various methods are available to inspect for conditions of different steam turbine components. An outline of some of the most common NDE techniques follows.

6.2.1 Visual Testing

Visual testing (VT) might be the most common form of NDT. It is simple, quick, and easy to apply. Therefore, once per shift, the operator round should include the steam seal system components. Similarly, periodic VT of the steam seal system by maintenance personnel is recommended.

6.2.2 Liquid Penetrant Testing

Liquid (or dye) penetrant testing (PT) serves as an extension of the visual inspection. It offers a fast, cheap, and relatively simple means of surface inspection. It can be used to detect any surface discontinuities, such as cracks, lack of fusion at welded areas, or any nonabsorbent surface imperfections. To conduct liquid PT, the affected surface must first be thoroughly cleaned. Any grease or dirt must be removed. A brightly colored or fluorescent liquid is applied to the inspected surface and allowed to penetrate any surface-breaking material flaws. It is then allowed to soak for approximately 20 minutes. Subsequently, the excess penetrant is wiped out and the developer, typically a white powder, is applied. Due to reverse capillary action, the developer draws the liquid penetrant out of any cracks. Thus, colored indications appear on the inspected surface. Because these indications are wider than actual cracks, they can be detected easily.

Penetrants delineate any surface discontinuity to a much greater extent, making the inspection less prone to human error. However, if a fluorescent penetrant is used, it must be viewed under darkness with an ultraviolet lamp. This might not always be practical. The most common agents used for liquid PT can be removed with a solvent or water. A typical kit consists of three aerosol cans: red penetrant, white developer, and a solvent.

It is important that personnel carrying out liquid PT be properly trained and qualified. This is because liquid PT can be misused if:

- Test surfaces are not cleaned adequately.
- The length of time the penetrant contacts the test surface is too short.
- The excess penetrant is removed carelessly.

6.2.3 Magnetic Particle Testing

Magnetic particle testing (MT) is another NDE technique used for crack detection. It is relatively easy and simple and can be applied to a specimen of almost any size, shape, or composition. However, the component being inspected must be made of a ferromagnetic material, such as iron, nickel, cobalt, or some of their alloys. (Ferromagnetic materials are materials that can be magnetized to a level that will allow the inspection to be effective.)

The easiest way to visualize the magnetic particle inspection method is to imagine a magnet bar that is cracked but not broken. Because of the discontinuity, two complete magnets with magnetic poles on each end of each piece will result. North and south poles will form at each edge of the crack. If iron particles are sprinkled on the cracked magnet, the particles will cluster not only at the poles at the ends of the bar, but also at the poles located at the edges of the crack. The resultant cluster of particles is much easier to see than the actual crack.

In practice, two basic steps are involved in the magnetic particle inspection—the magnetization of the material and the application of the magnetic particles. Magnetic particles can be either dry or suspended in a liquid. As mentioned, a pair of magnetic poles will be formed on both sides of a surface or a subsurface crack, as long as it is located sufficiently close to the surface. The poles will act as magnets and will therefore attract the magnetic particles. Thus, a visible indication of the defect will be formed. It should be noted, however, that surface defects generate sharp powder patterns, whereas subsurface cracks give less defined shapes. Therefore, only properly trained and qualified personnel should be performing NDE inspections.

A high skill level might be necessary to detect subsurface cracks. However, most service-induced cracks are fairly easy to detect because they originate on the surface of the inspected component. This is because cracks caused by high cycle fatigue or thermal cracking, common mechanisms of failure in a steam turbine, typically originate on the surface of the affected component.

The surface condition of the inspected object can also affect the results. The surface must be clean, dry, and free of rust. Therefore, before the inspection is conducted, wire brushing or sandblasting is recommended. This is especially important if subsurface cracks need to be detected.

6.2.4 Eddy Current Testing

Eddy current testing (ET) is one of the most common NDE methods. The equipment is very portable and is commonly used in the tube and pipe industry. Eddy current inspection can be applied to both ferrous and nonferrous materials and is simple to install and operate. This method is sensitive to small cracks and can also be used to detect near-surface defects. However, flaws that lie parallel to the probe coil winding and probe scan direction are undetectable. In addition, the surface finish can affect the results.

Eddy currents are created through a process called *electromagnetic induction*. High-frequency alternating electrical currents are induced to flow in a circular path in the inspected metallic specimen. The flow pattern can be either circumferential or tangential, depending on whether an encircling or pancake coil configuration is used. The eddy currents generate a magnetic field. Cracks or other flaws perturb the flow pattern of the eddy currents. This, in turn, affects the associated magnetic field and is detectable by electromagnetic means.

6.2.5 Ultrasonic Testing

Ultrasonic testing (UT) is based on high-frequency sound used to detect material flaws. The necessary equipment consists of a pulser, a transducer, and a display device. The pulser is a device that can produce a high-voltage electrical pulse. The transducer is driven by the pulser and generates high-frequency ultrasonic energy. The sound propagates through the tested specimen. There are several types of ultrasonic waves—longitudinal, transverse, and surface. The transmission of ultrasonic energy depends on particle vibration. For example, cast iron and other coarse-grained materials are difficult to inspect due to low sound transmission.

A crack or discontinuity will reflect the sound wave. The reflected wave signal is transformed into electrical signal by the transducer and is displayed on a screen. The ultrasonic inspection is equally effective with surface and subsurface discontinuities. The depth of penetration for flaw detection is superior to that of other NDE techniques; however, the skill level required for this NDE method is more extensive than with some other methods.

6.2.6 X-Ray Radiography

X-ray radiography (RT) is an NDE method that uses X-ray or gamma radiation to detect internal cracks, voids, porosity, and inclusions in metallic materials, as well as delamination and fracture in composites. X rays are produced when high-speed electrons strike a metal target. The intensity of the penetrating radiation is altered by passage through the material and affected by its defects. Because X rays produce photochemical effects in photographic emulsions, a photograph of the internal material can be taken.

6.3 PM Task Evaluation Process

EPRI has developed a disciplined process to identify the PM tasks for the components of the steam seal system. The PM maintenance tasks can be identified by answering the following questions:

- Is a failure-finding task needed? This is simply a matter of deciding if a failure would be evident to the operating crew in a timely way and whether it would be important if the failure were not detected. The importance of the failure should at least reach the noncritical level.
- What generic failure mechanisms should be expected?
- Which PM tasks are recommended by the vendor? The vendor manuals will recommend PM tasks and intervals. This step is intended to obtain this information for critical equipment only. Check the vendor tasks against the recommendations in the *EPRI Preventive Maintenance Basis Database, Version 3.01* [3].
- Which PM tasks are recommended by the *EPRI Preventive Maintenance Basis Database, Version 3.01* [3]?

- Do the task(s) adequately address the target failure causes?
- Are there CM tasks that are more cost effective?
- Are there time-directed tasks that are more cost effective?

6.4 Predictive Maintenance

Various PdM tools are available. However, depending on the technology and the familiarity or interest of the personnel, these can have varying degrees of success in application.

There are three monitoring categories—general, directed, and visual. These categories are organized in a top-down, tiered progression, from the less intrusive, general-parameter monitoring to the more intrusive, component-specific inspections.

6.4.1 General Monitoring

General monitoring, because it commonly provides a macroscopic overview (“big picture”) of the steam seal system, is ranked as top-level monitoring. These monitoring techniques also tend to be the least intrusive and usually do not require equipment to be removed from service. General monitoring includes VT and steam seal system parameter history and trending.

Determination of alert limits for key monitored parameters ensures a timely warning of significant deviation from baseline operation. Appropriate actions must be defined in advance in order to prevent severe damage or forced outage of the monitored equipment. A more specific approach can be developed from detailed analysis of top-level monitoring.

Figure 6-1 outlines a flow chart that can be followed to analyze potential problems with steam seal system headers.

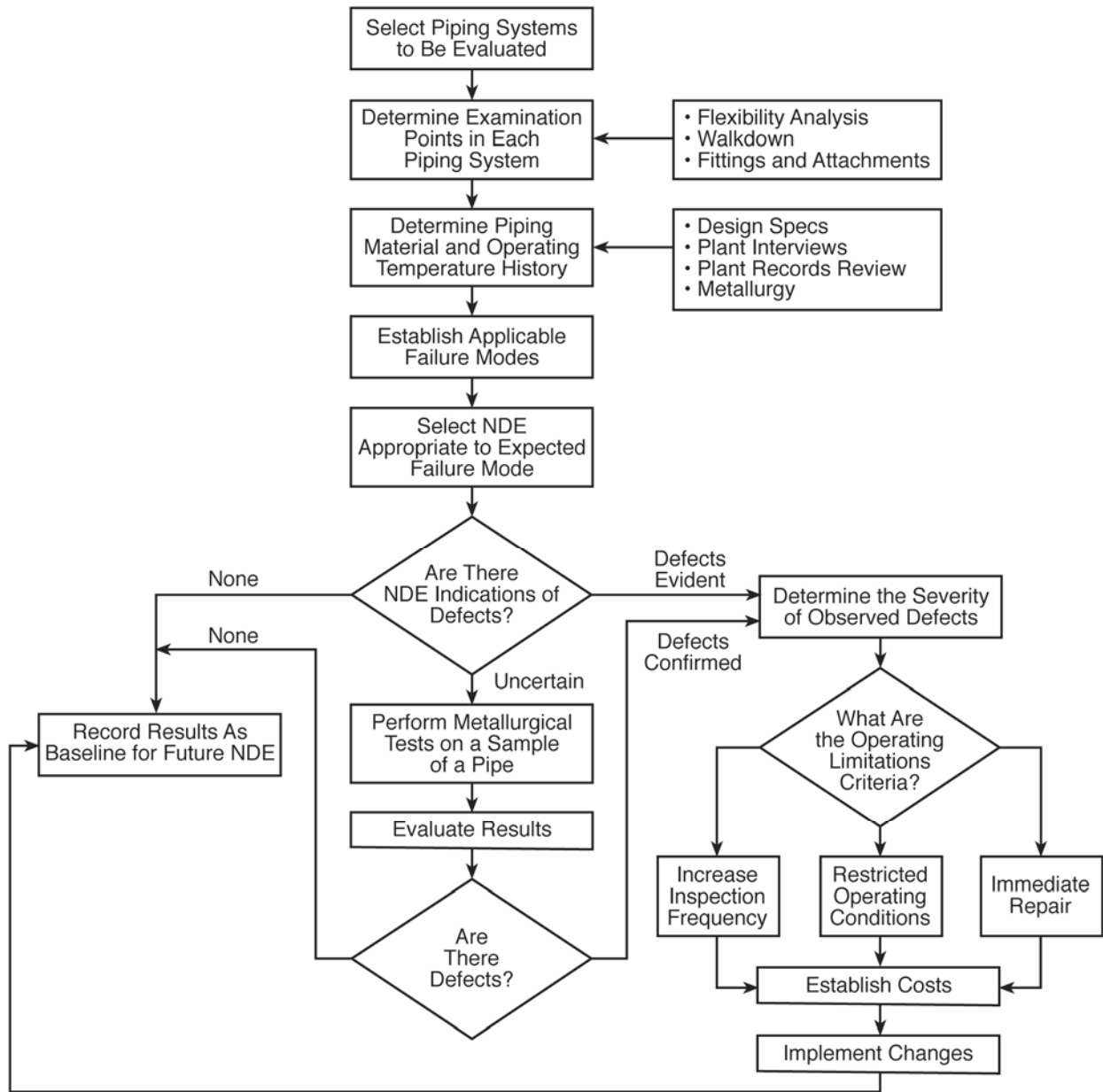


Figure 6-1
Piping Evaluation Flow Chart [1]

6.5 Condition Monitoring

Any information or recommendations regarding PM or CM in this report should be combined with the OEM's recommendations. Any changes to the OEM's recommendations should be thoroughly reviewed and documented. The information contained in this report is intended to enhance the background and history of similar equipment and provide an input into the decision-making process when deviating from the OEM's recommendations. The information contained in this report is intended to serve as additional information on the cause of specific failures. Further, this report outlines steam seal system degradation; when considered over a period of time, the information will support the decision to change the PM or CM activity or the frequency thereof. The frequency of the PM or CM activity should be established and changed by each utility based on that utility's individual plant experience and history.

Table 6-2 provides the recommended CM activities and their frequencies as applicable to a steam seal system. The sample monitoring recommendations are representative of common activities; information provided should be adjusted to fit plant-specific equipment applications based on the OEM's recommendations and specific plant experiences.

Table 6-2
Recommended Steam Seal System CM Activities

Equipment/Task	Frequency						
	Daily	Weekly	Monthly	Semiannual	Annual	Pre-Outage	Outage
General monitoring, including unusual noise and visible vibration of any of the components identified in Section 4	Yes						
Heat exchanger temperature profiles			Yes				
Heat exchanger/evaporator tubes							Yes
Instrument deficiencies	Yes						
Leaks: airborne noise detection			Every three months				
Lube oil analysis if exhausters blowers are oil lubricated			Yes				
Missing equipment tags and labels	Yes						
Missing instrument fasteners	Yes						
Missing tubing supports	Yes						
Missing valve handwheels	Yes						
Monitor oil use/consumption	Yes						
Motor current draw of the exhauster fan motors			Every three months				
Motor temperature profiles			Yes				
Oil leaks	Yes						
Pipe hangers and supports	Yes						
Routine visual	Yes						
UT of the steam seal piping, looking for minimum wall conditions due to erosion							Yes
Vibration analysis of exhauster fans and any other rotating equipment			Every six months				
Evaluation of effect of seal leakage on turbine performance					As required		

As discussed previously, without the gland seals, steam would leak out of the HP turbine through the path formed between the shaft and the stationary casing. To limit this flow, gland seal assemblies are installed at each end of the HP turbine. However, due to the phenomena outlined in Sections 5.1 and 8.1, the seal strips employed in the turbine gland areas (and in the interstage seals) degrade over the life of the unit. To perform a valid economic analysis and to consider replacement of seals, the impact of the seal degradation on heat rate should be determined.

A number of methods can be used in assessing the impact of turbine seal clearances on thermodynamic performance. The most common are empirical approaches based on test data subsequently coded into mean-line codes, which model steam expansion along the mean diameters of the airfoils and solve for steam conditions at the inlet and exit of each airfoil. These techniques either convert leakage into a loss coefficient or calculate the lost work due to leakage area. Such calculations tend to be fairly accurate as long as the calculated geometry is similar to the one originally tested. Consequently, the mean-line calculations performed by the OEM on its own equipment will be very accurate because they closely match the tested geometry and are calibrated to match the test results. However, when a non-OEM analyzes a design manufactured by a different company, the mean-line calculations will probably be somewhat less accurate. This is because of slight variations in the design features and the manufacturing techniques that affect the empirical test results. However, some of these difficulties can be overcome by calculating the change in efficiency rather than the seal leakage/loss on the absolute level.

As an alternative to the empirically based calculation techniques, computational fluid dynamics (CFD) models can be used to evaluate the effect of seal leakage on turbine performance. However, some issues must be carefully considered before the CFD analysis is undertaken. The seal clearance is on the order of 10^{-2} in. (0.01 in.), while the seal cavities are on the order of 10^{-1} in. (0.10 in.), and the overall flow path is on the order of 10^{+1} in. (10 in.). Similar order-of-magnitude issues are present in the flow characteristics, where some areas might approach sonic velocities but other areas might be stagnant. Solving this range of flow regimes with the required accuracy can be a difficult task. Therefore, most turbine manufacturers rely on mean-line codes to evaluate the effect of seal clearances on the efficiency of the steam turbine. Mean-line codes model steam expansion along the mean diameters of the airfoils and solve for steam conditions at the inlet and exit of each airfoil. These techniques either convert leakage into a loss coefficient or calculate the lost work due to leakage area. Such calculations tend to be fairly accurate as long as the calculated geometry is similar to the one originally tested. Consequently, the mean-line calculations performed by the OEM on its own equipment will be very accurate because they closely match the tested geometry and are calibrated to match the test results.

Sometimes, a combination of these approaches is undertaken. Upstream and downstream steam conditions, turbine thermodynamic characteristics, and detailed geometry of the seal are required to evaluate the effect of degraded seals on turbine performance.

Another concern for steam seal system maintenance is the potential for creep deformation and/or rupture. This is because some portions of pressure header can operate in creep regime. Creep is a complex phenomenon in which materials subjected to stress and high temperature undergo a time-dependent deformation. Deterioration begins when strain progresses to the point at which microscopic voids begin to form between the grain boundaries. These voids increase if stress and temperature remain constant. The orientation of the initial voids is usually perpendicular to the

direction of the principal stress. The voids continue to grow and link up until micro-cracks are formed; the micro-cracks, in turn, will become macro-cracks. Macro-cracks are detectable with conventional NDE methods. If the problem is not addressed, creep rupture will occur.

To minimize creep deformation, the operating temperature of the pressure header should be maintained at or below the design value. If required, an estimate of the impact of change in operating temperature on the remaining creep life can be obtained from a figure from ASME B31.1a-2005 [4], reproduced below as Figure 6-2. (A more accurate estimate for time to rupture for a given material under constant stress and temperature can be calculated from the Larson-Miller parameter.)

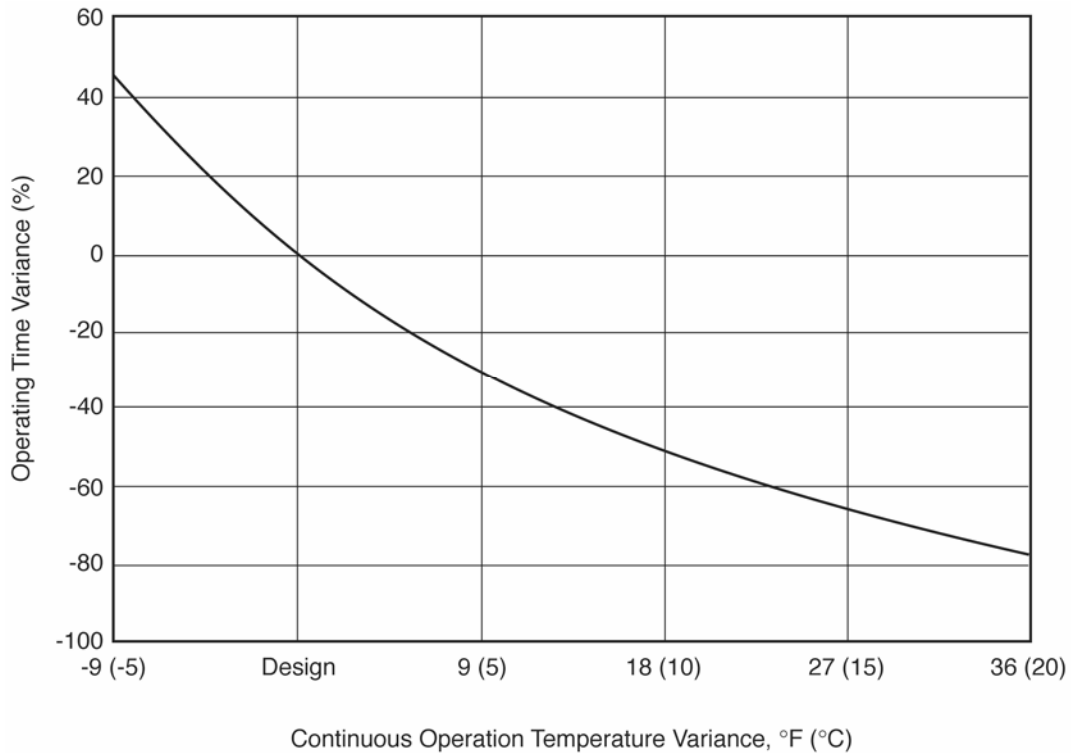


Figure 6-2
Effect of Temperature and Operating Time on Equivalent Creep Damage [3]

In practice, however, the pressure headers experience a range of stresses and temperatures for varying times. Creep strains accumulate during these stages. To evaluate the remaining creep life, a Life Fraction Rule can be used. This rule states that creep rupture occurs when the sum of all the fractions of the rupture life at different stress-temperature combinations becomes unity and can be defined as follows:

$$\sum \left(\frac{t_1}{t_{R1}} + \frac{t_2}{t_{R2}} + \frac{t_3}{t_{R3}} + \dots \right) = 1$$

where t_1 is the time spent at a particular stress-temperature combination and where the time to rupture is t_{R1} .

As mentioned in Section 3, thermal cracking in the gland area can be caused by a temperature difference between the gland sealing steam and the surface of the rotor. To prevent thermal cracking, the temperature difference should be kept to a minimum. In reality, however, the temperatures between the gland sealing steam and the rotor surface vary under different operating conditions. To allow an assessment of potential damage, manufacturers supply thermocouples in the cylinder and gland piping to monitor the difference between the rotor surface and steam sealing temperature. A curve showing the number of cycles that will initiate thermal cracking for a given temperature difference might be provided in the station design handbook. The general characteristics of such a curve are reproduced in Figure 6-3. Similar to the considerations previously outlined for creep regime, the percentage of rotor life used can be determined as:

$$\text{Percentage of life used} = \sum \frac{\text{Number of occurrences at } \Delta T}{\text{Estimated cycles to cracking at } \Delta T} \times 100$$

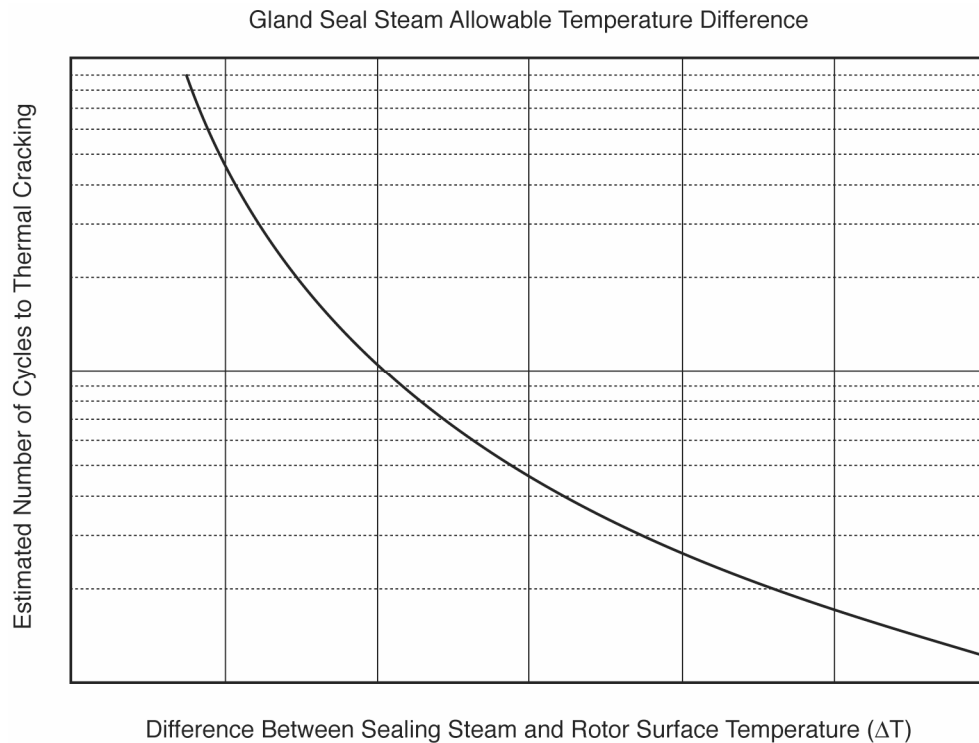


Figure 6-3
Estimated Cyclic Life of the Rotor Gland Area

A more general approach to high cycle fatigue is given by the Palmgren-Miners Rule. This method can be used to determine cumulative high cycle fatigue damage under irregular and cyclic loading and can be followed to evaluate the fractional damage; that is, the Palmgren-Miners Rule assesses the percentage of rotor life lost due to operating the unit n times at temperature difference ΔT :

$$\sum \left(\frac{n_1}{N_1} + \frac{n_2}{N_2} + \frac{n_3}{N_3} \dots \right) = 1$$

where n_1 is the number of applied cycles and N_1 is the pertinent fatigue life limit.

7

COMPONENT MAINTENANCE

7.1 General Maintenance Considerations

Common maintenance recommendations for the steam seal components are included in this section. In all cases, specific manufacturer procedures, recommendations, and service support should be incorporated in the maintenance program of the steam seal components.

7.1.1 Aging and Degradation Mechanisms

Some components have aging and degradation mechanisms that are identifiable over the service life of the equipment. These are often nonmetallic components, such as the following:

- O-ring seals
- Packing
- Gaskets
- Filters

Predominantly, the nonmetallic components perform some form of sealing function. Most tend to harden and lose their elasticity over time. Degradation of material properties results in improper sealing that, in turn, causes increased leakage. This condition, if not addressed, can lead to failure.

Paint and protective coverings tend to flake or peel due to exposure to heat, moisture, and steam. Lack of a protective layer accelerates corrosion. Excessive corrosion, if not addressed, can lead to failure. In addition, some components can degrade due to wear, erosion, corrosion, or fouling of metallic parts. Examples of these components include:

- Anti-friction bearings (for example, motor bearings and fan bearings)
- Valve seats and disks
- Heat exchangers

A list of parts and components that are likely to be affected by degradation over time should be identified and incorporated in the PM plan of each particular unit.

7.1.2 Spare Parts and Work Histories

A cognizant engineer or maintenance person should review spare parts recommendations made by equipment manufacturers. Parts obtained should be inventoried and stored under conditions recommended by the manufacturer. The frequency of PM/PdM activities along with the parts delivery time will determine the quantity and diversity of the required spare parts to be kept on hand.

An equipment and component work history, combined with industry experience and spare parts consumption, can indicate an adverse trend. For example, unexpectedly frequent motor or fan overhauls can be symptomatic of other problems (such as vibration, defective materials, or, possibly, maintenance performance problems) and could be investigated as a root cause.

7.1.3 Special Tools

All special tools furnished with equipment for installation or maintenance should be inventoried and stored in a controlled location. Enhancements developed using industry experience or by maintenance personnel should be identified and documented.

7.2 Component Maintenance

Listed in this section are maintenance recommendations for some of the steam seal components described in Section 4 of this report.

7.2.1 Control Valve Bodies

The maintenance recommendations for control valve bodies are as follows:

- Valve internals and parts are subject to normal wear and should be inspected and replaced on a regular basis. The periodicity of these inspections should be governed by the severity of the service conditions.
- The valve packing should be replaced every time the valve is disassembled for inspection. Regular inspections should be made of the packing area and the packing adjusted whenever a leak is observed.
- Some leakage should be expected with metal-to-metal seating in the valve body. If the leakage becomes excessive or if the steam cutting is determined to be excessive, the control valve should be disassembled for inspection. The seating surface can be repaired by grinding. Large nicks or deep steam cutting should be removed by machining. After grinding, the seating surfaces should be cleaned and checked using a blue dye. Repeat the grinding process if there is no well-defined blue ring around the seating surface.

7.2.2 Control Valve Actuators, Positioners, and Pressure Controllers

The maintenance recommendations for control valve actuators, positioners, and pressure controllers are as follows:

- To avoid personal injury and damage to the process system, the control valve and shutoff supply pressure and input signal lines to the positioner should be isolated before any disassembly is attempted.
- Manual operators or handwheels should be lubricated on a regular basis.
- The actuator/positioner should be monitored for air leaks and repaired as necessary.
- According to the manufacturer's recommendations, the actuator/positioner should be set to the proper starting point, and the range of travel should be set to ensure full valve plug travel.

7.2.3 Steam Seal Diverting Valves

The steam seal diverting valve temperature sensors should be recalibrated on a regular basis based on the severity of the service application.

7.2.4 Steam Seal Relief Valves

The maintenance recommendations for steam seal relief valves are as follows:

- Absolute cleanliness is essential when maintaining relief valves. The most common cause of malfunctions and leakage is dirt caught in the seating area.
- The relief valves should be disassembled and inspected on a regular basis.
- The seats should be lapped as required to remove all scratches or pits.
- Relief valves should be verified and reset on a regular basis. Blowdown operation should also be verified.

7.2.5 Steam Seal Exhauster Fan and Motor

The maintenance recommendations for the steam seal exhauster fan and motor are as follows:

- Maintenance on the fan or motor can be performed while the turbine is on-line if there is a redundant steam seal exhauster and adequate isolation can be achieved.
- The motor should be cleaned. The ventilation openings should be cleaned and any obstructions cleared.
- The motor and fan bearings should be lubricated on a regular basis in accordance with the manufacturer's recommendation.
- Fan and motor bearings should be evaluated on a regular basis using thermography or vibration analysis.

- If the fan or motor bearing is immersed in an oil reservoir, oil samples can be taken for analysis to monitor bearing wear.
- Exhauster motor collector rings, brushes, brush holders, and brush studs should be inspected for wear and dirt accumulation on a regular basis.

7.2.6 Steam Seal Exhauster: Heat Exchanger

The maintenance recommendations for the steam seal exhauster heat exchanger are as follows:

- The heat exchanger should be inspected and cleaned on a regular basis.
- Periodic inspections of the heat exchanger should be performed to determine the extent of corrosion, fouling, and scale deposits. Any leaking or defective tubes should be plugged.
- The heat exchanger tubes should be cleaned on a regular basis to prevent degraded efficiency.

7.2.7 Horizontal Joint Erosion

The maintenance recommendations for horizontal joint erosion are as follows:

- Experience has shown that the gland seal will erode over time due to water or hard particles.
- Packing casings also erode over time due to water or hard particles on the horizontal joints.
- Erosion can be repaired by welding with Inconel 82T on many of the eroded materials.
- Welding on the vertical joints of the packing casing can re-establish the required flatness.

Simple repairs typically take two to three days. Major repairs can be performed in five to seven days. Proper geometry of the seals, the width and height of each step, and concentricity and perpendicularity of all circumferential and radial surfaces must be verified at the end of the repair work. Replacement with a more erosion-resistant material should be considered if the gland seal erosion persists.

8

TROUBLESHOOTING AND FAILURE MODES

No standardized solutions will ever be able to resolve all the possible combinations of problems that could be encountered with the turbine steam seal system. Regardless of the specific problem or symptoms experienced, a disciplined approach to determining the root cause and optimal solution should be used. This section contains a general overview and approach to troubleshooting a steam seal component.

The information contained in this troubleshooting and failure modes section is intended to be general in nature and not specific to a manufacturer or vendor. When troubleshooting a steam seal component, personnel should refer to the vendor manual for specific information and troubleshooting steps.

In general, all troubleshooting should be based on the following three steps:

1. Identify the problem and what has changed. Without an accurate identification of the problem and what has changed, the probability of resolving the problem is not good. Some problems are intuitively obvious, and some require extensive troubleshooting and testing to completely understand the problem.
2. Define the desired approach and outcome. Is a temporary repair the best way to proceed? Should the component be replaced or repaired? Is a modification or change the best way to proceed? Are there Code or regulatory implications involved in the resolution?
3. Define the best corrective action approach. Identify the immediate, short-term, and long-term actions to resolve the problem and (one hopes) minimize the chance of a reoccurrence. Identify any changes to the PM/PdM or CM program to prevent a reoccurrence.

8.1 Failure Modes and Causes

The steam seal system can suffer from a variety of failure modes. This section outlines some of the most common problems.

Out-of-round seals can cause a localized rub. Shell humping, caused by water induction, typically results in seal rub at the bottom. Seal rub at the top and the bottom indicates improper alignment that might be general or local. Incorrect seal installation can cause an axial rub that, again, can be general or localized. This condition is exasperated by differential expansions of the rotor. Typical repair involves re-machining of the seal gland area. Excessive gland seal clearances can result in large steam leakage through the gland area that in turn could cause water contamination of the lubrication oil system. Analysis of the oil in the oil tank can determine presence of water in the lubrication system.

When looking at the effects of oversized seal clearances, it is important to consider not only the performance loss and associated monetary loss, but also why the seal clearances are large. There is often a good reason that the clearances are large, such as the design clearances not allowing for shaft lift during startup, distortion of the casing, and so on. Simply returning to the design values often does not restore performance because the seals rub out to the larger values during the first period of operation. Restart after overhaul can also be extended because of rubbing, causing vibration issues.

Improper pressure at either the pressure header or suction header can also cause excessive steam leakage through the gland area. This can again result in water contamination of the oil lubrication system. Adjusting steam seal pressure at the regulating valve and/or adjusting the vacuum at the exhausters fans can rectify this situation while the unit is operating.

In addition to a potential for oil contamination, a very large steam leak through the turbine gland seals can alter the temperature of the pedestals. This, in turn, would cause undesired thermal expansion and affect the alignment of turbine bearings. Often, large steam leaks at the gland seals can be detected visually during a startup of the unit. In addition, when the unit is off turning gear, a feeler gauge inspection is recommended to verify the proper gland seal clearance.

Failures of the steam seal system have proven to be costly. The Generating Availability Data System (GADS) database reports 14 occurrences between 2000 and 2006 that have resulted in a total of 89 events that were responsible for approximately 243 MWh per unit of lost generation annually. The INPO NPRDS/EPIX event database was used as a source of steam seal system failure modes. The source of information for this database is 73 U.S. nuclear generating plants that report Maintenance Rule activities. Table 8-1 summarizes the reported events from the INPO database.

Table 8-1
Steam Seal Failures

Event	Cause/Troubleshooting	Corrective Action	Common Failure Mode
A small steam leak was identified on the elbow of the 1-in. steam seal regulator drain line.	Result of long-term steam erosion.	Replaced leaking elbow. UT examined remaining sections of drain lines.	Steam erosion.
Steam seal evaporator low-level alarm.	1) Inadequate design of the electronic instruments used to sense the level. Instruments susceptible to harsh environmental conditions. Conductivity probes used to sense level are adversely affected by foreign material (rust, scale, and so forth) suspended and concentrated in the water due to boiling. 2) Inadequate procedures.	Modified the steam seal evaporator level instrumentation with a more reliable system.	Design problem.
Steam seal header low-pressure alarm.	1) Loss of turbine sealing steam caused by loss of steam seal evaporator condensate level control due to a plugged level instrument sensing line. 2) Unable to bypass steam seal evaporator and use main steam.	Sensing line was flushed and closed. Limit switch was reset.	Design problem.

8.2 Troubleshooting Control Valve Actuators and Positioners

If the actuator/positioner is malfunctioning or if it is causing sluggish or erratic operation, perform the following troubleshooting steps:

1. Verify that the range, starting point, and travel are properly set.
2. Clean the air paths and orifices.
3. Check the bellows area, looking for damage, misalignment, or leakage.
4. Check for a bent stem, binding, or any interference with the stem's movement.
5. Confirm that all the relays are functioning properly.
6. Check all soft components, such as O-rings and gaskets, for wear or damage.
7. Verify proper pressure settings on the air pilots for the AOVs.
8. Verify the integrity of the diaphragms in the AOVs.

9. Verify that there is no water or oil in the airlines to the pilots or the air operators. Oil or water in the airlines can cause erratic operation and deterioration of the diaphragms.
10. Verify that there is no paint on the valve stem where the stem passes through the packing gland. Painted stems can cause binding.

8.3 Troubleshooting Steam Seal System Isolation

Steam leaking into the steam seal system from the main steam system or auxiliary steam supplies has been proven to have a very significant impact on a plant's heat balance. In a documented case, steam leaking past a steam seal regulating valve that should have been closed and isolated caused a heat rate loss on the order of 100 Btu/kWh. A troubleshooting technique has been developed by Leak Detection Services, Inc., to determine if and when a steam seal regulating valve is not functioning as a tight shutoff valve.

The troubleshooting steps are as follows:

1. Determine the current power level.
2. Confirm that the power level is steady and well above the self-sealing power level.
3. Determine the current heat rate.
4. Determine the current steam seal pressure.
5. Record the position of all isolation valves.
6. Close the isolation valve (Valve E in Figure 4-1) upstream from the steam seal regulating valve (Valve A in Figure 4-1).
7. If the steam pressure does not oscillate or if any of the other valves (such as the spillover valve) does not change position, steam is not leaking past the steam seal regulating valve.
8. If the steam seal pressure fluctuates or other valves in the system (such as the spillover valve) fluctuate, there is leakage past the steam seal regulating valve, and it should be repaired.

Other control valves that should be leak-tight during normal operation at self-sealing power levels can be tested in a similar manner.

Additional information and explanation of troubleshooting steam seal system isolation valves can be found in the January 2002 presentation "Cycle Isolation Opportunities" [5].

9

MODIFICATIONS AND UPGRADES

As outlined in previous sections of this report, sealing between the rotating shaft of a turbine and the stationary casing is important in order to maximize the thermal performance of the unit. This is because the pressure inside the turbine casing under operating conditions is different from the atmospheric pressure outside.

To isolate the steam turbine, gland seal assemblies are installed at each end of the shaft. The conventional and most common gland seal geometry is outlined in Section 4.1. However, a number of new designs have been developed to increase the efficiency and extend the longevity of turbine gland seals. The following section outlines some of these improvements.

9.1 Retractable® Seals

Retractable® seals retract from their close clearance position under low-load and no-load conditions. This results in an additional clearance between the stationary seals and the rotating shaft, thereby reducing the likelihood for seal rub during startup and shutdown. This is especially important because excessive rotor vibration can be caused by rotor imbalance present during an initial startup. Such imbalance will be minimized before the unit reaches normal operating condition. In addition, the Retractable® seal also reduces the likelihood for seal rub as the unit passes through its critical speed zone(s), usually present below the synchronous speed.

Conventional gland seals are segmented, with each segment held in place by a flat radial spring. Retractable® seals employ coil springs between the seal segments, as shown in Figure 9-1. The coils are oriented in the tangential direction. Based on the manufacturer's input, this results in larger clearance during startup. However, as high-pressure steam enters the gland areas, the seal segments adjust to their design position. During steady-state operation, the clearance of the Retractable® seal is smaller than the clearance of the conventional labyrinth seal.

The Retractable® seals are easier to install because they have fewer parts. They prolong turbine life by eliminating wear during startup, increase plant turbine efficiency, and lower maintenance costs.

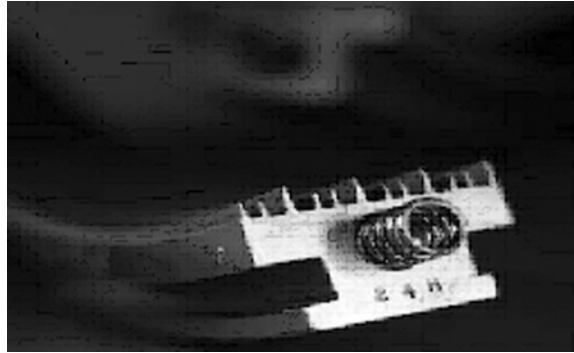


Figure 9-1
Retractable® Seal Segment and Coil Spring
Courtesy of Siemens Power Generation

9.2 Leaf Seals

A schematic outline of the leaf seal geometry is shown in Figure 9-2. In this design, thin metal plates or leaves, nested in series one after another, are positioned inclined in the circumferential direction. During operation, each leaf maintains a negligibly small clearance from the surface of the rotor due to a lifting force caused by a hydrodynamic pressure effect acting between the tip of the leaf and the rotor. Consequently, the wear in the seal area is minimized because there is no contact between the seal and the rotor. In addition, the plates provide rigidity in the axial direction. Therefore, the leaf seal is effective in high-pressure drop conditions.

Results of verification tests published by the OEM indicate that the leakage flow through the leaf seal is reduced to about one-third of the flow through a comparable conventional seal.

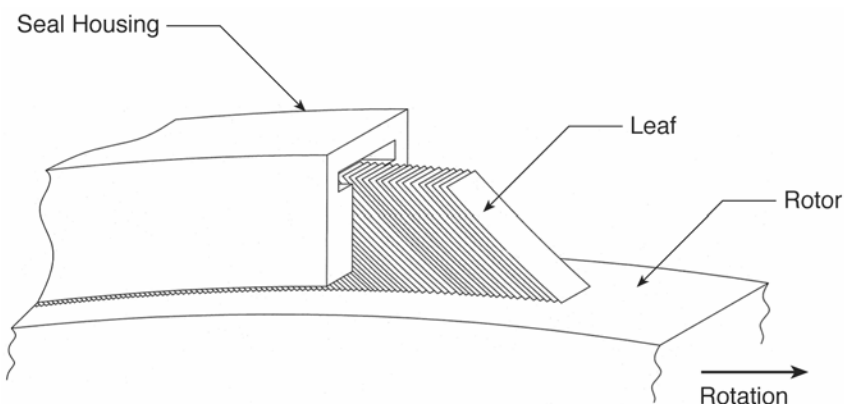


Figure 9-2
Outline of Leaf Seal Geometry

9.3 Active Clearance Control Seal

In active clearance control (ACC) seal design, the top and bottom segments of the labyrinth seal are movable in the radial direction. In order to open clearance, the segments are raised by a spring force when the unit is starting, stopping, or on turning gear operation. This reduces the probability for seal rub because most rotor vibrations occur during a startup.

When the load increases, the pressure drop across the seal will also increase. Consequently, each seal segment is shifted downstream. An intentional steam path is formed on the inlet side of the ACC seal segment. Thus, the pressure at the outer seal periphery increases. A pressure force is caused by differences in pressure at the inner and the outer circumference of the seal ring. By design, this force exceeds the spring force and, therefore, as the load increases, the seal segments shift radially inward.

9.4 Guardian® Seal

The geometry of the Guardian® seal is shown in Figure 9-3. In this design, a longer seal strip or post is introduced at the inlet and at the exit of the Guardian® seal segment. These posts are made of a special patented material with a low coefficient of friction. In addition, the subject material is non-galling but erosion resistant. The posts are set at a slightly lower radial clearance than the conventional seal strips. Therefore, during rubs, the Guardian® posts contact the rotor first, preventing damage to the rest of the seals. Furthermore, because of the low coefficient of friction, the Guardian® posts, when in contact with the rotor surface, generate substantially less heat than the conventional seals. This reduces galling on the outer surface of the rotor and prevents material damage in the heat-affected zone.

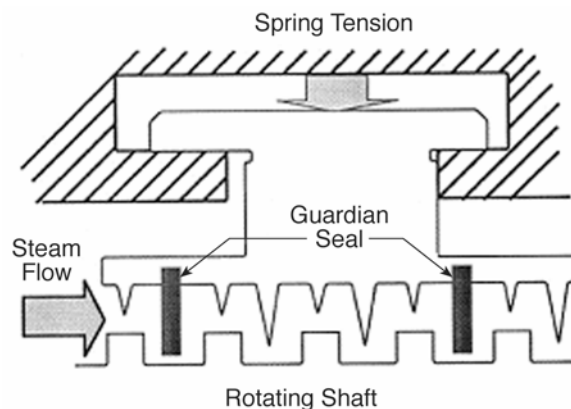


Figure 9-3

Guardian® Seal Geometry

Courtesy of Turbo Parts, LLC, a division of Mechanical Dynamics & Analysis, Ltd.

The remainder of the seal segment is constructed of 12Cr material, which is known to provide long service life in harsh steam environments.

Guardian® seals maintain tight clearance under a range of operations and extend the efficiency life of the unit. Light coil springs are used to hold the rings in a positive sealing position during startup, turning gear operation, and shutdown. These seals are applicable to both interstage and gland-sealing areas.

9.5 Vortex Shedder

A conventional seal leg features a cylindrical periphery at its steam-facing inner diameter. To prevent rub, typically a hot running clearance of 0.01–0.02 in. must be maintained between the stationary seal strip and the rotating part. However, to improve the efficiency of the conventional seal, a vortex shedder seal is recommended by the manufacturer.

The vortex shedder effect is created by dimpling of the seal surface facing the steam flow, as shown in Figure 9-4. The interrupted sealing surface causes a series of vortices, as shown in Figure 9-5. The resulting lower upstream pressure reduces leakage across the seal. Based on the manufacturer's evaluation, the vortex shedder reduces leakage by 5.7%.

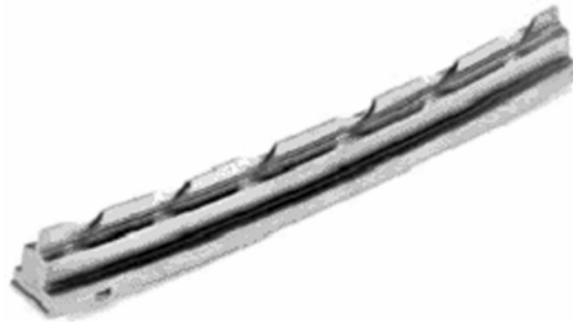


Figure 9-4

Vortex Shedder Seal

Courtesy of Mechanical Dynamics & Analysis, Ltd.

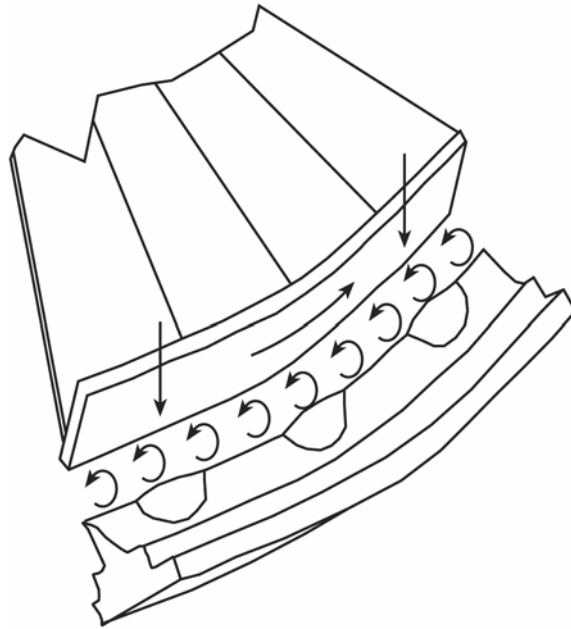


Figure 9-5
Vortex Shedder Effect
Courtesy of Mechanical Dynamics & Analysis, Ltd.

9.6 Brush Seal

A number of manufacturers promote a brush seal design. In this design, a brush-type element is installed between pairs of seal strips. In some designs, a groove in the labyrinth ring serves as a backing plate. Other manufacturers insert a backing plate into the seal ring structure. The function of the brush seal is to reduce seal clearance under a variety of turbine operating conditions. In most applications, the seals are installed inclined in the axial direction and adjust to a radial orientation with increase in turbine load. This approach provides clearance during a startup and thus reduces rotor-dynamic concerns.

Based on OEM input, a brush seal reduces a leakage area by as much as 80% and can result in 0.1–0.2% heat rate improvement on a large (400–800-MW) turbine.

A number of brush seals, sometimes known as *bristle packs*, can be applied in series in the gland areas of a turbine. Figure 9-6 illustrates a typical two-stage brush seal segment. Some manufacturers use Cobalt Superalloy (Haynes 25) for the brush seals.



Two-Stage Brush Segment

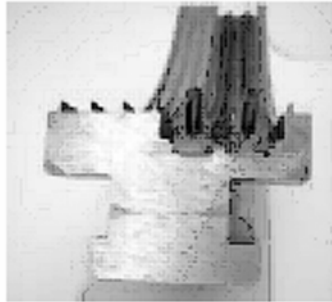


Figure 9-6
Two-Stage Brush Seal
Courtesy of Siemens Power Generation

9.7 Seal with Abradable Coating

In this approach, an abradable coating is applied by spray between the standard seal segments, as illustrated in Figure 9-7. This reduces seal clearance and thus reduces leakage flow. During rub, the rotor seals, which are harder than the abradable material, will not be damaged.

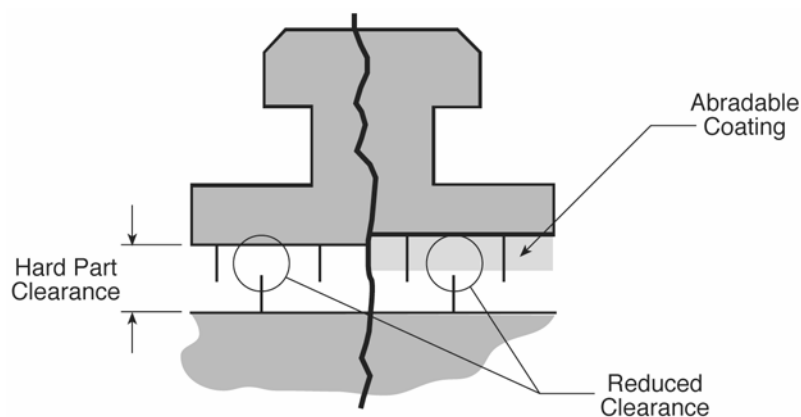


Figure 9-7
Typical Abradable Seal Arrangement
Courtesy of Siemens Power Generation

9.8 Advanced Labyrinth Seal Design

The effects of different seal leg geometry on leakage control are evaluated in a related EPRI report, *Advanced Steam Labyrinth Seal Design: Phase 1 Initial Concept Evaluation* [6]. CFD analyses were conducted on a number of different shapes to evaluate their efficiency; the efficiencies were then compared to a baseline. A single, long, C-shaped sharp edge with three short knives, shown in Figure 9-8, was determined to be the most efficient seal arrangement in the 2–10 pressure ratio range. It was followed closely by the single, long, C-shaped flat edge with three short knives, shown in Figure 9-9. The latter seal is recommended because the curved C-shaped flat seal leg is thought to be less sensitive to rub.

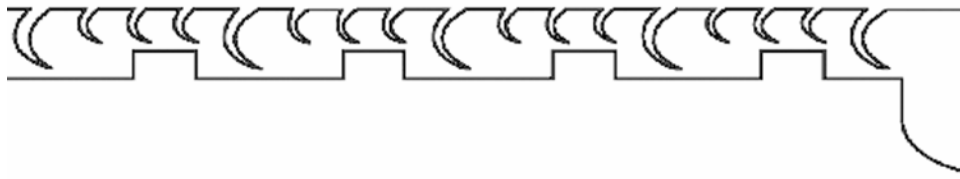


Figure 9-8
Seal with a Single, Long, C-Shaped Sharp Edge with Three Short Knives [6]

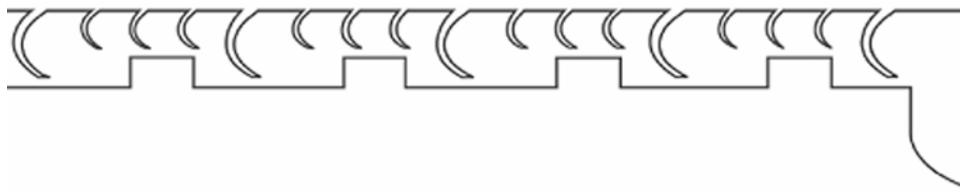


Figure 9-9
Seal with a Single, Long, C-Shaped Flat Edge with Three Short Knives [6]

9.9 Other Upgrades

Some additional upgrades that are considered include:

- Transducers to provide monitoring of steam seal feed and header pressures
- Steam seal valve position feedback
- Additional pressure and temperature monitoring of the steam seal system

10

SAFETY ISSUES

10.1 Personnel Safety Issues

Operation of steam seal valves should be performed by knowledgeable, trained individuals to prevent burns from hot components or leaking steam. All the pertinent Occupational Safety and Health Administration (OSHA) regulations must be adhered to when working on the steam seal system.

10.2 Equipment Safety Issues

Do not admit steam to the glands of an idle turbine because varying degrees of corrosion or erosion or a bowed rotor can result.

Ensure that the steam seal system is in operation prior to establishing a condenser vacuum. Dirt and debris could be drawn into the turbine glands if the seal system is not in operation.

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