WATERTUBE BOILERS

Table of Contents

List of Tables

1.0 SCOPE

This data sheet covers package and field erected watertube boilers with a maximum allowable working pressure (MAWP) greater than 15 psi (103 kPa) steam and a maximum allowable working temperature (MAWT) greater than 250°F (121°C) for high-temperature water boilers utilized in a wide range of applications. The guidance provided includes operator programs, inspection, testing and maintenance programs, and water treatment programs for boiler feedwater quality, boiler water quality and steam purity. Guidance is also provided for boiler design, construction, operation and safety systems.

Heat recovery boilers are covered in Data Sheet 6-14, *Heat Recovery Boilers,* in conjunction with this data sheet.

1.1 Changes

April 2025. Interim revision. Guidance on establishing and implementing a boiler water treatment program, including guidance on boiler feedwater quality, boiler water quality and steam purity was completely revised and improved. Select editorial changes were also made for additional clarity.

2.0 LOSS PREVENTION RECOMMENDATIONS

2.1 Training

Train operators on standard and emergency operating procedures (SOPs and EOPs). See Data Sheet 10-8, *Operators*, for guidance on developing operator programs. Permit only personnel specifically trained in boiler operation to operate or troubleshoot a boiler. Improper operation of a boiler can have consequences ranging from inconvenience due to loss of heat to interruption of production and serious damage of property (surrounding equipment or structures in addition to the boiler). The possibility of improper operation can be limited by having a knowledgeable operator at the boiler or readily dispatchable to the boiler. The National Board of Boiler and Pressure Vessel Inspectors also supports attendance of boilers in industrial applications by trained operators.[1]

2.1.1 Operator Training

Provide operator training and qualification commensurate with the particular boiler type and application. (See 3.1.2, Training.)

2.1.1.1 An operator of a small package type heating boiler in a residential building should be familiar with the boiler manufacturer's recommended operating practice. This practice may be very simple and training may be limited to reading the manufacturer's manual and self familiarization with the boiler controls. Little, if any, follow-up training may be necessary. *American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME) Section VI,* Part 6.02 ''Safety'' indicates, ''Only properly trained qualified personnel should work on or operate mechanical equipment, and adequate supervision should be provided.''[2]

2.1.1.2 Train operators of boilers in manufacturing facilities for the specific boilers to be operated and provide classroom training on general boiler operation. Operators in training should also be taught on the job by a knowledgeable operator who also participates in the decision to elevate a trainee to fully qualified operator. Complete a limited review of the qualifications of each operator on at least an annual basis. This review would determine the need for and extent of any follow-up training. ASME Section VII, Part C2.110 ''Operator Training'' indicates operators should have ''knowledge of fundamentals...familiarity with equipment...suitable background of training and experience.''[3]

2.1.1.3 Thoroughly train operators of boilers in utility type occupancies and process industries on the specific boilers to be operated in addition to general boiler operation training. Keep records of all training provided for industrial and utility boiler operators. Conduct a simulated emergency drill and a performance evaluation at least annually. Incorporate the boiler and auxiliary equipment manufacturers' recommendations in the training program. An industry accepted standard training program, as available through utility or process

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[1] *The National Board of Boiler and Pressure Vessel Inspectors, The Ten Demandments,* NB-100, Rev 4 (pamphlet, Columbus, Ohio: The National Board of Boiler and Pressure Vessel Inspectors, 1992), page 6.
[2] *The American Society of Mechanical Engineers, Boiler and Pressure Vessel Code; Section VI — Recommended Rules for the Care and Operation of Heating Boilers* (New York: ASME, 1992), page 49.
[3] *The American Society of Mechanical Engineers, Boiler and Pressure Vessel Code; Section VII — Recommended Guidelines for the Care of Power Boilers (New York: ASME, 1992), page 9.*

industry associations and trade schools or colleges, may be useful in developing the program. As indicated in recommendation 2 above, ASME Section VII indicates operators should have a ‘‘suitable background of training and experience.’’

2.1.2 Attendance

2.1.2.1 For fully automatic boilers in low exposure occupancies (heating or hot water supply boilers in residential or commercial buildings), the operator may be an employee or an ‘‘on call’’ contractor.

2.1.2.2 Provide an on site, trained operator for fully automatic boilers in moderate exposure occupancies (process steam or hot water boilers in manufacturing facilities) during all production hours. If loss of such a boiler could adversely impact normal operations, an operator should be immediately available, preferably stationed in the boiler room. If such boilers are operated from a remote control room, the operator may be stationed in the control room rather than at the boiler. (See Section 3.1.1, Operator Attendance.)

2.1.2.3 Provide continuous attendance by a fully trained operator for fully automatic boilers in process industries and utilities where loss of any one boiler is essential to normal operations. (See Section 3.1.1, Operator Attendance.)

2.1.2.4 Provide continuous attendance by a trained operator for any boiler that is not fully automatic, regardless of application.

In addition, implement recommendations on operator attendance in Data Sheet 6-12, *Low-Water Protection*.

2.2 Operation and Maintenance

2.2.1 Inspection, Testing and Maintenance Program

2.2.1.1 Establish and implement a watertube boiler inspection, testing, and maintenance program. See Data Sheet 9-0, *Asset Integrity*, for guidance on developing an asset integrity program. (See Section 3.1.3, Inspection, Testing, and Maintenance, and Appendix C.1, Essential Elements of an Inspection, Testing, and Maintenance Program).

1. Base inspection, testing, and maintenance programs for boilers in low exposure occupancies (heating or hot water supply boilers in residential or commercial buildings) on the manufacturer’s recommendations. Actual maintenance may be performed by any qualified boiler repair contractor. Records of maintenance may be limited to a check-off sheet at the boiler and the contractor’s activity report.

2. Incorporate specific inspection, testing, and maintenance recommended by the boiler manufacturer and the general guidance of an accepted standard, such as ASME Section VI and *Section VII* in the program for a boiler in a moderate exposure occupancy (process steam or hot water boiler in a manufacturing facility). Maintenance records may be a combination of log books, contractor activity reports, and check-off sheets at the boiler.

3. Incorporate the manufacturer’s specific recommendations and the general guidance of an accepted standard in the program for boilers in process industries and utilities where loss of any one boiler is essential to normal operations. Some maintenance actions may be based on operating experience, or based on condition and performance monitoring. Organize equipment and maintenance records to permit inspection, testing, and maintenance action planning that will minimize unplanned shutdowns.

4. In addition to repairing adverse conditions discovered during inspection, testing, maintenance or operation, the cause of the condition should also be determined and corrective action taken to prevent recurrence.

2.2.2 Welding

Follow the requirements of the *National Board Inspection Code (NBIC),* current edition for any boiler alteration or repair. Permit only organizations having a National Board of Boiler and Pressure Vessel Inspectors’ (NB) repair authorization to perform welding on boiler pressure parts. If an NB authorized repair organization is not available, qualify the repairing organization in accordance with the *NBIC.* Outside North America, follow the local code or if there is none, follow the *NBIC.* (See Sections 3.1.3.1, Welding, and C.6, Waterside Inspections.)

Review other codes and references such as ASME Section I or IV; ASME/ANSI B31.1, *Power Piping*, and any technical advisory bulletins from the boiler manufacturer to assure the repair or alteration will achieve long term economical results. Trade associations such as the Electric Power Research Institute (EPRI) and the Technical Association of the Pulp and Paper Industry (TAPPI) also provide advisory guidelines for boiler repairs.

Welded repair of riveted boilers should be a choice of last resort and only done with prior permission of the authority having jurisdiction. Repair of riveted joints should preferably be done by calking. Welding may conceal defects that might not be apparent on visual inspection (cracking under lap joints, broken rivets) but would be revealed by leakage.

2.2.3 Tube Repair or Replacement

2.2.3.1 Establish and implement a tube repair and replacement program consistent with the operating and availability requirements of the boiler and which is satisfactory to the authority having jurisdiction. (See 3.1.3.2)

1. As a function of normal operation, boiler tube thickness is reduced. The rate of thinning is dependent on tube material, boiler design and boiler operation. Thinning occurs on both the internal and the external tube surfaces. Small areas thinned by external corrosion or erosion may be restored by welding as described in NBIC, Part RD, Repair Methods. Restoration by welding can be used for external thinning so long as sufficient tube material remains to prevent burning through during the repair. Restoration by welding for internal thinning should not be used. Internally thinned tubes should be replaced when the minimum thickness (described below) is reached.

2. Thinning over a large area of a single tube or involving several tubes is best corrected by tube replacement. Replace tubes in accordance with specific jurisdictional requirements or in accordance with an owner defined program acceptable to the authority having jurisdiction.

   a) In some special applications (such as municipal waste fuel fired boilers, black liquor recovery boilers) do not permit tubes to thin below the minimum thickness required by Section I of the ASME Code regardless of the boiler maximum allowable working pressure (MAWP). In these special applications, wastage rates may be highly variable (result in unplanned outage) and, for black liquor recovery boilers, tube failure may lead to an explosive reaction between the boiler water and the molten smelt. (See also section 2.2.4.)

   b) When deciding whether or not to replace a tube or tubes, consider boiler operating conditions such as internal deposits or scale, flame impingement, corrosive nature of flue gases, abrasive nature of the fuel ash and any other factors that could accelerate tube thinning. Modifying the flue gas velocity and path is sometimes effective in limiting external erosion. Modifying boiler water treatment is sometimes effective in limiting internal corrosion. In the absence of specific jurisdictional requirements or an owner defined program, apply the following guidelines.

Industry operating experience shows tubes of SA-213 Grades T11 (1¼ Cr-½ Mo-Si) and T22 (2¼ Cr-1 Mo) material that are 20 or more years old, operating at above 900°F (482°C) and 1200 psi (8,300 kPa) or more and in cyclic service have proven more likely to fail from creep. The higher the operating temperature, the more likely the tubes will fail due to creep. The higher temperature causes accelerated spheroidization of the lamellar iron carbide and therefore accelerated weakening of the material causing failure by creep. If a boiler having superheater or reheater tubes meeting these conditions is essential to production, complete a study to determine remaining life during the next planned outage. The frequency and extent of future inspections for creep and creep fatigue damage is based on the findings of the initial inspection. Tube life may be maximized by careful original design to balance heat transfer among all the tubes or by retrofitting existing boilers with flow control devices (orifices) in the tubes.

2.2.4 Evaluating Tube Thickness Using Allowable Stresses from the Applicable Edition of the ASME Boiler & Pressure Vessel Code, or Other Locally Acceptable Code

The following criteria is derived from and consistent with National Board Inspection Code (NBIC) Inquiry 98-14.

When all the following conditions are met, a tube can be evaluated using allowable stresses from the applicable editions of the ASME Boiler and Pressure Vessel Code:

   a) An ‘‘R’’ Certificate holder verifies (by calculation or other means) that the tube can be satisfactorily operated (e.g., stiffness, buckling, external mechanical loading, etc.).

b) The tube was constructed to the 1968 Edition or later edition/addenda of the ASME Boiler & Pressure Vessel Code.

c) The tube material specification to which the tube was manufactured is no less stringent than the current specification for that material in the ASME Boiler & Pressure Vessel Code (i.e., the tube meets all the relevant requirements which permit the higher allowable stress values including reinforcement, toughness, examination, etc.).

d) Use of the allowable stresses is acceptable to the cognizant parties (i.e., inspector and/or authority having jurisdiction, as appropriate).

e) All other requirements of applicable codes and standards are met and use of the higher allowable stresses is properly documented.

f) The evaluation is based on the lowest measured tube wall thickness and the tube design pressure and temperature.

2.2.5 Thick Wall Component Evaluation and Repair

Refer to Section 3.1.3.4, Hydrostatic Testing , for more information.

2.2.5.1. Thick wall components (drums, headers, pipes) are subject to fatigue cracking. Drums of SA-212 Grade B material (used in the 1960s) have proven to be susceptible to cold working or localized over stressing. Welded repair of this material has proven to require heat treatment to avoid cracking. Make a close visual inspection of welds and rolled tube joints in drums of SA-212 Grade B material, particularly if tubes have been re-rolled or if welded repairs have been made on the drums. If welded repair of SA-212 Grade B drums is necessary, include heat treatment in the welding procedure.[4]

2.2.5.2. Inspect superheater or reheater headers of SA-335 Grade P11 material (1-¼ Cr-½ Mo-Si) built between 1951 and 1966 operating above 900°F (482°C) for creep and creep-fatigue at the next planned outage. Due to adverse experience, the requirements for Grade P11 material in the ASME material specification SA-335 were revised in 1966. Experience has shown that cracks are likely to develop in the tube hole ligaments and at all header welds.[5] Base the frequency and extent of future inspections for creep and creep fatigue damage on the findings of the initial inspection.

2.2.5.3. Boilers having either P11 (1-½ Cr-½ Mo-Si) or P22 (2-¼ Cr-1 Mo) headers may exhibit creep or creep fatigue cracking depending on service conditions. Boilers operating over 1200 psi (8,300 kPa), 20 or more years old and in cyclic service are of primary concern. Examine all external welds of the headers nondestructively at the next planned outage and consider examining two adjacent tube bore holes in the highest heat section of the header for creep cracking. Base the frequency and extent of future inspections on the findings of the initial inspection.

2.2.6 Hydrostatic Testing

2.2.6.1 Hydrostatic testing may be required to verify the integrity of newly fabricated pressure vessels and should follow code of construction requirements. The repair or alteration of in-service pressure vessels may also require liquid pressure testing or other methods approved by the inspector (i.e., non-destructive examination or pneumatic testing) and should follow code requirements for repair and alteration. When performing hydrostatic testing, review material specifications and determine the highest boiler material transition temperature. Heat the hydrostatic test fluid (generally water) as necessary to ensure boiler material temperature will be above the material transition temperature during the hydrostatic test. Failure to maintain temperature above the material transition temperature may result in brittle fracture, particularly of thick wall components. (See Section 3.1.3.4, Hydrostatic Testing.)

2.2.7 Boiler Operation

2.2.7.1. Operate boilers within the limits specified by the manufacturer. Exceeding any boiler design limit shortens the remaining useful life of the boiler and may lead to catastrophic failure. See Data Sheet 10-8, *Operators*, for guidance on developing operator programs.

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[4] *F.W. Tatar, FM Global Met Lab*, October 15, 1991 letter to FM Milwaukee D.O. regarding Report No. ML-91-91.
[5] *American Insurance Services Group, Inc., Fossil-Fired Utility/Industrial Boiler Life Assessment/Extension.* Boiler and Machinery Engineering Report (New York: American Insurance Services Group, Inc., 1991) page 10.

Understand and observe the operating limits of an existing boiler. These may differ from the stamping on the boiler due to boiler repair or replacement of ancillary devices. For example, a boiler designed for a given steam flow at a high pressure may not have a sufficiently large steam drum to deliver the same flow of dry steam at a much lower pressure. As another example, a change to a fuel of higher heating value may require additional safety valve relief capacity. Review any change in the operating parameters of an existing boiler with the boiler manufacturer and FM to determine if the boiler design and condition is compatible and satisfactory for the new parameters.

2.2.7.2 Provide controls so that boiler operation is maintained within design limits. Provide steam drum and superheater and reheater header metal temperature indicators on all field erected boilers.

Provide documented standard and emergency operating procedures which are readily available in the boiler control room. Clearly state in these procedures that the operator has the authority and is expected to promptly shut down the boiler if an emergency condition develops. Some conditions that might require a prompt, orderly shutdown are contamination of feedwater, significant reduction of feedwater flow, high or low drum level, loss of instrument air, fire in flue gas cleaning equipment and boiler safety valve operation. Each facility should identify specific emergency conditions that could occur and develop appropriate responses for the operator. For all boilers, develop emergency operating procedures such as process upset (sudden change in demand), high or low drum level, loss of feedwater, tube leak and control system failure. These emergency operating procedures are necessary even for boilers having fully automated controls that can shut down the boiler if safe limits are exceeded. The operator is the final line of defense in preventing boiler losses.

Also develop standard operating procedures for normal startup, normal shutdown, and normal operation. Develop specific procedures for the particular boiler application (steam, high-temperature water) and boiler design (forced or pumped circulation, thermal or natural circulation, once-through or supercritical pressure). (Also see Data Sheet 6-2, *Pulverized Coal Fired Boilers,* 6-4, *Oil and Gas-Fired Single-Burner Boilers* and 6-5, *Oil and Gas Fired Multiple-Burner Boilers*.)

2.2.8 Water Treatment Programs

2.2.8.1 Establish and implement a documented site, process, and unit-specific water treatment program as part of the boiler's asset integrity program. Effective water treatment is essential to control potential damage mechanisms that can impact the boiler system, downstream equipment and/or processes, ensuring boiler system integrity and reliability to operate as designed.

The primary goals of an effective water treatment program include:

A. Prevent the accumulation of scale and deposits in the boiler and downstream processes and/or equipment

B. Removal or control of dissolved gases from the water

C. Protection of the boiler against corrosion

D. Elimination of carryover in the steam to protect downstream processes and/or equipment

E. Maintenance of proper pH levels

The scope of the program is based on the specific application, including the site, process and/or unit specific operating/service conditions (i.e. boiler unit type and operating pressure) the boiler system is designed to operate within (integrity operating windows) to meet demand requirements and control damage mechanisms. This scope includes downstream equipment or process operating parameters taking a condition-based approach.

The type of external and internal water treatment is selected, operated and maintained, based upon the integrity operating windows and the established water chemistry limits. Site, process and unit-specific water quality and steam purity target parameter ranges and excursion limits are established based upon OEM/ industry recommended chemistry limits. Refer to Data Sheet 13-3, *Steam Turbines*, for steam purity parameter guidance.

A qualified water treatment consultant and/or qualified in-house personnel is used to manage and support efficacy of the water treatment program. The consultant/in-house personnel should test and validate readings, and should be involved in outage inspections and deposit analysis. Water treatment program testing scope and frequency depends on the boiler application (see Section 2.2.8.2).

Key water quality and steam purity parameters are monitored at the locations and frequencies (grab or continuous) specified by the water treatment program. Water treatment equipment, including condition monitoring equipment, is inspected, tested and maintained/calibrated to monitor the specified parameters. Boiler feedwater quality (external to the boiler - raw/make up water supply/condensate), boiler water quality (internal to the boiler) and steam purity is maintained within the boiler's original equipment manufacturer (OEM) recommended (i.e., unit specific) and/or industry guideline parameter ranges and chemistry limits.

SOPs are in place for normal operation of the water treatment processes and equipment. Operators are adequately trained on water treatment SOPs, including both initial and refresher training.

An excursion management process is in place as part of the water treatment program to review and promptly/appropriately respond to water treatment program parameter excursions (i.e. parameters outside of established limits).

EOPs are in place to address parameter excursions. They include any required corrective actions and how long an excursion is permissible before additional mitigation is required—up to and including shutdown of the boiler. Operators are adequately trained on water treatment EOPs. including both initial and refresher training. The root cause of the excursion is reviewed to help prevent any reoccurrence and to make program changes as needed.

Boiler feedwater quality, boiler water quality and steam purity program results are tracked and trended within parameters. This tracking includes testing and reporting of results from qualified water treatment consultant and/or in-house personnel. Regular reviews are conducted by the qualified water treatment consultant and/or qualified in-house personnel to verify program compliance and efficacy. This includes review of excursions, tracking and trending results, and internal/dismantle inspection results to analyze deposits and program performance.

2.2.8.2 The efficacy of a water treatment program can be determined primarily through water/steam sampling, equipment inspections and deposit loading analysis. The scope, frequency, and sampling locations of boiler feed water/boiler water quality, and steam purity testing depend on boiler application. Annual testing may be adequate for high-temperature water boilers, provided system make-up is minimal. Test feedwater for high pressure steam boilers at least daily. Boilers having chemical treatment injected into the drum should have monitoring instruments on the boiler blowdown to detect adverse conditions. Depending on application and operating experience, testing may be needed on each shift or multiple times per shift. In some critical process and elevated pressure (over 400 psi [2,800 kPa]) applications, continuous monitoring instrumentation should be provided. Consult the boiler manufacturer, industry guidelines/standards, the qualified water treatment consultant and/or in-house personnel. The scope and frequency of testing is application dependent and condition-based to manage the damage mechanisms that could lead to boiler system and/or downstream equipment or process breakdown.

During each internal inspection of a boiler, evaluate the condition of water side surfaces and determine the effectiveness of the water treatment program. If corrosion or deposits are noted, make appropriate adjustments to the program. If water-side deposits accumulate to the point where boiler and/or downstream equipment performance/reliability will be adversely impacted, consider mechanical or chemical cleaning of the boiler. Boilers having satisfactory water treatment programs may rarely or never need any mechanical or chemical cleaning. Visually apparent deposition can sometimes be reduced by modification of the water treatment program.

As steam boiler operating pressure increases, the tolerable amount of boiler water contaminants decreases. Water treatment programs should include methods to determine internal deposit loading on heat transfer surfaces. Acceptable methods may include internal visual inspection, borescope inspection of areas that are difficult to access, removing a sample section of a tube for deposition and metallurgical analysis, and non-destructive examination methods such as ultrasonic examination. Wall tube temperature readings and trends may also provide indication of deposition for boilers equipped with wall thermocouples. Inspection activities should be focused on areas of low circulation and/or high heat transfer rates. Any internal tube deposition results in increased tube metal temperature which increases tube wastage rate.

Refer to Section 3.1.4, Water Quality and Steam Purity, and Appendix D, Water Treatment Programs, for additional guidance.

Refer to Data Sheet 13-3, *Steam Turbines*, for additional guidance on steam purity.

2.3 Equipment and Processes

2.3.1 Safety Appurtenances and Fuel Combustion Controls

2.3.1.1 Provide safety or safety relief valve relieving capacity of at least the maximum output rating determined by the boiler manufacturer. If additional fuel firing capacity or heat transfer surface is retrofitted, recalculate and provide additional relieving capacity of at least the current maximum boiler output.

Provide safety or safety relief valves as required by local jurisdictional or regulatory authority, original code of construction, standard, or specification used in the construction of the boiler. Also refer to ASME Section I, IV, or XIII as appropriate, and as described in Data Sheet 12-43, *Pressure Relief Devices.* For maintenance, follow the valve manufacturer's recommendations, the NBIC, ASME Section VI or VII or Data Sheet 12-43.

2.3.1.2 Consider providing pressure relief devices that can be isolated from the boiler and set to operate below the set pressure of ASME Code required safety valves for steam boilers that are essential to plant operations. These devices can prevent unnecessary operation of the Code required safety valves due to sudden changes in boiler load, such as from a turbine or process equipment trip. Safety valves may leak after operation and require interruption of production to repair or replace the valve. Pressure relief devices, such as power-actuated relief valves, are intended for this service and can be isolated from the boiler for repair.

2.3.1.3 Provide and maintain fuel combustion controls as recommended in Data Sheets 6-7, *Fluidized Bed Boilers*; 6-13, *Waste Fuel Fired Facilities;* 6-14, *Heat Recovery Boilers;* 6-21, *Chemical Recovery Boilers;* 6-2, *Pulverized Coal-Fired Boilers*; 6-6, *Boiler-Furnaces Implosion;* 6-4, *Oil- and Gas-Fired Single-Burner Boilers* and 6-5, *Oil- and Gas-Fired Multiple-Burner Boilers.* Provide fuel controls, particularly for multi-fuel boilers, to limit combined firing rate to the maximum design heat rate.

2.3.1.4. Provide and maintain low-water alarm and low-low-water trip systems (or low-flow alarm and trip systems for once-through boilers) as recommended in Data Sheet 6-12, *Low-Water Protection for Boilers*. For boilers supplying steam to steam turbines, provide and maintain high-water alarm and high-high-water trip systems. See Data Sheet 13-3, *Steam Turbines*. For non-turbine applications, a high-water alarm should be provided and maintained and a high-high-water trip should be considered, based upon process and equipment sensitivity to carryover.

2.3.2 Boiler Design and Construction

2.3.2.1 Design and construct new boilers to meet or exceed the requirements in the current edition of *ASME Section I* or Section IV. Outside North America, implement a similar construction code promulgated by the jurisdiction. If there is no local code, implement the appropriate *ASME Code* section.

Complying with the ASME Code will better ensure pressure part integrity over a reasonable operating lifetime. The ASME Code provides minimum design and construction rules. Specific boiler application may require design that exceeds these minimums. For boiler construction outside North America (where the ASME Code may not be applicable) a comparable code, acceptable to the authority having jurisdiction, should be used.

2.3.2.2 Carefully develop the intended operating parameters over the expected life of the boiler so the boiler manufacturer can design the boiler to safely meet these parameters. Anticipate application changes over the life of the boiler, such as changing operation from base load to load following or cyclic operation. Determine the maximum steam flow for each expected operating pressure. For a given steam flow, a larger steam drum will be needed to prevent carryover at lower pressure than higher pressure. Provide a corrosion allowance in boilers designed for corrosive fuels, such as municipal solid waste or chemical recovery. Consider membrane wall construction with composite tubes if such boilers are operated over 900 psi (6,200 kPa). Design, instrument and operate superheater and reheater headers having design temperatures of 900°F (482°C) or more to minimize temperature excursions beyond design limits along the entire header length.

Process boilers selected on basis of process pressure and average steam capacity may not have the reserve capacity needed to meet sudden steam demands such as from rapid cut in of large cooking vessels (batch digesters, rendering cookers). A waste fuel fired boiler originally purchased based on steam demand may not be able to handle incineration of all the waste fuel materials and meet required emission limits. A process boiler designed for continuous operation that is operated intermittently may not be capable of withstanding the thermal stresses due to cyclic operation. These are some of many possible examples.

2.3.2.3. Include water treatment equipment (make-up, condensate and feedwater) appropriate for the boiler operating pressure and sized for the maximum possible steam demand or start-up demand, whichever is greater, in the original boiler installation design. The combination of treated water storage and treatment equipment should provide treated water to meet the flow and duration of the maximum demand period. Improperly sized water treatment equipment has resulted in untreated water entering boilers. Loss experience indicates tube deposits result from inadequate treatment of make-up water and from inadequate treatment of condensate. The deposits lead to overheating and tube failure.

2.4 Contingency Planning

2.4.1 Equipment Contingency Planning

When a watertube boiler breakdown would result in an unplanned outage to site processes and systems considered key to the continuity of operations, develop and maintain a documented, viable watertube boiler equipment contingency plan per Data Sheet 9-0, *Asset Integrity*. See Appendix C of that data sheet for guidance on the process of developing and maintaining a viable equipment contingency plan. Also refer to sparing, rental, and redundant equipment mitigation strategy guidance in that data sheet.

In addition, include the following elements in the contingency planning process specific to watertube boilers:

A. Evaluate potential rental/temporary equipment options for package watertube boilers, considering required capacities.

B. Review required connections to the production, utility, and support systems for rental equipment.

C. Identify sources of boiler repair services and materials can expedite repairs.

D. For field erected boilers, review equipment breakdown sparing options of longer lead time tube sections, depending on the design and materials of construction.

3.0 SUPPORT FOR RECOMMENDATIONS

3.1 Background Information

3.1.1 Operator Attendance

Boilers that are not attended must have failsafe controls that shut down the boiler any time a condition arises that could lead to an undesirable outcome. Emergency shutdown of boilers is not desirable due to cyclic fatigue effects and process interruption. In the cases of small, package type boilers operating at relatively low pressures (250 psi [1,700 kPa] or less), cyclic fatigue due to emergency shutdown may not be a significant factor. In process industries with excess steam capacity, loss of one boiler due to an emergency shutdown may not adversely affect the process. In these cases, less than full time operator attendance may be acceptable. However, some jurisdictions require and the National Board recommends full time attendance of any steam boiler operating over 15 psi (100 kPa).

Some level of supervision is needed even for fully automatic boilers. A knowledgeable operator is needed to periodically observe and determine the operating condition of a boiler, test the operating and safety controls and check the condition of the boiler feedwater. A knowledgeable operator can maximize the operating reliability and efficiency of an automatic boiler.

If cyclic fatigue from emergency shutdown is undesirable or if process interruption cannot be tolerated, then a knowledgeable operator becomes an integral factor in safe boiler operation. Continuous attendance by a fully trained operator means that such an operator is continuously in the area of the boiler or boiler control room to immediately observe and respond to any alarm or adverse condition. This operator is also available to perform routine (walk down) inspections of the boiler and observe instrumentation. Protective devices are provided as backup to operator action when the operator cannot respond adequately or when continued operation should not be permitted. The attendance of an operator does not guarantee the avoidance of an emergency shutdown. However, an operator may avert an emergency by reacting to abnormal operating conditions quickly.

3.1.2 Training

Operator effectiveness is largely dependent on training which includes on-the-job experience. The extent and depth of training are related to the complexity of the boiler and to the process served. Sufficient general knowledge is necessary to understand the impact of emergency actions on the boiler and the effect on process. Operators that have been trained to recognize abnormal operating trends are more likely to initiate corrective action before an emergency develops. Trained operators also have the confidence to promptly implement emergency actions based on knowledge of abnormal operating factors and potential outcomes. Periodic retraining may be needed to remind operators of proper responses to infrequently occurring events (emergencies). The National Board recommends periodic retraining, because after operating a boiler for several months with no unplanned (abnormal or emergency) events, an operator may respond slowly or incorrectly to an emergency.[6]

Records of training are essential to ensure operators have been adequately trained on all equipment currently in use. Training records should indicate the scope of activity, training material utilized, operators trained and a rating of the training effectiveness. If operators cannot demonstrate an understanding of the training, then additional training or modification of the training program is needed. Emergency drills can improve operator response and confidence to utilize emergency operating procedures.

3.1.3 Inspection, Testing and Maintenance

Reliable and efficient operation of a boiler is dependent on effective maintenance. One manufacturer states, ‘‘The goal of a maintenance program is to maximize power production, availability, safety and quality while minimizing costs...’’[7] Another manufacturer states, ‘‘A good maintenance program is one of the keys to reliability of any steam generator.’’[8] Boilers presenting a low process interruption exposure may be maintained on a ‘‘breakdown’’ basis with exception of primary safety devices (safety valves, fuel combustion controls and low water fuel tripping systems). An inspection program can identify components needing attention prior to failure and permit repair during a planned outage. For boilers important to process, equipment discovered in need of repair during normal operation should be immediately repaired, while the boiler is operating, or put on a priority action list for repair at the next planned or forced outage.

Planning and recording of inspection, testing and maintenance activities is directly related to the complexity of the boiler and the associated process. For boilers operating at 250 psi (1,700 kPa) or less, the annual operating and internal visual inspections required by most jurisdictions for power boilers are sufficient to identify maintenance necessary for continued safe operation of a boiler. Section VII of the ASME Code contains general guidance and checklists for the inspection and maintenance of watertube power boilers. The boiler manufacturer is the best source for specific information on recommended maintenance activities.

3.1.3.1 Welding

Welding of boiler parts in North America is mostly controlled by the jurisdictional authority. The intent is to ensure the welded repair does not adversely affect materials in the boiler and that the repair will restore the repaired area to nearly new condition. To obtain a National Board Repair Certificate of Authorization, a service organization must demonstrate adequate repair procedures, adequate welder skills, and maintain an inspection agreement with a National Board authorized inspection agency. This system of controls generally assures repairs will be satisfactory.

3.1.3.2 Boiler Tubes

Boiler tube thickness is expected to decrease with usage. The rate of thinning is dependent on many factors. Internal thinning can result from acid formation in the feedwater, pitting from oxygen in the feedwater, steam or water erosion or other causes. External thinning can result from:

- erosive or corrosive elements in or formed by combustion of the fuel
- reducing atmosphere in the furnace
- rubbing of boiler parts on tubes
- air leaks in the boiler casing
- condensate discharge from sootblowers

[6] *The National Board of Boiler and Pressure Vessel Inspectors, The Ten Demandments,* NB-100, Rev 4 (pamphlet, Columbus, Ohio: The National Board of Boiler and Pressure Vessel Inspectors, 1992), page 10.
[7] *S.C. Stulz and J.B. Kitto, eds. Steam — Its Generation and Use,* 40th ed. (Barberton, Ohio: The Babcock and Wilcox Company, 1992), page 44-1.
[8] *Joseph G. Singer, ed., Combustion Fossil Power,* 4th ed. (Windsor, Conn.: Combustion Engineering, Inc. 1991), page 23-1.

Ideally, new tube thickness is measured and periodic thickness measurements are taken to establish a wastage rate. The time to replace tubes can then be predicted based on a minimum acceptable tube thickness for the particular boiler application.

A determination of minimum acceptable tube thickness may require agreement of the jurisdictional authority, the manufacturer and the owner. The ASME Code (Sections I and IV), which provides a minimum tube thickness for new boiler construction states that this thickness is intended ''to afford reasonably certain protection of life and property and to provide a margin for deterioration in service so as to give a reasonably long, safe period of usefulness.''

While Section I indicates an allowance for corrosion or erosion should be provided for pipes, drums and headers (part PG-27), no similar mention is made for tubes. Pipes (which may be outside the boiler casing), drums and headers can release much greater energy upon failure than a tube (inside the boiler casing). Tubes are primary heat transfer elements and do not function well as wall thickness is increased. While thickness of pipes, drums and headers may be satisfactorily increased for corrosion and erosion, tubes are expected to thin below the requirement for new construction and may require replacement during the operating life of the boiler (before repair or replacement of pipes, drums or headers becomes necessary).

3.1.3.3 Thick Wall Components

Thick wall components (drums, headers, pipes) are generally several times larger diameter than tubes and, therefore contain several times more energy. A boiler casing cannot be expected to contain the energy released from rupture of a thick walled component. Also, many thick wall components are at least partially external to the casing. Rupture of a thick wall component results in much greater property damage and greater time element exposure for completion of repair than rupture of a tube.

Thick wall components are susceptible to thermal fatigue from transients during start up, shutdown and load swings. Instrumentation to monitor temperatures and care in operation can minimize thermal stresses. Failure to properly relieve new or repair weld stresses, excessive tube rolling, and failure to maintain adequate boiler water level increase the potential for thermal fatigue failure.

Components operating above 900°F (482°C) are subject to creep. Boilers having steam outlet temperatures of 900°F (482°C) will have components experiencing significantly higher temperatures (100°-150°F [55°-85°C]). Creep results in thinning and crack growth. Increasing material thickness increases creep life but also increases potential for thermal fatigue. Additionally, a recent study indicates thick wall components in cyclic service, operating above 950°F (510°C) and having ASME Code allowable imperfections of up to 12-½ percent of wall thickness, might not be conservatively designed. This study suggests limiting imperfections in SA-335 P11 and SA-335 P22 thick wall components to 5 percent of wall, particularly for cyclic service (quarterly or more frequent cycle).[9]

3.1.3.4 Hydrostatic Testing

The quest to maximize boiler performance has led some manufacturers to use high strength steels for thick wall components (drums, headers, pipes). In some cases the selection is made to minimize weight and wall thickness. Reducing wall thickness also improves boiler response time to load demand changes. High strength steels are also necessary for high pressure (utility type) designs. High strength steels, such as SA 515 Grade 70, have a high transition temperature. Applying a hydrostatic test with metal temperature at or below the transition temperature can result in brittle fracture. Follow the boiler manufacturer's guidelines for minimum hydrostatic test temperature. Always conduct any pressure part hydrostatic test at a metal temperature above the transition temperature. A temperature of 70°F (21°C) is a generally accepted minimum temperature to avoid brittle fracture under hydrostatic test. Some high strength steels require a higher temperature (see Section 2.2.5, Hydrostatic Testing). Also, when hydrostatically testing a warm boiler, follow the manufacturer's maximum recommended temperature differential between thick wall component temperature and water temperature. A maximum differential of 100°F (55°C) is frequently recommended.

[9] *Bloom, J.M. and Lee, D.R., Determination of Piping Acceptance Requirements Based on State-of-the-Art Creep Crack Growth Methodology,* Proceedings of the Fifth International Conference on Creep of Materials, Lake Buena Vista, Florida, May 1992.

3.1.4 Water Quality and Steam Purity

Boiler system and downstream equipment or process integrity and reliability are directly impacted by the water treatment program's ability to maintain boiler feedwater, boiler water quality, and steam purity within operating parameters throughout the steam cycle. Failure to control key parameters can result in damage mechanisms which can negatively impact the boiler system and downstream equipment or processes. Water damage mechanisms can decrease efficiency, heat transfer, cause thermal fatigue, corrosion, overheat, shorten the service life of the equipment, and result in equipment breakdown if not effectively managed by the water treatment program.

Steam quality and steam purity requirements are specified by the OEM of the downstream equipment, such as steam turbines. In many cases, the downstream equipment steam purity limits may be more stringent than boiler water quality limits. Note that steam purity, in addition to steam quality, is also affected by the condition of steam drum separation equipment. Poor steam drum separation will cause water and suspended solid impurities to carry over into the steam.

See Appendix D, Water Treatment Programs, for additional information on water treatment programs.

3.2 Loss History

3.2.1 National Board of Boiler and Pressure Vessel Inspectors Data

The National Board has compiled data annually on boiler incidents. [10] One example of this data for watertube and firetube boiler incidents is shown in Table 3.2.1. While not specific to watertube boilers, the data does reveal the two most important incident factors.

Table 3.2.1. Incident Factors Reported to the National Board

Incident Factor	*Power Boilers (over 15 psi [100 kPa] steam)* *Percent*	*Heating Boilers (steam, 15 psi [100 kPa] or less)* *Percent*	*Heating Boilers (water)* *Percent*
Low water cutoff	44	47	39
Operator error or poor maintenance	34	39	45
Improper installation	8	2	2
Burner failure	6	5	3
Faulty design or fabrication	3	1	3
Limit controls	2	3	5
Improper repair	2	1	3
Safety valve	<1	<1	1

This incident data clearly indicates a need for low water protection (Data Sheet 6-12, *Low Water Protection for Boilers*) and operator training and effective inspection, testing and maintenance practices.

3.2.2 FM Loss Data

FM compiles loss statistics based on business serviced. The following statistics do not represent all loss incidents. Many incidents are not reported to FM because the loss amounts are less than insurance deductibles. The data utilized in the following tables is from losses involving high pressure (greater than 15 psi [100 kPa] steam) watertube boilers for the period 1987 through 1992.

While reviewing the data in the following tables, it is important to recognize that comprehensive inspection programs are provided for many industrial and utility boilers. These programs frequently reveal conditions requiring corrective action prior to a loss. The loss data in these tables represents only boilers that do not have inspection programs or defects that could not be detected by inspection programs.

[10] *National Board Bulletin, 1992 Incident Report, Spring 1993, page 2.*

Note: The following data excludes loss data involving fuel combustion controls and furnace explosions or implosions. Loss data on those topics may be found in data sheets on fuel combustion controls.)

Table 3.2.2-1 reveals that over half of all losses involve tubes.

Table 3.2.2-1. 1987–1992 Boiler & Machinery High Pressure Watertube Boiler Losses (excludes Black Liquor Recovery Boilers) by Damaged Part

Damaged Part	*Number of Losses*
Tubes	82
waterwall	17
generating	16
screen	9
economizer	2
circulating	2
superheater	9
not identified	27
Economizer (not tubes)	1
Grate	2
Low water control	2
Welded connection	1
Refractory	2
Other	16
Total known part	106
No data/no report	23
Total	129

Table 3.2.2-2 shows many incidents result from materials being subjected to temperatures exceeding intended limits. The National Board data confirms that very few failures result from safety valves not limiting boiler pressure to intended limits. The excessive temperature may result from internal deposits limiting heat transfer from boiler material to water or steam. To overcome the effect of deposits, heat input is typically increased to maintain the level of steam output.

It should not be inferred from this table that low water protection systems have had a very minor impact on FM loss experience with watertube boilers. In many cases, the kind of failure reported as a result of a failed low water protection system is rupture, distortion (bulging, sagging, etc.), or overheating. This is substantiated by the data presented in Table 3.2.2.-4.

Table 3.2.2-2. Watertube Boiler Losses by Kind of Failure

Kind of Failure	*Number of Losses*
Rupture	43
Distortion (bulging, sagging, etc.)	20
Overheating	10
Low water control failed to operate	2
Deterioration	3
Other	30
Total known kind of failure	108
No data/no report	21
Total	129

Table 3.2.2.-3 demonstrates the need to avoid abnormal temperatures. These temperatures may result from failure to maintain boiler feedwater and boiler water quality (deposits lead to overheating), maintain proper water level (dry firing) or maintain metal temperatures within design limits (drums, superheater, reheater headers, tubes).

Table 3.2.2-3. Watertube Boiler Losses by Direct Cause

Direct Cause	*Number of Losses*
Abnormal temperature	58
Abnormal pressure	4
Freezing	1
Deterioration of equipment	5
Mechanical defect	4
Corrosion/erosion	11
Fatigue/stress	16
Other	11
Total known direct cause	110
No data/no report	19
Total	129

Table 3.2.2-4 demonstrates the need to provide and maintain appropriate safety controls and protective devices.

Table 3.2.2-4. Watertube Boiler Losses by Subcause

Subcause	*Number of Losses*
Inadequate/needed protection, safety device or control	35
protective device needed	2
control/safety device bypassed	6
low water control failure	14
safety/control device failed	6
low water control needed	4
inadequate control/safety device	3
Foreign substance	18
Impingement	7
Deterioration	11
Freezing	2
Accelerated wear, tear	3
Other	30
Total known subcause	106
No data/no report	23
Total	129

Table 3.2.2-5 shows that 82 percent of losses with known contributing causes involve human element factors. Improved operator training in particular and improved maintenance could significantly reduce loss amounts.

Table 3.2.2-5. Watertube Boiler Losses by Contributing Cause

Contributing Cause	*Number of Losses*
Improper operation	30
lack of operator attention	11
lack of training/supervision	7
accidental misoperation	1
operating in poor condition	5
operating in known poor condition	5
malicious misoperation	1
Maintenance	37
recommended not completed	5
testing/inspection not performed	14
routine maintenance not performed	18
Manufacturing defect	8
Non-human element factors	7
Total known contributing causes	82
No data/no report	47
Total	129

Table 3.2.2-6 highlights the need to control boiler water chemistry to prevent corrosion and under-deposit corrosion. It also emphasizes maintaining steam purity to safeguard downstream equipment and the importance of preventing contamination from processes and cooling water systems.

Table 3.2.2-6. Boiler Water Treatment Losses by Damage Mechanism (2009 - 2024), Indexed to 2024 Values

Subcause	*Number of Losses*
Contamination	5
Dry fire	4
Carryover - deposition/erosion/corrosion	4
Corrosion/under deposit corrosion	3
Scaling	3
Other tube leaks	2
Improper chemical dosing	1
Carryover - water induction	1
Total	23

3.3 Illustrative Losses

3.3.1 Operator Training

Two losses resulted from lack of operator training.

3.3.1.1 Low Water Condition Results in Tube Damage

One loss involved a facility with a three-drum-type, 60,000 lb/hr (27,000 kg/hr) watertube boiler supplying all process steam demands. The 13-year old boiler is equipped with three separate devices for feedwater control, high level alarm and low water tripping. All three devices are on the same steam and water connections to the boiler. The boiler is fired with wood waste on a grate.

A relief boiler operator, who had not operated the boiler for several years, advised the returning operator that high drum level problems had occurred during the previous three hours. The operator noted the boiler feed pump was off and water was leaking from a gasketed connection in the feedwater line at the steam drum.

The lead boiler operator was called. Water level was at ¾ of the gage glass. The boiler was secured, filled, and the gasket replaced in the leaking connection. The operator continued to have difficulty maintaining water level and maintaining boiler firing. Further investigation revealed water running from the sand hoppers.

After securing the boiler, it was discovered that many of the water wall tubes and all generating tubes were distorted or sagged. Review of the flue gas temperature chart record indicated a temperature rise one and one-half hours after the relief operator started and a second, off the chart rise, one-half hour after the operator returned. The piping to the water level control and safety devices was found plugged. The relief operator had mistaken the empty gage glass as being full.

This loss was exacerbated by a local repair contractor plugging, re-rolling and seal welding tubes with no success for six days. A second repair contractor determined tubes needed to be replaced. Tube holes were now oversized and out of round from the initial repair efforts. This necessitated replacing the drum shells and the tubes.

The mill is now providing refresher training to all personnel who may operate the boiler. It is intended that all safety controls will be tested and maintained. Additionally, a second, independent low water tripping device, two new feedwater pumps and a dual element feedwater control have been provided.

3.3.1.2 Tube Ruptures Caused by Erosion and Poor Soot Blowing Procedures

The second loss involved a mill with three similar pulverized coal-fired, four-drum (36 years old at time), Sterling-type watertube boilers that power two turbine generators and supply process steam. The boilers each provide 250,000 lb/hr (113,000 kg/hr), 750°F (400°C) steam at 650 psi (4,500 kPa). The boilers have flat stud tube walls backed with refractory, followed with insulation (asbestos) and an outer cold casing. The boiler manufacturer inspected the entire No. 3 boiler six months prior to this incident and found no indications in the affected area. The mill also has two gas or oil fired package type boilers.

At the time of the incident, boiler no. 4 was dismantled for inspection. Boiler No. 1 tripped off, probably due to operator error. With the reduced steam supply, automatic load shedding began. Shedding was not quick enough to prevent tripping of the two steam turbines on low steam pressure. With the sudden loss of steam demand, safety valves began to lift and the three remaining boilers tripped on low water or furnace pressure. At this time the casing of No. 3 boiler was breached. The boiler house was evacuated because asbestos was expected to have been released.

Two tubes ruptured in the last row of furnace screen tubes, near the middle of the row. One tube remained in place. The other split. One end swung up into the boiler, damaging seven superheater tubes and twelve generating tubes. The sudden release of steam from two tubes resulted in refractory damage and bulging of the casing to varying degrees in seventeen areas. Repair time was increased due to asbestos abatement.

Investigation indicated tube erosion in the row of tubes containing the two ruptures. The sudden upsets in steam pressure resulted in rupture of the thinned tubes. Further investigation revealed operators had deviated from established soot blowing practices and the outside sootblower consultant had not advised supervision of the deviation nor the tube erosion. The plant has re-established soot blowing procedures and has improved communications with another soot blower consultant.

3.3.1.3 Thick Wall Component Evaluation and Repair

This loss involved a 1967 vintage boiler (25 years old at time) at a utility generating station. It produces steam 2,584,000 lb/hr (11,700,000 kg/hr) with superheater outlet conditions of 1000°F (540°C) at 3653 psi (25,000 kPa). The unit is base loaded. Shutdown inspections are conducted at six month intervals, including thickness readings at known high wastage areas and a hydrostatic test. In early 1987 a study was conducted that included header inspections, replications and nondestructive examinations (exact details of testing not available).

Prior to the incident the unit was operating at 90 percent capacity when an alarm sounded for abnormal convection pass pressure and a roaring noise, like a safety valve lifting, were noted. In two minutes output dropped to 73 percent capacity and the operator manually tripped the unit. At this time an operator for an adjacent unit called the control room to report smoke and fly ash coming from the boiler penthouse area.

Investigation revealed attachment of a 3-¼-inch inspection plug in one end of the superheater outlet header had failed. The plug penetrated the penthouse wall and was found on a nearby floor grating. Escaping steam bulged two penthouse walls outward and an area of the penthouse floor was buckled. Metallurgical examination of the plug indicated the failure resulted from creep. The utility is having all similar inspection plugs examined by dye penetrant, magnetic particle and having replications made.

This incident illustrates the need to carefully examine all welds on high temperature headers on older boilers having P11 or P22 headers for signs of creep.

3.3.2 Operation

Boiler feedwater contamination can quickly result in serious boiler damage. Loss factors in the past year alone include heat exchanger leakage (indirect type exchanger), process backflow (direct steam heating), backflow of acid from hydrogen cation treatment systems and improper use of cross connections between process and condensate lines (particularly common in pulp and paper mills).

Three losses involved machinery operation.

3.3.2.1 Lack of Steam Flow through Superheater Results in Damaged Tubes

The first involved a 1025 psi (7,000 kPa), 325,000 lb/hr (150,000 kg/hr) watertube boiler. It provides steam at 520 psi (3,600 kPa) for electric generation 10 months of the year at a high rise apartment and shopping center complex. The superheater screen tubes are SA-213 Grade T11 and the rest of the superheater tubes are SA-210 Grade A. This 25-year old oil fired boiler was internally inspected three month prior with no apparent signs of overheating or deposits. The boiler had been operating for two months after the internal inspection when an operator noted excessive vibration of the forced draft fan. While the boiler was being taken off line for investigation, water vapor was observed coming from the exhaust stack. Investigation revealed several blistered, split and deformed superheater tubes.

Further investigation by the boiler manufacturer revealed a total of 23 superheater tubes needing replacement. These tubes were variously blistered, split, thinned, badly bowed or had lost material strength. Internal fiber optic inspection revealed only minor pitting and deposits.

Tube overheating was attributed to insufficient cooling steam flow during start-up and during standby. Operating procedures had earlier been modified due to similar problems in other boilers at the facility. A steam outlet temperature monitor is not provided.

Planned corrective action includes installation of thermocouples to permit operators to monitor and regulate superheater steam temperature (by maintaining a flow through the superheater) and replacing the SA-210 Grade A tubes with SA-213 Grade T11 tubes. This incident illustrates the necessity of maintaining cooling steam flow through a superheater and the difficulty operators can encounter due to limited instrumentation on many boilers.

3.3.2.2 Waste Heat Boiler Tubes Crack

A second loss involved a watertube waste heat boiler at an agricultural fertilizer plant. It provides superheated steam at 762°F (400°C) and 635 psi (4,400 kPa) to a steam turbine driving an air blower and process steam. The superheater has one row of a type 304 stainless steel tubes, the remainder are a 1-¼ Cr-½ Mo material. Start-up of this unit was one year prior to the incident. The unit was initially operated for 7 to 10 days prior to having all instrumentation in operation. Two months after start-up, steam turbine performance noticeably deteriorated. Lifted cover inspection revealed white deposit on the rotor. The source was assumed to be boiler carryover. The only action taken was water washing of the turbine. Eight months after start-up, steam analyzers were installed and intermittent carryover was detected. Ten months after start-up, the boiler steam drum was opened and steam separation equipment was found out of place due to a weld failure. This was assumed to be the cause of the carryover. The separation equipment was restored but no washing of the boiler and steam piping (to passivate the carryover) was done.

Thirteen months after start-up, high moisture was detected in the process stream. Adjustments did not correct the condition. Two weeks after detection, the unit was shut down for corrective action. Inspection revealed seven of 22 stainless steel superheater tubes had cracks in the ‘‘U’’ bends. Cracking was attributed to the carryover. Deposits containing compounds of sodium, sulfur, chlorine and calcium were found. Chloride compounds are known to cause stress corrosion cracking in stainless steels. A metallurgical report on the bends indicated the cracking was due to stress corrosion with large variation in tube bend wall thickness and residual stresses in the bends contributing to the cracking. Cracking initiated on the inside surface where carryover contaminants could concentrate and the crack propagation was slow.

The seven cracked tubes were bypassed to expedite return to production. Repair will require replacement of these seven tubes and the two sets (14 tubes) of 1-¼ Cr, ½ Mo tubes behind them. The plant is considering replacing the entire superheater (shorter outage than replacing tubes in existing superheater) and using annealed forged ‘‘U’’ bends in the stainless steel tubes rather than cold formed bends.

This incident shows the importance of not operating a boiler until all instrumentation is operational, to determine the source of carryover and correct the defect upon discovery. It also demonstrates the value of continuous steam purity monitoring. The cost of continuous steam purity monitoring would be less than one tenth the value of lost production in this incident.

3.3.2.3 Lack of Water Testing in Tube Leaks Caused by Contamination

A third loss involved two gas fired, 750 psi (5,000 kPa), 150,000 lb/hr (68,000 kg/hr) 1976 vintage watertube boilers (16 years old at time). They supply process steam at a chemical process plant. Numerous heat exchangers are used in the process with condensate returned to the boiler feedwater system.

On the day of the incident a supervisor noted fuel gas, feedwater and combustion air flows increasing for both boilers. An immediate check was made of process piping and vessels for a steam leak. Upon return to the boiler room, the supervisor noted water leakage under one boiler and water vapor issuing from both boiler stacks. Attempts to keep boilers operating were not successful, because leakage continued to increase. One boiler was shut down one and one-fourth hours after the leakage increased. The other was shut down about 15 minutes later.

Inspection revealed all boiler tubes were loose in the drums. There were cracks in two superheater tubes, and three mud drum ligament cracks were found in one boiler. All tubes were loose in the mud drum of the other boiler. Tube seat leakage and ligament cracks had been a problem in the past. Investigation at this time included tests of the feedwater which revealed traces of the product and isopropyl alcohol. Testing of process heat exchangers revealed pin hole leaks. The contamination of the condensate by the process stream is believed to have caused foaming and carryover in both boilers. The carryover deposits could have caused overheating and cracking of the two superheater tubes. Foaming may have interfered with the boiler water level instruments and may have led to dry firing.

The plant diverted condensate from the leaking heat exchangers to the sewer until conductivity probes could be installed in the condensate return lines. Frequency of boiler water testing has been increased to daily. Subsequent to this incident, one boiler was completely retubed.

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Data Sheet 6-6, *Boiler-Furnace Implosions*
Data Sheet 6-7, *Fluidized Bed Boilers*
Data Sheet 6-12, *Low-Water Protection*
Data Sheet 6-13, *Waste Fuel-Fired Facilities*
Data Sheet 6-14, *Heat Recovery Boilers*
Data Sheet 6-21, *Chemical Recovery Boilers*
Data Sheet 7-72, *Reformer and Cracking Furnaces*.
Data Sheet 7-99, *Heat Transfer by Organic and Synthetic Fluids*
Data Sheet 7-111G, *Ammonia and Ammonia Derivatives*
Data Sheet 9-0, *Asset Integrity*
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APPENDIX A GLOSSARY OF TERMS

This document does not have any defined terms.

APPENDIX B DOCUMENT REVISION HISTORY

The purpose of this appendix is to capture the changes that were made to this document each time it was published. Please note that section numbers refer specifically to those in the version published on the date shown (i.e., the section numbers are not always the same from version to version).

April 2025. Interim revision. Guidance on establishing and implementing a boiler water treatment program, including guidance on boiler feedwater quality, boiler water quality and steam purity was completely revised and improved. Select editorial changes were also made for additional clarity.

October 2024. Interim revision. Minor editorial changes were made.

January 2022. Interim revision. Minor editorial changes were made.

January 2021. Interim revision. Updated contingency planning and sparing guidance.

May 2010. Minor editorial changes were done for this revision.

January 2001. Recommendations and support addressing boiler tube thinning and replacement are revised. The revisions take into account changes to the allowable stresses for boiler tubes that appeared in the 1999 Addenda to the ASME Boiler & Pressure Vessel Code.

September 2000. Document was reorganized to provide a consistent format.

June 1995. Major update and re-write.

APPENDIX C SUPPLEMENTAL INFORMATION

C.1 Essential Elements of an Inspection, Testing and Maintenance Program

This section lists key elements of a watertube boiler inspection, testing and maintenance program as part of the boiler's asset integrity program. Follow recognized and generally accepted good engineering practices, original equipment manufacturer, and industry guidelines. Section VII Recommended Guidelines for the Care of Power Boilers, ASME Code, is a resource on operation, inspection, testing and maintenance. The needs of the individual boiler based on the service conditions must be reviewed to develop a viable asset integrity program. (Items marked * are more applicable to field erected industrial or utility boilers.):

1. Annually perform a thorough inspection of the fireside and waterside surfaces of pressure parts. The inspection interval may be subject to local jurisdictional and/or regulatory requirements.

2. Annually perform a thorough inspection of the boiler while it is operating. This is commonly termed the annual ''operating'' or ''external'' inspection. The interval may be extended up to 24 months with agreement of the FM Global consultant, the jurisdiction (if any) and the owner. See the conditions stated in ''1'' above for extending the interval.

3. Develop and implement a well defined inspection plan that includes ultrasonic examination of predetermined boiler pressure parts subject to rapid thinning. Parts such as screen tubes, superheater tube bends, tubes adjacent to soot blower cavities, air port opening tubes and lower furnace wall tubes need to

be examined. Develop the frequency and extent of ultrasonic examination from operating experience for each boiler. Carefully record all thickness readings for future reference and trend analysis. See Section C.5, Nondestructive Examination, for additional guidance.

4. All alterations or repairs follow the requirements of the NBIC, current edition.

5. Carefully remove slag from boiler passes. Blunt ended rods may be used. Exercise caution when rodding to avoid pressure part damage. Water washing of fireside surfaces may be done by means of soot blowers in a shutdown unit if done strictly in accordance with the boiler manufacturer's recommended procedure.

6. In the soot blower maintenance program, include blower alignment checks, full lance insertion and retraction, proper rotation, smooth movement of swivel tube in both transverse and rotational direction with no whipping or erratic movement, correct blowing pressure (pressure at each blower should drop a specific amount each time poppet valve opens), poppet valve opening fully, no steam leakage at sootblower head gland, inspection of the condensate removal system and verification of proper indexing during the operating cycle. (Note: Indexing causes the soot blower to shift slightly before rotation is resumed during the retraction cycle or at the end of the retraction cycle. This prevents steam and any condensate from impinging on the same tube area on each blow cycle.)

7. Inspect, test and maintain the boiler feedwater and boiler water systems as part of the boiler's water treatment program. An effective water treatment program will minimize internal corrosion, scale formation, carryover and sludge deposits. Follow the boiler manufacturer's recommendations.

8. Maintain boiler steam purity and steam quality as required by the OEMs of downstream equipment.

9. Inspect, test and verify the fuel combustion control and safety system is fully operable on a scheduled basis. Establish test limits and reporting procedures.

10. Complete a hydrostatic test after each planned inspection with the minimum test pressure being the operating pressure. Determine the minimum temperature of boiler pressure part materials to be above the material transition temperature during the test to avoid brittle fracture.

11. Examine attachment welds and other areas prone to cracking by an appropriate nondestructive examination method (radiography may be required for attachment welds to tubes).

121. Visually inspect metal spray coated furnace walls for evidence of spalling or bond failure. Take action necessary to restore coating. Visually inspect furnace wall weld overlay areas for evidence of cracking. If indications are discovered, use liquid penetrant testing to determine extent of corrective action needed.

13. When replacing complete lower furnace walls in waste or refuse fired boilers having plain carbon steel tubes, consider using composite tubes which are more corrosion resistant.

14. The extent and rate of waterside deposition on tubes in high heat release areas needs to be determined and monitored. This may be done by analyzing deposits in tubes removed for other reasons or purposely removing an 18 to 24 inch (460 to 610 mm) section from a high heat transfer area. Corrective action necessary is based on analysis results. Chordal thermocouples may also be used to indicate waterside deposition. At a given steaming rate, the tube temperature will increase as waterside deposition occurs.

15. Consult the boiler manufacturer for any bulletins or technical information letters regarding recommended maintenance, alterations, or recommended change in operating practice.

C.2 Test and Examination Methods

Many methods of testing or examination may be applied during the service life of watertube boilers. The commonly used nondestructive examination (NDE) methods are:

1. Visual Testing (VT): used to locate obvious indications

2. Ultrasonic Testing (UT): used to determine metal thickness and locate or evaluate subsurface or otherwise hidden flaws and defects in base metals and weldments

3. Radiographic Testing (RT): used to determine the quality of pressure part welds

4. Magnetic Particle Testing (MT): used to locate surface defects in tubes, drums, headers or welds made of magnetic materials

5. Liquid Penetrant Testing (PT): used to find surface defects in tubes, drums, headers or welds

C.2.1 Visual Testing (VT)

Visual Testing is the most common and cost-effective method of initial inspection. The method is most effective when used with a knowledge of the construction, operation and previously identified problem areas of the specific boiler or boiler type. Some of this knowledge can be obtained from reference materials. Much of it must be learned by experience. VT is commonly used to locate gross deficiencies and to identify areas requiring a more sophisticated method of testing.

C.2.2 Ultrasonic Testing (UT)

Because of the corrosive nature of some fuel combustion products and because fuel ash is erosive, it is important to set up a good UT program. UT provides a history of tube wastage and provides trending information for maintenance purposes. It must be understood that UT is not a substitute for thorough visual inspection nor can UT assure that all possible thin tubes have been discovered. Inspection by UT is complimentary to visual inspection.

Thickness measurements fall into two general categories: set locations (predetermined) and random locations. The set locations are measured during each test period, at the exact location, during annual outages. (See Section C.2.2.1.) Random locations are determined during the annual inspection. For instance, a particular area around a primary air port may be deteriorated and require detailed thickness readings. Include the following in a tube thickness mapping system:

1. previously discovered metal wastage patterns (Patterns need to be determined for each boiler.)

2. testing in the furnace (Locations depend on type of hearth, method of firing, size of boiler and fuel characteristics.)

3. superheater testing (Locations depend on design pressure, temperature, and configuration of the superheater.)

4. generating tube bank testing (Locations depend on boiler bank type, flue gas velocity and soot blower location.)

5. economizer testing (Locations depend on configuration, exit temperature, feedwater temperature and feedwater treatment.)

C.2.2.1 UT Determination of General Furnace Wastage

For the furnace, number each tube on each wall from left to right when facing the wall from the inside of the furnace. Number screen tubes, superheater tubes, boiler bank tubes and economizer tubes left to right looking in the direction of the gas stream and number the rows of tubes from front to back.

Benchmarks are used (air ports or welded attachment) to mark an exact elevation for a series of readings. For example, for the left side wall elevation A, note one benchmark on Tube 1 and one on Tube n. A chalk line strung between the benchmarks will accurately define the test locations. These locations can then be found by using the same benchmarks for future tests.

It is recommended that initial measurements be taken around the entire accessible surface of furnace wall tubes to locate areas of accelerated thinning. These areas are generally near the crotch of tangent tubes or membrane bar. The locations of readings taken around a tube at a given elevation need to be identified for future comparison.

For membrane wall construction, measurements at a minimum of three positions are needed, on the face of the tube and at positions close to the membrane filler bars on either side of the tube. This technique is sometimes referred to as ‘‘three-point examination.’’ Use of this technique is important as thinning near the membrane filler bars is more rapid than on the face or crown.

A furnace wall test location may be labeled: A-LEFT-62-0-0.165. This means the 62nd tube in the left wall, at elevation A measured at position 0 (face) reads 0.165 in. wall thickness. A boiler bank tube test location may be labeled: F-R10-24-180-0.165. This means at elevation F in Row 10, the 24th tube from the left at position 180 (opposite from face), the measurement is 0.165 in. wall thickness.

The mapped ultrasonic examination program needs to be supplemented with a random examination of areas that are not part of the scheduled program. The selection of random locations is based on previous findings and conditions observed during the annual visual examination. As an example, some boilers show corrosion of tube metal on the cold side of the tubes. If there are casing bulges, testing is warranted in the area. Casing and insulation must be removed to make the inspection. Boilers not having gas tight water wall construction are more susceptible to cold side corrosion.

Examination is needed in areas where erosion or corrosion has occurred (e.g., from soot blowers) or where severe stud loss is evident, such as above, below and on the side of primary air ports. Corrosion on the cold side of tubes has been found in the wind box.

A good reference for a tube thickness measurement program is TAPPI TIS 0402-18 Guidelines for Nondestructive Thickness Measurement of Black Liquor Recovery Boilers (1993).

C.2.3 Radiographic Testing (RT)

Radiographic Testing (RT) is recommended for all pressure part butt welds made in the shop or field during erection of new boilers and during repair or alteration of existing boilers that are essential to production. RT is also useful in detecting internal stress-assisted corrosion cracking at attachment welds (for wind boxes, spacer and tie bars, floor seals etc).

C.2.4 Magnetic Particle Testing (MT)

Magnetic Particle Testing (MT) is recommended in the following areas (wet fluorescent magnetic particle testing [WFMT] is preferred):

1. pressure retaining welds on drums and headers
2. steam and water (mud) drum ligaments
3. on welds and at openings in headers
4. attachment points of structural supports such as buckstays, burner ports and floor beams

C.2.5 Liquid Penetrant Testing (PT)

Liquid Penetrant Testing (PT) is recommended in the following areas:

1. tubes (Fatigue can lead to circumferential indications and frequently show up in tubes within a distance of 5 in. [125 mm] from drums and headers. Indications may be found in screen tubes and in composite tube furnace wall openings.)
2. pressure part welds
3. attachment welds such as superheater tie clips, flat studs and pin studs
4. steam and mud drum ligaments
5. bent tube sections at furnace and boiler wall openings

For additional information on NDE methods, refer to ASME Code, Section I and Section V. Reference to TAPPI, *Technical Information Papers (TIP),* may also be helpful. Three that are related to NDE are TIP 0402-12, *Guidelines to Assure Quality Radiography of Boiler Tubes and Pipe Weldments in the Paper Industry;* TIP 0402-13, *Guidelines for Specification and Inspection of Electric Resistance Welded (ERW) and Seamless Boiler Tube for Critical and Non-critical Service;* and TIP 0402-18, *Guidelines for Nondestructive Thickness Measurement of Black Liquor Recovery Boilers.*

C.3 Repairs

All pressure part repairs are to be made in accordance with the *NBIC,* except where more stringent recommendations have been made. The Electric Power Research Institute (EPRI) Manual for Investigation and Correction of Boiler Tube Failures is a good tube repair reference for large field erected boilers. Similarly, the American Forest Products Association (AFPA) *Recovery Boiler Reference Manual,* Volume II, Chapters 3, *Maintenance and Repair Analysis* and 4, *Repair Guidelines and Practices,* is a good reference for intermediate size field-erected boiler furnace wall tube repair. This manual indicates tube repairs should be made with full circumferential welds. The only exception is welded tangent tube furnace wall construction which may require a window weld repair.

Prompt action on all needed repairs is essential for continued safe operation of the boiler. Records of all repairs made on boilers and any equipment or auxiliaries affecting the operation of boilers need to be kept. A record of any deferred repair, with the reason for the delay, needs to be maintained.

Any leaks, however small, need to be traced to the source. The proper repair, not only to stop the leak but to prevent a recurrence, needs to be completed promptly.

If pitting in a closely grouped or aligned formation is deep enough to affect the pressure retaining capability of the material, the affected area needs to be repaired and approved by an authorized inspector. Isolated pitting not affecting the pressure retaining capability of the material may be controlled by cleaning the affected area carefully (e.g., grit blast) and applying some form of protective coating.

Straightening of tubes sufficiently warped to prevent proper cleaning or internal inspection for soundness and cleanliness is not advisable. Such tubes should be replaced.

A water tube with a series of closely connected bulges should be replaced. Setting back bulges on water tubes is not recommended. Bulges are an indication of overheating from deposits forming on the waterside or flow restriction in the tubes. The boiler may need to be cleaned and the cause of the deposits or flow restriction determined and corrected.

The internal deposit composition and failure mode should be determined for any piece of tube that requires replacement. The information gained can be used to revise the boiler water treatment program or modify boiler operation to avoid a recurrence.

APPENDIX D WATER TREATMENT PROGRAMS

D.1 Water Treatment Program Scope

Effective water treatment programs maintain boiler feedwater (external to the boiler, such as raw/make up water supply/condensate), boiler water (internal to the boiler) quality, and steam purity within parameters as part of the boiler’s asset integrity program. Without proper water treatment chemistry, deficiencies can range from rupture of a single tube to failure of the entire boiler, damage to boiler water system and damage to downstream equipment or processes. The water treatment program can identify and reduce the impact of the potential damage mechanisms on the equipment in the boiler system. Boiler systems include condensate systems, feedwater heaters/tanks, deaerators, economizers, superheaters and reheaters. The downstream equipment or process can include steam turbines, power and process piping, and process/production equipment.

To maintain boiler integrity and performance and to provide steam of suitable turbine or process purity, boiler feedwater must be purified and chemically conditioned. The amount and nature of feedwater impurities that can be accommodated depend on boiler operating pressure, boiler design, steam purity requirements, type of boiler water internal treatment, blowdown rate and whether the feedwater is used for steam attemperation (desuperheating). Feedwater chemistry parameters to be controlled include dissolved solids, pH, dissolved oxygen, hardness, suspended solids, total organic carbon (TOC), oil, chlorides, sulfides, and alkalinity. The extent of a boiler’s internal and external water treatment requirements will depend upon multiple factors, including the boiler’s operating pressure.

Section D.4 of this appendix provides additional detail on typical equipment configurations and requirements for the various operating pressure ranges.

In some cases, the end use of process steam or hot water will place restrictions or additional requirements on water treatment programs. For example, Hydrazine, a common oxygen scavenger, is typically not allowed for use in food industry applications due to its toxicity and risk of cross contamination.

Utilize a qualified water treatment consultant and/or qualified in-house personnel to manage efficacy of the water treatment program. Maintaining the boiler water treatment program for the intended service has the following benefits:

1. Maintain energy efficiency
2. Improve heat transfer and service life of boiler tubes
3. Prevent tube damage or failure and damage to boiler water supply system and/or downstream equipment or processes

D.2 Water Treatment Processes

The water treatment program involves several key external and internal treatment processes to ensure the boiler feedwater quality is suitable for boiler operation/service conditions. Depending on the boiler type, operating pressure and water quality/steam purity requirements, these processes may include some or all of the following:

A. For external treatment processes:

1. Screening, Clarification, Filtration and Ultrafiltration: Removes suspended solids, particulates, and other impurities by passing water through filters.

2. Ion Exchange – Water Softening: Removes calcium, magnesium and other metal cations that cause hard water and scale buildup. This process uses ion exchange resins to replace calcium, magnesium, and other metal cations in the water with sodium ions, effectively softening the water and preventing scale formation.

3. Membrane Processes: These processes include reverse osmosis (RO) and nanofiltration (NF), which use semi-permeable membranes to remove dissolved solids, salts and other impurities from the water.

4. Ion Exchange – Demineralization: For boiler water requiring the highest purity, demineralization removes positively charged cations and negatively charged anions from the water. A typical arrangement may include separate cation and anion resin vessels followed by a mixed bed vessel containing both cation and anion resins. As water passes through the vessels, cations are exchanged with hydrogen ions, and anions are exchanged with hydroxide ions.

5. Deaeration/Degasification: This process removes dissolved gases like oxygen and carbon dioxide using steam to heat the water and reduce the solubility of entrained gases, while simultaneously increasing the surface area of the water with cascading trays or spray nozzles. Oxygen and carbon dioxide can cause corrosion in the boiler system, so their removal is crucial.

B. For internal treatment processes:

1. Chemical Dosing: Specific chemicals are added to the boiler water to control pH, prevent scale, prevent corrosion, and remove or control oxygen. Common chemicals include oxygen scavengers, pH adjusters, pH buffering agents, corrosion inhibitors, and scale inhibitors. The following list provides general description of the common types of boiler water treatment programs:

a. **Caustic Treatment (CT):** Caustic NaOH is added to the boiler drum to provide solid alkali-based pH. It is often combined with feedwater treatment programs such as oxygen scavenging and with volatile chemicals like ammonia and amines, used for feedwater pH control and corrosion inhibition.

b. Phosphate Treatment (PT): Similar to caustic treatment, sodium phosphates [typically Trisodium (Na_3PO_4) and/or Disodium ($NaHPO_4$) Phosphate] are added to the boiler drum to provide solid alkali-based pH; small additions of caustic NaOH may also be used in this treatment. Phosphate treatments are effective at precipitating certain impurities such as calcium and magnesium out of the boiler water so they can be removed by bottom blow down. They are often combined with feedwater treatment programs such as oxygen scavenging and with volatile chemicals like ammonia and amines, used for feedwater pH control and corrosion inhibition. Multiple variations of phosphate treatments are available, including Precipitation, Coordinated, Congruent and Equilibrium. Some water treatment programs use chelants to perform a similar function as phosphates.

c. All Volatile Treatment (AVT): AVT covers several types of feedwater treatments in which no chemicals are added to the boiler drum during normal operation (AVT(R), AVT(O), and OT). AVT treatments are most commonly seen in the higher operating pressure ranges greater than 1500 psi (10,300 kPa) and where feedwater is externally treated to the highest purity (i.e. lowest conductivity).

i. Reducing – AVT (R) - Uses ammonia (or an amine of lower volatility than ammonia) and a reducing agent (usually hydrazine or carbohydrazide) to treat boiler feedwater for pH and corrosion inhibition. This AVT option is the best and, typically, the only option for mixed metallurgy systems that contain both copper and ferrous heat exchangers.

ii. Oxidizing – AVT (O) - Like AVT (R), AVT (O) uses ammonia (or an amine of lower volatility than ammonia) to treat boiler feedwater for pH and corrosion inhibition. However, with AVT (O) no reducing agent is used. Instead, AVT (O) targets a higher DO_2 level (typically 5-30 ppb) by relying on a limited amount of air in leakage in the condenser. This treatment type promotes development of a protective magnetite layer on ferrous surfaces.

iii. Oxygenated Treatment (OT) - Like AVT(O), OT uses ammonia (or an amine of lower volatility than ammonia) to treat boiler feedwater for pH and corrosion inhibition. With OT, however, additional oxygen is injected into the feedwater, targeting DO_2 levels in the 50-200 ppb range, depending on boiler configuration. This treatment type promotes development of a protective hematite layer on ferrous surfaces. Hematite is generally stronger and more stable than magnetite that can lead to lower levels of iron migration and downstream deposition.

d. Oxygen Scavengers: Oxygen scavengers such as hydrazine or carbohydrazide are used to reduce dissolved oxygen in feedwater and boiler water to minimize corrosion potential. Oxygen scavengers are typically used in combination with CT, PT, or AVT(R).

e. Supplemental Treatments: Other supplemental chemicals are sometimes combined with the above listed treatments, based upon the unit-specific treatment program. .Supplemental Treatments: Other supplemental chemicals are sometimes combined with the above listed treatments, based upon the unit-specific treatment program.

i. Filming amines - These chemicals form a protective film on metal surfaces, preventing corrosion by creating a barrier between the metal and the water. They are most effective in lower temperature applications such as condensate piping.

ii. Dispersants and scale inhibitors - Chemicals such as polymers are used to help prevent the formation of scale and deposits by dispersing suspended solids and keeping them in solution.

Note: Combined treatment generally refers to water treatment programs that combine aspects of multiple treatment programs based on unit-specific requirements. For example, ammonia, hydrazine and polymer treatments are injected into boiler feedwater, while trisodium phosphate is injected into the steam drum.

C. Blowdown is used to continuously or periodically remove a portion of the boiler water to control the concentration of impurities. The two types of blowdown are surface and bottom. Surface (continuous) blowdown removes water containing dissolved solids from the mid-section of the steam drum. Bottom blowdown (blow off) removes sediment and water containing suspended solids from the bottom of the steam drum, or (in a two drum configuration) from the mud (lower water) drum. Some types of chemical treatments cause certain impurities such as calcium and magnesium to precipitate out of the boiler water where they can be effectively blown down. Steam drum water samples are commonly taken from the surface (continuous) blowdown.

D. Regular testing and monitoring of the boiler water chemistry are essential to ensure it remains within desired parameters. This testing and monitoring includes, but is not limited to, checking pH levels, conductivity and levels of dissolved oxygen. The extent of parameters tested and the frequency of testing required depends on the boiler application. For those systems equipped with continuous online monitoring, alarms should be tied into the unit's control system. Instrumentation should be maintained and calibrated as part of the site's asset integrity program.

E. Each of these processes can play a key role in maintaining boiler feedwater quality and preventing damage mechanisms like scaling, corrosion and fouling. A qualified water treatment consultant and/or qualified in-house personnel will design a unit-specific water treatment program based on factors such as the properties of the raw water supply, boiler design, and the presence of mixed metallurgy (copper) in the condensate/feedwater system. It will also consider operating conditions such as cyclic operation. Note that boilers of higher operating pressures with downstream equipment or processes such as steam turbines will typically have more complex and rigorous water treatment programs.

D.3 Damage Mechanisms

Water treatment is crucial to prevent damage mechanisms that can compromise the boiler and boiler system. Deficiencies in the water treatment program that result in excursions can cause damage mechanisms that negatively impact the integrity and reliability of the boiler, boiler system, and downstream equipment or processes. Common damage mechanisms include the following:

A. **Corrosion:** One of the most significant issues in boiler systems, corrosion can result from dissolved gases like oxygen and carbon dioxide, low pH levels and under-deposit attack. Corrosion can lead to pitting, stress cracking and general metal loss.

B. **Erosion:** High velocity water and steam can cause erosion, especially at bends and elbows in the feedwater system. This erosion can thin the base material, resulting in leaks and failures.

C. **Scaling/Sludge:** Minerals including calcium, magnesium and silica precipitate out of the water, forming boiler tube scale. The scale is an insulator, reducing heat transfer efficiency and increasing the risk of overheating and tube failure.

D. **Oxygen Pitting:** Oxygen in the boiler water can cause localized pitting, particularly at the economizer inlet and tube weld joints, resulting in tube damage. Pitting occurs with the presence of excessive oxygen in boiler water. It can occur during operation as a result of in-leakage of air at pumps or failure of the boiler water pretreatment equipment.

E. **Corrosion Fatigue Cracking:** Areas subjected to thermal cycling and mechanical vibration can be exposed to mechanical stresses. When combined with corrosive environments, corrosion fatigue cracking, which is inside diameter (ID) initiated, can result. Corrosion fatigue can be impacted by boiler design, water chemistry, boiler water oxygen content and boiler operation. Flexible operations and the resulting start-up cycles can have an impact. The combination of these effects can result in breakdown of the protective magnetite layer on the ID surface of the boiler tube, which exposes the tube to corrosion.

F. **Stress Corrosion Cracking (SCC):** This damage mechanism occurs where a combination of high-tensile stresses and a corrosive fluid are present. The cracking damage typically propagates from the ID. The source of corrosive fluid may be carryover into the superheater from the steam drum or from contamination during boiler acid cleaning if the superheater is not properly protected. It is most commonly associated with austenitic (stainless steel) superheater materials, resulting in either trans-granular or intergranular crack propagation in the tube wall. Stress corrosion (or stress-assisted corrosion) cracks are typically branched with numerous small secondary cracks associated with the main fracture area.

G. **Flow-Accelerated Corrosion (FAC):** This damage mechanism is a localized form of corrosion that occurs in piping and boiler systems due to the combined effects of high fluid velocity/turbulence and chemical reactions on the internal surfaces of pipes and equipment. FAC occurs in carbon steel and low-alloy steels when the protective oxide layer (hematite or magnetite) repeatedly forms, becomes destabilized, and then washes away, leading to accelerated base metal loss. FAC is typically found in areas of boiler water piping systems with higher flow rates and/or turbulence caused by changes in direction (bends, elbows, tees, valves, etc.) and/or downstream of geometry changes. FAC may be found in Single Phase form (water systems) in temperature ranges of 100-400°F (38-204°C) or in Two Phase form (combined steam/water systems) in temperature ranges of 250 – 550°F (121-288°C). In processes outside of these temperature ranges and for higher grade steels containing at least 1.25% Cr, FAC is unlikely to occur.

H. **Carryover:** Mechanical carryover is the process where boiler water, and any suspended and dissolved solids entrained within the boiler water, are carried over with the steam. Vaporous carryover is the process where certain impurities volatilize with the steam and carryover in the steam. See Section D.5 for additional discussion on carryover.

I. **Hydrogen Corrosion:** Hydrogen damage occurs when hydrogen atoms diffuse into the boiler tube material, leading to the formation of methane gas and microcracks within the metal structure. This process weakens the metal and can cause it to become brittle and crack. Improper pH control, high metal temperatures or poor water chemistry can cause hydrogen damage in boilers.

J. **Caustic Embrittlement (caustic cracking):** High pH levels can cause caustic embrittlement when concentrated alkaline solutions accumulate in the tube metal, leading to brittle cracks.

K. **Caustic Gouging:** Elevated pH can result in caustic gouging, where the metal surface is eroded due to the chemical reaction with caustic substances. Areas with high heat input and/or poor circulation are most susceptible to caustic gouging.

L. **Contamination:** Contamination in feedwater and boiler water can occur from various sources, including acid or caustic contamination from demineralizer regeneration, cross contamination from process heat exchangers or untreated water from condenser leaks. Contamination can lead to scale/sludge, deposits and corrosion in boiler systems.

Proper water treatment as part of the asset integrity program and regular inspection, testing and maintenance with trending of results and effective excursion management is essential to mitigate these damage mechanisms and ensure the boiler systems operate as designed.

D.4 Water Treatment Systems

The boiler feedwater and boiler water treatment program scope and parameters are based on the operating and service conditions of the boiler, considering demand requirements, pressure range and temperature, per industry and OEM guidelines. The parameters are site, process and unit-specific and require adjustment case by case, taking a condition-based approach. The following are examples of typical equipment configurations and typical internal/external water treatment regimens for the various pressure classes of boilers.

A. Boilers Operating at 0 psi (0 kPa) to 400 psi (2800 kPa)

Hot water boilers (operating at less than 160 psi [1100 kPa] and 250°F [121°C] where no steam is generated) may only need basic internal treatment of boiler water to control corrosion and deposits. In some cases, high purity demineralized water may be trucked in for the initial system charge. Water makeup rates are typically low, but water softening may be needed.Power boilers in this pressure range are typically either of firetube, (up to 300 psi [2100 kPa]) or package water tube design. The steam is generally used for heating or processes other than a steam turbine. Therefore, superheaters are rare in this pressure class; and strict steam purity limits are not typically required. Water softening is common in this pressure range, and membrane (RO) systems may be seen. Often, water makeup rates are high for these process steam applications; and water treatment equipment must be sized and specified accordingly. A deaerator is often used in these systems, especially towards the higher end of the pressure range. Caustic or phosphate treatment programs are typically used where chemicals are added to the boiler water to precipitate suspended solids and to keep the sludge in a fluid form for ease of blowdown. These programs are typically combined with other feedwater treatment, including oxygen scavenging.

B. Boilers Operating at 401 psi (2800 kPa) – 1000 psi (6900 kPa)

Power boilers in this pressure range will be of larger package water tube or field erected water tube design. Most applications will have a superheater and a downstream steam turbine. Higher quality water is required as the operating pressure increases. With the addition of a steam turbine, steam purity becomes critical. Often, a greater portion of the steam is returned to the system as condensate; and the condensate may require additional treatment (polishing). Some applications in this pressure range may still see high makeup water rates. Deaerators are typical in this range.To meet the higher water quality and steam purity requirements, external and internal treatment schemes are economically compared to achieve a balanced treatment program for minimum corrosion and deposition. Cost of treatment may be balanced by cost of mechanical or chemical cleaning of the boiler, based on frequency of required cleaning. Boilers with more advanced external treatment will require less internal treatment and will typically require less offline cleaning. Again, caustic or phosphate treatment programs are typically used in this pressure range and are combined with other feedwater treatments, including oxygen scavenging.

C. Boilers Operating at 1001 psi (6900 kPa) up to 1500 psi (10,300 kPa)

Power boilers in this pressure range and above are of field erected water tube design. They are almost exclusively used to supply steam to downstream steam turbines via a superheater. In some cases, such as in the pulp and paper industry or chemical applications, a non-condensing steam turbine is used to extract energy and reduce the pressure of the steam before it is used for other downstream processes. In other cases, such as power generation, the maximum amount of available energy in a condensing steam turbine is used to generate electricity. Nearly all steam is recovered as condensate (other than cycle losses). Due to the higher pressures and the steam turbine application, very-high quality boiler water and steam purity is required for boilers operating in this pressure range. Because of the high heat transfer rates, deposits can quickly result in overheating. To achieve this high-purity feedwater, advanced filtration, membrane (RO) systems, demineralizers, condensate polishers and deaerators are typical. In most cases, caustic or phosphate treatments are still used in the boiler. However, their quantity is often minimized at higher pressures due to the additional dissolved solids they add to the boiler water. Volatile treatments such as ammonia or amines are typically combined with oxygen scavenging chemicals in the feedwater.

D. Boilers Operating above 1500 psi (10,300 kPa)

Power boilers operating above 1500 psi (10,300 kPa) are almost exclusively found in power generation and will have superheaters that supply downstream turbines. Condensed steam recovery rates are typically high, and makeup water is relatively low. Due to the higher pressure ranges, ultra-high quality boiler water is required to minimize corrosion and deposition. This quality is achieved through advanced filtration systems, membrane (RO) systems, and multistep demineralizers and condensate polishers (cation, anion, and mixed bed). In some cases, caustic- or phosphate-based water treatment is still used; but many boilers in this pressure range will use All-Volatile Treatment where only volatile feedwater treatment (ammonia or amines) is used under normal conditions. Caustic or phosphate products are avoided as much as possible because of the dissolved solids they add to boiler water.

In boilers operating above 2800 psi (19,300 kPa), the ability to distinguish between water and vapor begins to fade. Therefore, the benefits of a steam drum begin to fade as well. At and above this pressure range, once-through boilers become increasingly common. These boilers have no steam drum, and all boiler water is evaporated into steam with no recirculation loop. For this reason, once-through boilers require even greater quality feedwater than drum-type units. At these pressures, any corrosive agents react very quickly with boiler base materials and any solids carry over can deposit on superheater tubes, causing rapid overheating. The purity of steam required by a steam turbine may exceed the water quality level recommended by the boiler manufacturer, which should be considered when selecting a water treatment program.

Volatile treatment programs are discussed in more detail in Section D.2. As noted, they may or may not utilize oxygen scavenging.

D.5 Steam Purity and Steam Quality

Steam purity and steam quality are key components in maintaining the efficient operation of steam systems, especially in high-pressure and superheated steam applications. Poor steam quality and/or steam purity can lead to damage in downstream equipment.

Steam purity is a measure of the extent of contamination from solids, liquids, or vapors in the steam. Contaminants in steam can result in deposits in downstream superheaters, turbines, valves and other equipment, which can result in reduced efficiency, overheating and potential failures. Impurities such as sodium, calcium, silica, magnesium, iron and copper can lead to corrosion, scaling and erosion in the steam systems. High-purity steam contains very little contamination. Steam purity is measured by the concentration of dissolved solids in the steam. Techniques like specific conductance are used to determine the level of contamination in the steam. When monitoring steam quality to meet downstream equipment limits, ensure the steam is sampled after the addition of any desuperheating water, which may contain contaminants.

Poor steam purity is typically the result of one of the following:

- Boiler water carryover
- Accelerated corrosion rates in steam lines
- Process contamination
- Poor quality feedwater used for desuperheating (in applications with superheaters)

Steam quality is a measure of the amount of moisture in the steam, as expressed as the weight of dry steam in a mixture of steam and water droplets. So, steam of 98% quality contains 2% water. High-quality steam has low moisture content, which is important for efficient energy transfer and preventing damage to equipment. Poor steam quality is typically the result of one of the following:

- Boiler water carryover from poor steam drum separation, high drum level or foaming
- Malfunctioning steam traps, which allow condensation buildup in headers and piping

Carryover is the process where boiler water and/or contaminants are carried over with the steam to downstream equipment. Carryover can negatively impact steam purity, steam quality and downstream equipment or processes. The two types of carryover are mechanical and vaporous.

- Mechanical carryover is the process by which boiler water droplets, and any suspended and dissolved solids entrained within the droplets, are carried over with the steam. Mechanical carryover is commonly caused by poor steam drum separation, foaming or high drum level.
- Vaporous carryover is the process by which volatile contaminants carry over in the steam as vapor. Vaporous carryover is directly related to the concentration of volatile contaminants in

the boiler water that will vaporize with the steam. Silica and sodium are common examples. Note, the extent of the contaminant's ability to vaporize can be pressure dependent.

Water conditioning can alleviate the problem of solids carryover in the steam. Solids can be removed from the feedwater via effective external treatment. A blowdown procedure can also be used to remove the solids carryover from boiler water if they settle out. Blowdown cannot be performed on once-through boilers, as no drum or header is available for solids accumulation. For these boilers, solids must be removed by feedwater conditioning, which is a chemical treatment of the feedwater.

Makeup water may contain many impurities that can cause damage to pressure parts. Atmospheric gases, minerals and organic matter may be present in solution. All of these impurities should be removed to avoid problems with the operation of the boiler. Condensate should also be treated. Although large drum-type units operate relatively well without condensate conditioning, treating the condensate may provide protection against condenser leaks. In units where a chance of condensate contamination exists, such as steam used in industrial processes, condensate treatment should be performed. Condensate polishing is essential in the operation of once-through boilers because of the strict limitations for water quality.