Recovery Boiler Water Management Guidelines

(black italicized text = to be developed, green text = completed, blue text = in progress)
(red text = proposed changes and/or additions for 2025)

1. Clarification/Filtration Systems

2. Deionization Systems

3. Feedwater & RB Water Systems

3.1 Deaerator Systems

3.1.1 Design & Operational Considerations
3.1.2 Chemical Treatment & Control Considerations
3.1.3 Key Maintenance Practices & Protocols
3.1.4 SOPs
3.1.5 Monitoring
3.1.6 Inspection/Documentation

3.2 Feedwater Pump & Piping Systems

3.2.1 Design & Operational Considerations
3.2.2 Chemical Treatment & Control Considerations
3.2.3 Key Maintenance Practices & Protocols
3.2.4 SOPs
3.2.5 ESOPs
3.2.6 Monitoring
3.2.7 Inspection/Documentation

3.3 Feedwater Steam Attemperation Systems

3.3.1 Design & Operational Considerations
3.3.2 Chemical Treatment & Control Considerations
3.3.3 Key Maintenance Practices & Protocols
3.3.4 SOPs
3.3.5 ESOPs
3.3.6 Monitoring
3.3.7 Inspection/Documentation

5. Condensate Systems

5.1.1 Design & Operational Considerations
5.1.2 Chemical Treatment & Control Considerations
5.1.3 Key Maintenance Practices & Protocols
5.1.4 SOPs
5.1.5 ESOPs
5.1.6 Monitoring
5.1.7 Inspection/Documentation

6. Sampling & Testing Protocols

6.1.1 Design & Operational Considerations
6.1.2 Sample Conditioning & Control Considerations
6.1.3 Key Maintenance Practices & Protocols
6.1.4 SOPs
6.1.5 ESOPs
6.1.6 Inspection/Documentation

3.1 Deaerator Systems

3.1.1 Design & Operational Considerations

System Overview

The primary function of a deaerator system is to protect the boiler and condensate system from corrosion by removing oxygen and carbon dioxide from feedwater. It also serves to raise the temperature of feedwater to the boiler.

Basic System Flow Path

The following illustrations represent basic deaerator circuitry. Deaerator systems may vary with respect to component and circuit design. Any variation may impact how the guidelines are employed. The boundaries for this system begin with the steam control valve and the water into the deaerator and end with feedwater leaving the deaerator storage tank.

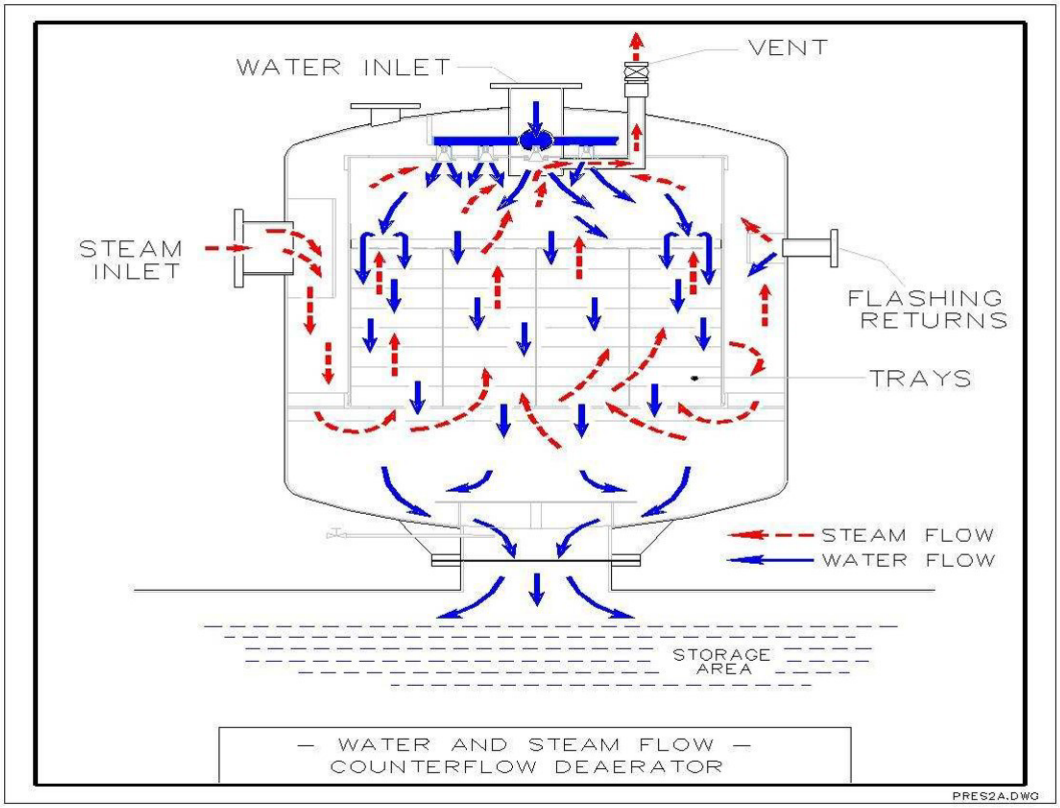


Illustration 3.1 - Typical counterflow deaerator flow path.

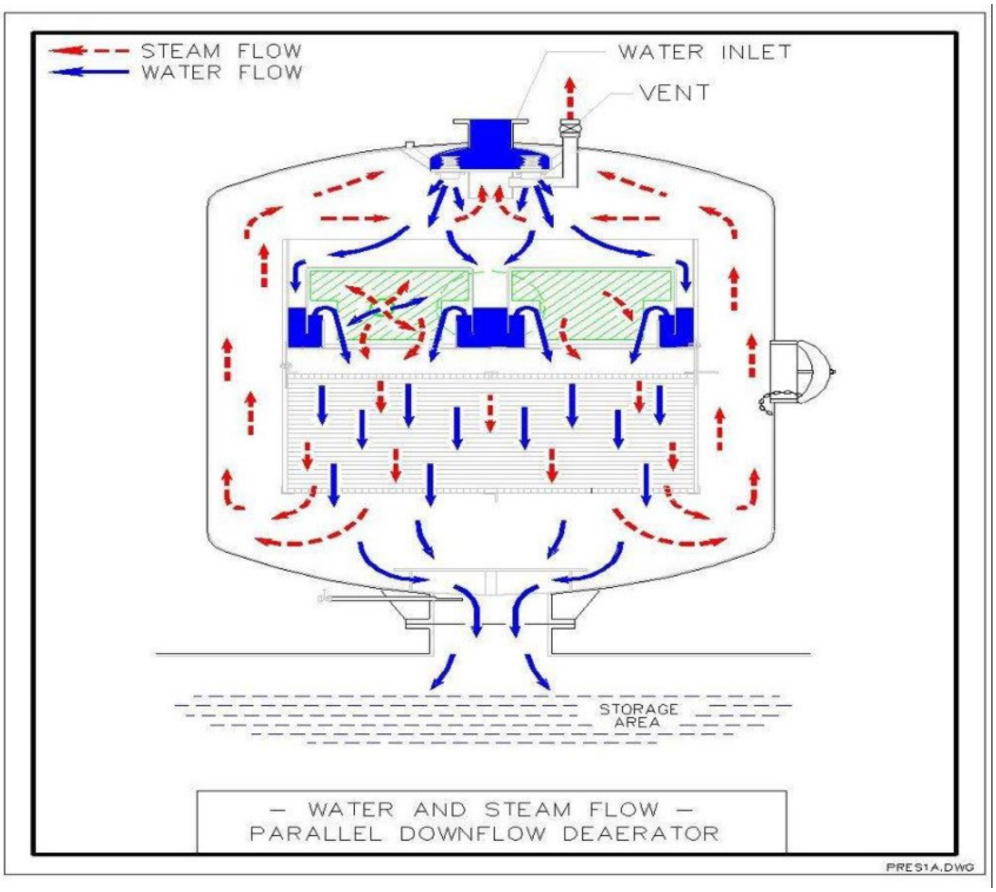


Illustration 3.2 - Typical parallel deaerator flow path.

Deaerator Systems

Basic System Component Design

A basic deaerator system may be comprised of some or all of the following:

- A steam control valve
- A steam check valve
- A steam desuperheater system
- A water flow control valve
- A vacuum breaker on the deaerator head
- A manual deaerator vent valve with a silencer
- Trays and/or spray nozzles to maximize contact of steam and water
- A heater box inside the deaerator head
- A dropleg to the storage tank
- A chemical injection quill
- Deaerator pressure, storage tank level, and storage tank temperature instrumentation
- Feedwater pump automatic recirculation valve (ARC) line penetrations into the tank
- An overflow standpipe
- A high level dump valve
- Vortex breakers at the discharge of the tank.

Basic System Control Technology

Steam is regulated to the deaerator head to control pressure. The steam is sometimes desuperheated to eliminate excessive superheat. Non-condensible gases, such as oxygen and carbon dioxide, are vented via a manual vent valve which is set according to dissolved oxygen levels and/or generally accepted visual plume characteristics.

A water control valve is utilized to ensure an adequate level in the storage tank. A high level automatic dump valve prevents high water levels in the deaerator.

3.1.2 Chemical Treatment & Control Considerations

Water/Steam Purity Impact Assessment

Oxygen and carbon dioxide that enters the deaerator must be substantially removed. Oxygen that is transported to the economizer can contribute to corrosion fatigue, stress-assisted corrosion, pitting and failure of economizer tubes. Carbon dioxide transported to the boiler will volatilize with the steam, increasing the potential for condensate system corrosion.

Deaerators are designed to provide less than 7 ppb of dissolved oxygen without chemical treatment. Sustained operating levels above that will damage the economizer.

Deaerator Systems

Key Chemical Control Variables

Oxygen scavenger is typically added to the feedwater in the deaerator dropleg. If a neutralizing amine is added to the same quill, ensure the compatibility of the amine with the oxygen scavenger.

3.1.3 Key Maintenance Practices & Protocols

System Reliability Impact Assessment

Trays can become dislodged if storage tank level control is poorly managed or if steam pressure is abruptly changed. Operators should be particularly careful to decrease steam pressure on the deaerator slowly to prevent hot water from boiling out the vent valve.

Failure of springs on the spray nozzles can affect oxygen removal efficiency.

Inspection Techniques

In addition to routine visual and NDE inspections. Ensure that trays are securely held down and that spray nozzles have adequate tension and are not plugged. Verify that steam box doors swing freely. Look for cracks in the steam box. (See NACE SP0590 - 2015 Standard Practice Prevention, Detection, and Correction of Deaerator Cracking for further information. Also reference National Board Inspection Code 2.3.1.6.)

When possible, verify the integrity of the steam check valve.

Visually inspect the chemical injection quill.

Inspection Frequency

Mill configuration will determine when there is an opportunity to inspect the deaerator. At a minimum, deaerator inspection intervals should not exceed five years.

Whenever the deaerator is shut down cold, it is considered good practice to visually inspect the deaerator components.

3.1.4 SOPs

3.1.4.1 - *SOP - Deaerator Operation* - An SOP for start-up, shutdown, normal operation, and response to high dissolved oxygen levels should be developed for the deaerator.

3.1.5 Monitoring

3.1.5.1 - *Monitoring - Storage Tank Temperature* - Monitor storage tank temperature to ensure that the water is within 5°F of saturation, based on deaerator section pressure.

	3.1.5.2 - *Monitoring - Steam Pressure* - Steam pressure instrumentation to control steam to the deaerator. A low pressure indication and alarm should be in place.
	3.1.5.3 - *Monitoring - Storage Tank Level* - Low level and high level alarm are required.
3.1.6 Inspection/Documentation	
	3.1.6.1 - *Inspection/Documentation - Pressure Vessel Inspections* - The deaerator and storage tank should be inspected at a frequency in conformance with NACE SP0590 - 2015 or National Board System Design, Operation and Inspection of Deaerators requirements. All inspection data should be documented.
	3.1.6.2 - *Inspection/Documentation - Trays* - Trays and traybox should be inspected at every scheduled cold outage. Ensure that they are secure and aligned properly.
	3.1.6.3 - *Inspection/Documentation - Spray Nozzles* - Spray nozzles should be inspected at every scheduled cold outage to ensure they are tight and not obstructed.
	3.1.6.4 - *Inspection/Documentation - Steam Check Valve* - The steam check valve should be inspected to verify integrity on a mill-determined frequency.
	3.1.6.5 - *Inspection/Documentation - Feedwater Chemical Delivery Systems* - A chemical feed injection quill is recommended when introducing oxygen scavenger. This quill should extend to the center of the dropleg. If oxygen scavenger is added to the storage tank, scavenger should be injected via a quill or pipe away from the wall of the storage tank. The quill should be inspected at every opportunity.
	3.1.6.6 - *Inspection/Documentation - Compatibility of Chemicals* - When multiple chemicals are injected in the same point, compatibility of the chemicals should be verified. It is not recommended to add scavengers and amines in the same quill to avoid pluggage and compatibility concerns.

3.2 Feedwater Pump & Piping Systems

3.2.1 Design & Operational Considerations

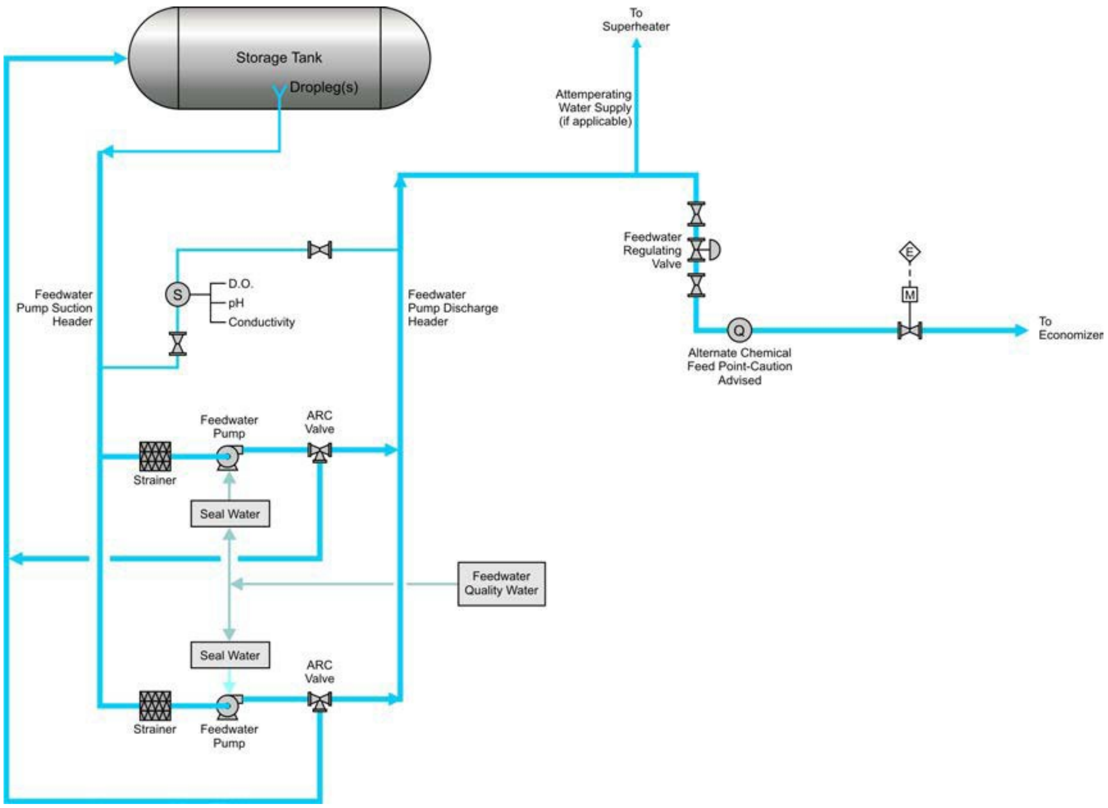
System Overview

Feedwater pump systems are designed to provide:

- Stable drum water level control under all firing conditions
- A spare pump in the event of main pump failure.

Basic System Flow Path

The following illustration represents basic deaerator/feedwater circuitry. Recovery boiler operating systems may vary with respect to component and circuit design. Any variation may impact how the guidelines are employed. The boundaries for this system are from the deaerator storage tank outlet penetration(s) to the inlet of the economizer.



Feedwater Pump & Piping Systems

Basic System Component Design

A basic feedwater pump system is comprised of:

- Droplegs or piping runs from one or more deaerator storage tank to a feedwater pump inlet header
- A feedwater pump suction header (suction side of the pump(s))
- Pump suction strainers
- A feedwater discharge header (discharge side of the pump(s))
- Full capacity pump(s) as well as a full capacity backup pump(s)
- Feedwater pump(s) can be steam- or electric-driven. Preferably the main operating pump would be steam-driven with an electric backup on standby. Where only electric-driven pumps are employed, there should be a secondary source of electrical power supply to the pumps
- Minimum flow recirculation lines (typically routed back to the deaerator)
- A pump shaft seal system (either mechanical seals or packing glands with/without seal water)
- Regulating control valve system, an isolation valve, a non-return valve, a drain valve, and a rapid drain valve
- A high pressure feedwater heat exchanger may be employed for temperature control (not illustrated)
- Chemical injection quills of proper design and materials of construction
- A continuous oxygen analyzer (with trend capabilities) is recommended. The sampling system should have sample extraction capabilities on both the suction and discharge side of the feedwater pump(s)
- Conductivity element with alarm capabilities (located in the dropleg below the deaerator storage tank or discharge side of the feedwater pumps. Discharge side is best practice.)
- Cation conductivity where feedwater is utilized for attemperation (recommended)
- pH element with alarm capabilities (recommended)
- Oxidation reduction potential (ORP) measurement (optional).

Basic System Control Technology

The feedwater flow regulating valve is controlled by a steam drum level control system.

The rapid drain valve and feedwater flow stop valve are controlled by the rapid drain system.

3.2.2 Chemical Treatment & Control Considerations

Water/Steam Purity Impact Assessment

Impurities that enter through the feedwater circuit can result in potential damage to the boiler system circuitry. The source of these impurities can be the deaeration system or the feedwater pump(s). Contamination levels, if significant, can alter water chemistry and result in corrosion of the circuit metallurgy and/or deposit formation.

Key Chemical Control Variables

American Society of Mechanical Engineers (ASME) guidelines should be consulted for a full discussion of chemical control variables, including dissolved oxygen, pH, conductivity, iron, copper, and hardness (ASME guidelines are contained in the Appendix section).

Mills shall maintain emergency standard operating procedures (ESOPs) for reacting to out-of-range feedwater parameters. At a minimum, these shall include oxygen, iron, pH, hardness, silica, and conductivity.

When contamination is suspected, operators should always validate their test results and, once validated, follow the ESOPs that are in place to troubleshoot the problem. The validation step is to ensure that the sample conditioning station or sample preparations are not the source of the apparent contamination.

3.2.3 Key Maintenance Practices & Protocols

System Reliability Impact Assessment

Feedwater pumps and pumping systems can produce/experience high flows and can also be a source of contaminant ingress (dissolved solids, oxygen, iron, etc.). Erosion/corrosion of the downstream piping system is the primary concern.

Inspection Techniques

Inspect pump seal water systems and review seal water quality for adequacy (seal water quality should be equivalent to that of the feedwater).

Identify high risk areas in the feedwater piping system (such as bends, elbows, and any injection quill locations) and employ NDE methods to inspect for flow accelerated corrosion.

Inspect and routinely calibrate the system O_2 analyzer and visually inspect all associated sample piping and valves. Monitor or periodically inspect for the presence of any sample flow restrictions and/or diversion of sample steams that may impact the accuracy of test results.

If raw or mill water is used on sample cooler/heat exchanger, the heat exchanger should be periodically inspected and cleaned.

Inspection Frequency

Strainers - There are instances when strainers foul with materials like fiber and resin. The source of these materials can be water system-related and may have impacted other water support systems and sample monitoring devices. It is recommended that feedwater pump strainers be inspected in accordance with planned feedwater pump maintenance schedules. In addition, it is advisable to monitor pressure drop across the strainers to ensure that the strainers are not accumulating materials that may restrict feedwater flow.

Seal Water Systems - Inspect and review water quality as mill experience dictates.

Feedwater Piping Systems - The mill should develop a protocol that delineates the inspection frequency for flow-accelerated corrosion in high risk areas (typically every 3 - 5 years, but can also use condition-based methodology).

O_2 Analyzers - Units should be inspected and calibrated in accordance with the OEM guidelines. Associated sample piping systems, valves, and sample coolers should be inspected as mill experience dictates.

3.2.4 SOPs

3.2.4.1 - *SOP - Feedwater Iron Levels* - An SOP shall be in place that states the ASME guidelines for iron levels in the boiler feedwater. The SOP should include method of testing, by whom, and how often.

(Note: An operator log sheet or data entry system that specifies all of the above may be an acceptable substitute.)

Oxygen intrusion and process-related iron ingress can both contribute to high iron levels in the feedwater. Low pH and misapplied water treatment chemicals can also elevate iron levels. There are a variety of tests that measure iron in its different oxidation states. The most common method employed is a Millipore™ iron filtration test. Iron colormetric tests are also utilized.

Iron tests can be run on samples taken from various points within the feedwater circuitry. The type of iron test, sample extraction points, and sampling protocols will be a function of system design, chemistry employed, and conditions encountered. The objective of the testing is to identify particulate iron and/or iron corrosion by-products that may potentially contaminate the feedwater.

The deaeration system and the feedwater piping between the deaerator outlet flange and the economizer inlet flange are one source of iron contamination. The condensate system is the other major source of iron.

For additional information regarding iron monitoring, testing, and control (downstream of the economizer inlet) refer to the Economizer and Drum, Tube & Header Circuitry sections of the BLRBAC Water Treatment Guidelines.

Consult your water treatment subject matter expert to determine the best testing protocols to meet your mill's specific needs.

3.2.5 ESOPs

3.2.5.1 - *ESOP - Feedwater Dissolved Oxygen Ingress* - An ESOP shall be in place to address oxygen contamination of feedwater. Possible sources for oxygen in the feedwater include the deaerator and feedwater pump seals.

3.2.5.2 - *ESOP - Feedwater Low/High pH* - An ESOP shall be in place to address both high and low feedwater pH conditions. The ESOPs should address the following for both low and high pH conditions:

- Test validation and verification prerequisites for either condition (pH meter validation, etc.)
- Differentiate between a parameter step change and a gradual change in the trend
- Decision tree to specify at what pH level fire should be removed from the boiler.

3.2.5.3 - *ESOP - Feedwater High Conductivity* - An ESOP shall be in place to address high feedwater conductivity.

BLRBAC requires that recovery boiler feedwater systems have continuous conductivity monitoring and alarm capabilities. There should be a high alarm conductivity setpoint with the appropriate action steps to be taken by the operators in the event of an alarm condition. The instrument department should confirm that the alarm setpoint is as prescribed by the water treatment subject matter expert. The ESOP should address the following for high conductivity conditions:

- Decision tree to specify at what conductivity level fire should be removed from the boiler.

(For specific information on cation conductivity for monitoring feedwater attemperating systems refer to the Feedwater Steam Attemperation Systems section of the BLRBAC Water Treatment Guidelines.)

3.2.5.4 - *ESOP - Feedwater Hardness Ingress* - An ESOP shall be in place that addresses action steps to be taken to address hardness levels above ASME guidelines for boiler feedwater. The ESOP should address the following for high hardness conditions:

- Hardness test validation and verification
- Differentiation between a hardness level step change and a gradual change in the trend
- Alternative test method (colormetric/titrimetric).

Most common hardness sources include:

- Feedwater pump seal water
- Process water hardness-related ingress that may occur in systems upstream of the feed pumps
- Sample cooler ingress.

Consult your water treatment subject matter experts to determine the best ways to deal with hardness ingress issues.

3.2.6 Monitoring

3.2.6.1 - *Monitoring - Feedwater Conductivity w/Alarm Setpoint* - Recovery boiler feedwater systems with continuous conductivity monitoring and alarm capabilities are a BLRBAC requirement. Alarm conductivity setpoint should be validated with the appropriate action steps to be taken by the operators (refer to feedwater hardness ESOP) when the system is in alarm mode or conductivity levels in the feedwater suddenly trend upwards.

3.2.6.2 - *Monitoring - Feedwater pH* - To monitor and identify feedwater ingress contaminants that may be slightly conductive yet acidic in nature (organic acids) or to provide redundant indication when experiencing alkaline ingress (black liquor, etc.), it is required to have pH measurement as a feedwater monitoring tool.

Consideration should be given to the influence of amines upon the pH monitoring and alarm and control setpoints employed. The primary focus should be a discernable and sustainable step change in the feedwater pH reading under normal operating and chemical material balance conditions.

3.2.6.3 - *Monitoring - Feedwater Oxygen Testing & Sampling* - There should be a properly designed and constructed high pressure sample cooling system in place to accommodate testing for dissolved oxygen on both the suction and discharge sides of a feedwater pumping system. The sample extraction points for dissolved oxygen testing are as follows:

- Feedwater pump suction
- Feedwater pump discharge (ahead of the economizer inlet (recommended)).

To optimize test results, the sample conditioning requirements, sample line location, length of sample line run, and sample flow should be taken into consideration when installing a dissolved oxygen sampling system.

The location of the chemical feed point relative to the sample extraction point can influence test results.

Constant feedwater sample temperature and flow rate should be as per the equipment manufacturer's specifications. For more information on installation points, sample flow requirements and temperature limitations, contact/refer to one or more of the following:

- Equipment manufacturing specifications (OEM)
- Your water treatment subject matter experts
- TAPPI TIP 0416-03 "Water quality and monitoring requirements for paper mill boilers operating on high purity feedwater" and 0416-14 "Water quality guidelines and monitoring requirements for paper mill boilers operating with softened makeup water".

Feedwater Pump & Piping Systems

3.2.7 Inspection/Documentation

3.2.7.1 - *Inspection/Documentation - Feedwater Flow-Accelerated Corrosion -* The feedwater piping should be designed to reduce the effect of flow-accelerated corrosion. Flow-accelerated corrosion can be influenced by any changes in operation such as an increase in feedwater flow rate, change in pH, dramatic change in dissolved oxygen levels, or a change in feedwater system chemistry.

There are nondestructive test protocols for feedwater piping that should be conducted periodically to check for flow-accelerated corrosion.

3.2.7.2 - *Inspection/Documentation - Feedwater Pump Mechanical Seals or Packing Glands -* Leakage in and around shaft seal systems can impact feedwater quality. It is a best practice and recommended to reinject cooled feedwater where packing gland systems are utilized.

It is a best practice and recommended to utilize high purity water for mechanical seal cooling.

The feedwater pump seal water system documentation shall delineate standard operational and maintenance practices and established inspection frequencies.

3.2.7.3 - *Inspection/Documentation - Feedwater Chemical Delivery Systems -* A chemical feed injection quill is required when introducing a chemical into feedwater piping.

It is recommended that the point of feed survey (line diagram) be updated annually or following a change in chemistry or feed point. Chemical injection quills should be of proper design and materials of construction.

For more information on installation points, sample flow requirements and temperature limitations, contact/refer to one or more of the following:

- Equipment manufacturing specifications (OEM)
- Your water treatment subject matter experts
- TAPPI TIP 0416-03 and 0416-14.

3.2.7.4 - *Inspection/Documentation - Copper Metallurgy -* Identify the alloys deployed in the recovery boiler water system heat exchangers to determine if there are any potential sources of copper. Common sources of copper include:

- Copper alloy heat exchangers
- Copper alloy steam coil air heaters
- Copper alloy sweetwater condensers
- Turbine condensers
- Dryers
- Heating systems.

Sampling techniques for copper ingress should be reviewed with your subject matter expert.

	If copper ingress is suspected, then samples extracted from the pertinent streams should be sent out to a laboratory for high purity analysis. An action plan should be developed; predicated upon the lab findings. Consult your water treatment subject matter experts to determine the best ways to deal with copper issues.
	3.2.7.5 - *Inspection/Documentation - Feedwater Oxygen Analyzers* - Facilities shall have a routine instrumentation checklist in place that details the maintenance, calibration practices, and inspection of O_2 analyzers and their associated sample piping, valves, and sample coolers.

3.3 Feedwater Steam Attemperation Systems

3.3.1 Design & Operational Considerations

System Overview

Attemperation, sometimes referred to as desuperheating, is the process whereby the boiler superheated steam is cooled with water to obtain a constant steam temperature. Since the water utilized in the attemperation process is introduced upstream of a steam turbine, and/or in many cases introduced within the superheater circuitry, it must be extracted from a reliable source that is relatively pure (trace levels of dissolved and/or suspended solids).

There are several sources of high purity water within the recovery boiler water support system that can be utilized for attemperation water:

- **Sweetwater condenser** (condensed steam from a dedicated heat exchanger) is the water source of highest purity. If properly designed and integrated into the feedwater system, a sweetwater condenser is also the most reliably consistent source of attemperation water.

- **Recovery boiler feedwater** is another attemperation water source that is commonly utilized. In some applications feedwater is a backup supply to a sweetwater condenser. The level of impurities in this water source can vary as water quality from the various support systems (ion exchange systems, condensate systems, etc.) fluctuates. Water treatment chemistry upstream of the attemperation water extraction point can also influence water quality.

- **Turbine condensate** is the third most common source of attemperator supply water and, in some applications, is a backup supply to the two aforementioned water supply systems. The level of impurities in this water source can vary as a function of the purity of the steam supply to the turbine condenser, oxygen, and other contaminants that may be present in the condensed steam. Consideration must be given to condenser leaks that will impact condensed steam water quality.

- **Polished condensate** can be an attemperation water source; however, reliability and consistency factors tend to place this water source in the emergency backup category. If polished condensate is considered for backup purposes, the resin bed must be regenerated with an amine.

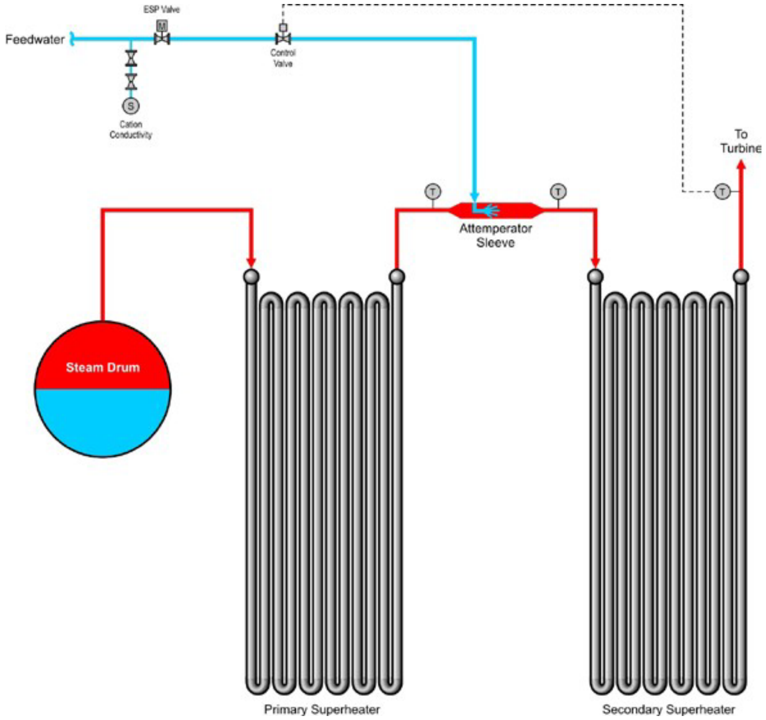
- **Demineralized water**, in very limited applications, is utilized as either a lead or backup attemperator water supply source. Since, in all likelihood, this water is not deaerated, its use as an attemperator supply water source is **strongly discouraged** due to its oxygen content. A detailed corrosion study of all downstream circuitry and steam/water system components is recommended.

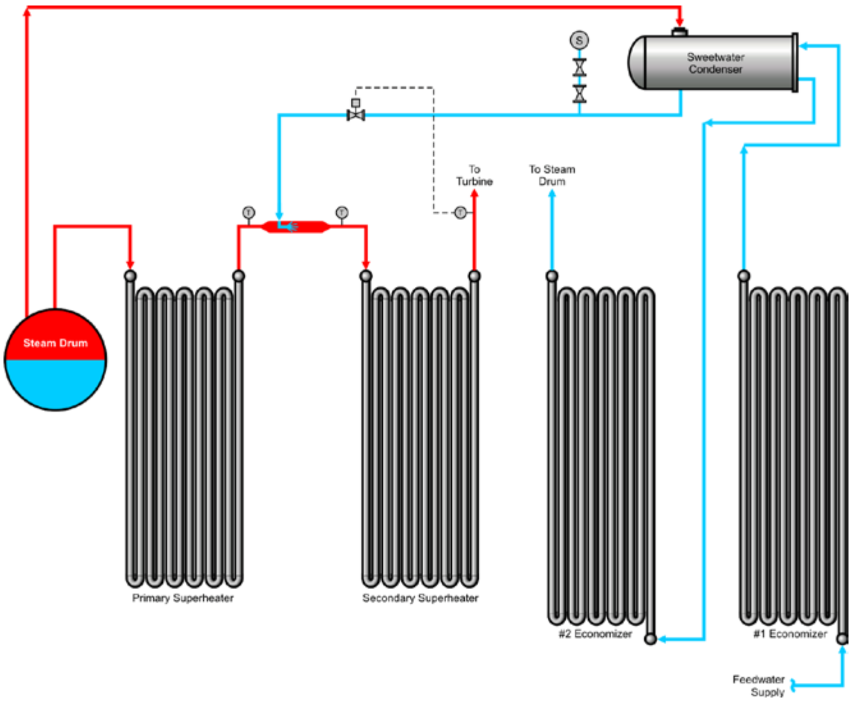
In this BLRBAC guideline, the focus will be upon the sweetwater condenser and boiler feedwater attemperating water systems. Other water sources will be considered as either special applications and/or backup attemperator water supply sources.

Feedwater Steam Attemperation Systems

Basic System Flow Path

The following illustrations represent conventional feedwater steam attemperation system circuitry. Recovery boiler operating systems may vary with respect to component and circuit design. Any variation may impact how the guidelines are employed. The boundaries for this system are from the boiler feedwater system to the superheater outlet.





Feedwater Steam Attemperation Systems

Basic System Component Design

Attemperation with feedwater (upper illustration).

- Attemperator sleeve
- Control valve
- ESP shutoff valve
- Cation conductivity measurement.

Attemperation with a sweetwater condenser (lower illustration).

- Attemperator sleeve
- Sweetwater condenser (metallurgical considerations)
- Control valve
- Sweetwater condenser sample line (for grab sample)
- Steam temperature indication before and after attemperation.

Basic System Control Technology

The attemperator water flow is controlled to sustain the desired superheated steam outlet temperature.

3.3.2 Chemical Treatment & Control Considerations

Water/Steam Purity Impact Assessment

Since the water utilized in the attemperation process is introduced upstream of a steam turbine and/or in many cases introduced within the superheater circuitry, it must be extracted from a reliable source that is relatively pure (trace levels of dissolved and/or suspended solids).

The impurities present in that attemperating water source can impact the reliability of recovery boiler superheater circuitry (if interstage desuperheating is employed) and other key support system operating components (turbines) located downstream of the attemperation water injection point.

Note: Other related water support systems can become contaminated and alter the purity of the attemperation water supply source. Where attemperation systems other than a sweetwater steam condenser are utilized, the water quality of those water support systems should be monitored.

Attemperation water purity can vary on either a continuous or intermittent basis. Therefore sampling, monitoring, and operator notification protocols should be in place that focus upon identifying step changes or intermittent variations in the attemperation water supply under differing makeup water demands and return condensate conditions.

Key Chemical Control Variables

The key control variable in monitoring attemperator water purity is conductivity. Other variables such as pH and sodium also provide meaningful information.

An increase in conductivity in the attemperator water supply can be caused by an increase in cation/anion loading (non-volatile contaminants) and/or an increase in amine/ammonia loading (volatiles typically associated with water treatment). The non-volatile contaminants can deposit in steam/water components located downstream of the attemperation introduction point.

There are two commonly employed methods of monitoring/measuring conductivity:

- **Specific Conductance -** Measures how a water source containing both volatile and non-volatile water contaminants (cations, anions, amines, and ammonia) conducts an electrical current.

- **Cation Conductivity -** Sensitizes the specific conductance measurement and focuses upon only the anion water components in the water source intentionally eliminating amines and ammonia.

Cation conductivity is recommended because the presence of amines and ammonia in the attemperation water source make it difficult to tell the difference between volatile and non-volatile contributors to the conductivity of an attemperating water source. Non-volatile solids can deposit in superheaters and turbines.

To test for the non-volatile components, a cooled-continuous flowing attemperator water sample stream is processed through a small cation exchange column located upstream of a conductivity probe yielding a cation conductivity measurement. The resultant cation conductivity measurement provides a more accurate measurement of the cation/anion loading within the attemperator water supply.

Discernable and sustainable incremental step changes (short-term) in chemical control variables monitored on a continuous or intermittent basis would require an investigation as to probable cause. In such cases, the water treatment subject matter experts should be contacted immediately.

3.3.3 Key Maintenance Practices & Protocols

System Reliability Impact Assessment

The consequences of poor quality water or improper attemperator water dispersion could include:

- Deposit formation within the attemperator (flow restriction)
- Deposition on downstream components (superheater tubes and turbine blades)
- Thermal cycling of components
- Flooding of superheater pendants
- General mechanical integrity issues
- Superheater tube failure.

Inspection Techniques

Attemperator piping should be equipped with a properly designed inspection port so the attemperator can be visually inspected with a borescope. The visual inspection should include, but not necessarily be limited to:

- Spray nozzle assembly (diaphragm, nozzle welds, backing plate, spray head)
- Liner (if applicable)
- Attemperator body (look for erosion or cracks).

If a sweetwater condenser is utilized, it should be inspected for general structural integrity. Metallurgy of the heat exchanger tubes should be verified. If a condensed steam sample line exists, it should be free of obstructions. Temperature control valves should be monitored and maintained to prevent excessive leak-by.

Inspection Frequency

The frequency of inspection for the attemperator piping or the sweetwater condenser system is mill location specific, but typically coordinated/aligned with turbine outages.

3.3.4 SOPs

N/A

3.3.5 ESOPs

3.3.5.1 - *ESOP - Attemperator Water Quality* - An ESOP shall be in place that addresses attemperation water quality. This ESOP should provide guidance if the water quality is determined to be:

- Outside the prescribed operating boundaries for the parameters being monitored
- Undergoing a discernable and sustainable parameter step change.

Your water treatment subject matter expert should be consulted if the attemperator water source changes.

Samples of any suspect attemperation water source should be extracted and saved for future examination during any period of time when one or more of the aforementioned conditions are encountered.

The ESOP should also address what action should be taken if a sustained or intermittent change in the purity of steam is experienced. It should specifically focus upon contamination of attemperation water sources (turbine condensate, sweetwater condenser condensate, etc.).

Feedwater Steam Attemperation Systems

3.3.6 Monitoring

3.3.6.1 - *Monitoring - Sweetwater Condenser Water Sampling* - To have the capability to test the condensed steam for contamination within the sweetwater condenser shell section (i.e., boiler water carryover, feedwater inleakage, metals), there should be a sample extraction point at the attemperation water outlet.

3.3.6.2 - *Monitoring - Attemperator Water Conductivity* - Attemperator water supply sources that exceed 12 µS/cm conductivity should be scrutinized for suitability of use by your water treatment subject matter experts.

3.3.6.3 - *Monitoring - Attemperator Feedwater Cation Conductivity* - Where feedwater is utilized as the primary source of steam attemperation, continuous monitoring of cation conductivity of the feedwater is recommended.

Monitoring cation conductivity requires the installation of a sample cooler and small cation exchange column upstream of the conductivity probe. In systems where the conductivity probe is located directly in the feedwater line, the probe will need to be relocated and made an integral part of the sampling system.

There should be alarm and conductivity setpoints with the appropriate action steps to be taken when the system is outside specified limits.

3.3.6.4 - *Monitoring - Sweetwater Condenser Water Quality* - If the water quality is not monitored on a continuous basis it is advisable to have the water treatment subject matter expert establish a test protocol.

3.3.7 Inspection/Documentation

3.3.7.1 - *Inspection/Documentation - Attemperator Metallurgical Considerations* - It is recommended that the metallurgy of the sweetwater condenser be reviewed for suitability.

3.3.7.2 - *Inspection/Documentation - Annual Review of Attemperator Drawings (P&IDs, Flow Diagrams)* - Maintain up-to-date drawings of the attemperation water system. Include all backup water sources, sample locations, and chemical feed points (if applicable). An annual review of the system drawings and the backup system utilization strategy is recommended.

3.3.7.3 - *Inspection/Documentation - Prohibited Chemistry - Non-Volatile Chemicals* - The addition of non-volatile chemicals upstream of any attemperation water source is strictly prohibited. Dissolved solids (non-volatiles) present in the water can, at elevated temperatures, deposit on component parts and circuits associated with the superheat steam system.

3.3.7.4 - *Inspection/Documentation - Change in Attemperation Water Source* - A management of change document should be in place that addresses what action should be taken if there is a change in attemperating water source. Procedures should include action steps to confirm that the attemperating water is suitable for use as defined by your water treatment subject matter experts.

3.3.7.5 - *Inspection/Documentation - Attemperator Inspection Guideline* - Facilities should develop and maintain their own formalized written maintenance protocol governing the inspection of attemperator system components.

Attemperator piping should be equipped with a properly designed inspection port so the attemperator can be visually inspected with a borescope. The visual inspection should include, but not necessarily be limited to:

- Spray nozzle assembly (diaphragm, nozzle welds, backing plate, spray head)
- Liner (if applicable)
- Attemperator body (look for erosion or cracks).

If a sweetwater condenser is utilized, it should be inspected for general structural integrity. If a condensed steam sample line exists, it should be free of obstructions. Temperature control valves should be monitored and maintained to prevent excessive leak-by.

3.3.7.6 - *Inspection/Documentation - Attemperator Checklist* - As stated earlier, the quantity and purity of the attemperation supply water can impact downstream system components. Poor steam temperature control can exacerbate other problems and further complicate any potential deposition-related concerns.

The temperature control valve position and superheater steam outlet steam temperature conditions should be routinely reviewed and incorporated into a checklist.

3.4 Blowdown Heat Recovery Systems

3.4.1 Design & Operational Considerations

System Overview

Blowdown heat recovery systems are designed to recover some of the latent heat energy within the boiler blowdown water through the process of flashing steam from a tank at a lower operating pressure.

The continuous blowdown system controls the concentration of dissolved and suspended solids in the recovery boiler water, whereby a portion of the most concentrated boiler water is continuously extracted from the boiler steam drum. A small percentage of boiler water (typically 1% - 3% of the feedwater flow) exits the steam drum via a small diameter blowdown line. It should be noted that the location of the blowdown line within the steam drum and the orientation, sizing, and spacing of the orifices can impact how effectively the solids are extracted from the boiler water. The flow of boiler blowdown water can be controlled manually or automatically. Where flow meters are to be employed, the location of a continuous blowdown flow meter requires careful consideration with respect to static head and its positioning relative to the blowdown flow control valve.

Boiler water from the internal blowdown line is routed to a singular blowdown collection tank (flash tank) or, in some applications, a series of cascading pressure blowdown collection tanks.

In some heat recovery systems, a heat exchanger is also utilized to recover some of the sensible heat energy in the residual blowdown water as it is discharged from the flash tank. In some blowdown heat recovery systems, a properly engineered heat exchanger can take the place of the flash tank.

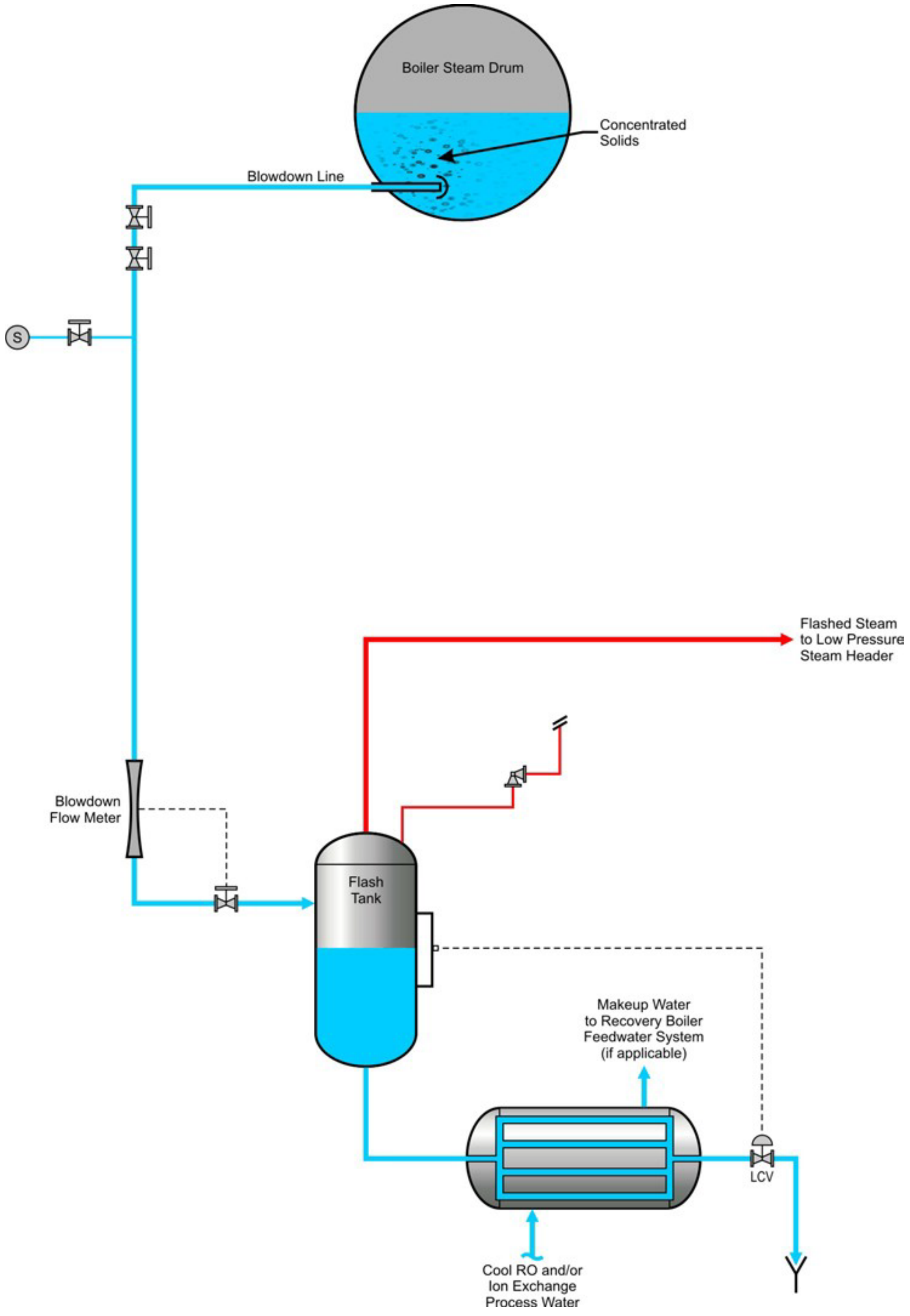
A malfunctioning blowdown heat recovery system can become a source of steam contamination to the recovery boiler water system.

If the flashed steam becomes contaminated with boiler water, recovery boiler deaeration systems and other low pressure steam users can be impacted; ultimately affecting the quality of the boiler feedwater.

Blowdown Heat Recovery Systems

Basic System Flow Path

The following illustration represents basic continuous blowdown system circuitry. Recovery boiler operating systems may vary with respect to component and circuit design. Any variation may impact how the guidelines are employed. The boundaries for the system are from the boiler steam drum continuous blowdown line to the two locations where the blowdown water flashes and the remaining liquid discharges.



Basic System Component Design

A conventional blowdown heat recovery system is comprised of:

- A blowdown line (typically 1" - 1½" diameter) located inside the steam drum
- An external blowdown line (typically 1" - 1½" diameter)
  - Two external manual isolation valves (typically located in close proximity to the steam drum)
  - Manual blowdown valve (with valve position indications)
  - Flow meter (optional)
  - Automatic flow control system (optional)
- A flash tank (with or without internal baffles)
  - Blowdown line penetration(s) into the flash tank steam space
  - Water level sight glass
  - A manual or automatic level control system
  - Steam piping for tying into a low pressure steam distribution system
  - Safety valve
- Additional flash tanks (in series - optional)
- A heat exchanger (typical but optional) supplied with cool RO and/or ion exchanged processed water where a transfer of heat from the boiler blowdown water to the processed water takes place. **Note:** In most continuous blowdown heat exchanger applications that processed water is utilized as recovery boiler makeup water.

Basic System Control Technology

A basic blowdown heat recovery system should have a level control system to maintain boiler blowdown water level within the flash tank.

3.4.2 Chemical Treatment & Control Considerations

Water/Steam Purity Impact Assessment

Boiler water impurities in the flashed steam can distribute throughout the mill's steam distribution system, and can eventually contaminate the low pressure steam supply.

Recovery boiler deaeration systems utilize low pressure steam. Other end users utilize low pressure steam that, when condensed, can return as condensate to the recovery boiler feedwater system.

Flash steam contamination in a blowdown heat recovery system can cause an undesirable increase in recovery boiler feedwater conductivity which, in turn, will result in an elevation of solids levels within the recovery boiler circuitry and, where applicable, in feedwater superheater attemperation systems.

The level of contamination, if significant, has the potential to alter the recovery boiler system chemistry, impact steam purity, and contribute to the formation of waterside deposits and/or contribute to corrosion mechanisms.

Note: Under certain circumstances, contamination of the boiler makeup water supply via a faulty blowdown heat recovery heat exchanger can result in contamination of the water being supplied as makeup to a recovery boiler.

Key Chemical Control Variables

Recovery boiler blowdown water can contain a variety of impurities. The composition and concentration of the impurities is impacted by feedwater quality, chemical program selection (as a function of boiler operating pressure), extraneous contaminate ingress sources, and blowdown control.

When either feedwater or steam is suspected of being contaminated (discernable and sustainable step change), operators should validate their feedwater test results and, once validated, follow the ESOPs that are in place to troubleshoot the problem and identify the source of contamination.

If the source of contamination is boiler blowdown water, then the composition or profile of the contaminants will typically reflect boiler water chemistry.

3.4.3 Key Maintenance Practices & Protocols

System Reliability Impact Assessment

If the purity of the steam exiting the continuous blowdown flash tank, or the purity of the feedwater makeup exiting the heat exchanger (if used) is compromised, it can usually be attributed to one or more of the following:

- Poor mechanical separation
- Poor level control
- Heat exchanger integrity
- Excessive blowdown flows (potential overflow condition).

Inspection Techniques

Flash Tank:

- If there are baffles in the vessel, check for proper alignment
- Inspect the level control shell penetrations for obstructions
- Inspect the blowdown level sensing lines if present.

Heat Exchanger:

- Verify proper operation of any level sensing device
- If a leak is suspected, perform nondestructive testing on the heat exchanger.

Inspection Frequency

A periodic visual inspection schedule should be established. There may also be code requirements which should be considered. Inspection SOPs should be developed and implemented.

3.4.4 SOPs

N/A

3.4.5 ESOPs

3.4.5.1 - *ESOP - Steam Contamination from the Continuous Blowdown System* - It is a best practice to have ESOPs in place that address contamination of the steam. The continuous blowdown tank can be one of many potential sources of steam contamination. If the blowdown tank (flash tank) is suspect and if the flashed steam is utilized in the deaerator, there will be an elevation in feedwater conductivity with no elevation in makeup water conductivity.

3.4.5.2 - *ESOP - Processed Water Contamination of Continuous Blowdown System* - If RO or ion exchange processed water is supplied to the blowdown flash tank heat exchanger and that processed water is utilized as makeup to the recovery boiler feedwater system, it is a best practice to have ESOPs in place that address process water contamination of the makeup water processed through the continuous blowdown heat exchanger.

The blowdown tank heat exchanger can be one of many potential sources of makeup water contamination. In those cases where the blowdown water pressure at the heat exchanger exceeds the processed water pressure and the heat exchanger becomes suspect, there may be an elevation in conductivity in the water being supplied to the feedwater system.

The extent of contamination will be a function of the conductivity levels being maintained in the recovery boiler blowdown water and the extent and nature of the heat exchanger leak.

3.4.6 Monitoring

3.4.6.1 - *Monitoring - Feedwater Conductivity Elevation & the Continuous Blowdown System -* For out-of-compliance results (alarm condition), determine if any changes in feedwater conductivity levels can be attributed to the makeup water supply; the condensate supply or the steam supply to the deaerator.

If a continuous blowdown heat exchanger is suspect, manually test the processed water downstream of the heat exchanger and look for an increase in the conductivity of the processed water supply.

Review your troubleshooting guidelines (ESOPs) that address recovery boiler feedwater contamination.

Review your troubleshooting guidelines (ESOPs) that address recovery boiler condensate system contamination.

It is a best practice to install a high level alarm on the continuous blowdown flash tank.

Check your feedwater conductivity alarm and control setpoints.

3.4.7 Inspection/Documentation

3.4.7.1 - *Inspection/Documentation - Continuous Blowdown Tank Heat Exchanger* - If a heat exchanger is part of the heat recovery system, first, note the pressure relationships of the two fluids entering/exiting the heat exchanger. If the blowdown water can contaminate the process water, instrumentation should be in place to detect and alarm to that condition. If a blowdown heat exchanger is suspect of leaking, isolate the exchanger and observe the impact upon water chemistry at points downstream of the suspect exchanger.

3.4.7.2 - *Inspection/Documentation - Continuous Blowdown Tank Level Control* - Since the boiler blowdown contains dissolved and suspended solids, it is critical that the blowdown water in the flash tank be mechanically controlled at a level that minimizes the potential for contamination of the flashed steam.

Note: Operating the flash tank outside the design specifications (high load conditions, start-up, etc.) can result in boiler water contamination of the flashed steam.

3.4.7.3 - *Inspection/Documentation - Continuous Blowdown Piping*- The blowdown flash tank(s) level should be checked visually on a routine basis as part of the operator's walkdown.

3.4.7.4 - *Inspection/Documentation - Blowdown Piping* - There should be a periodic inspection of blowdown piping for thinning due to corrosion.

Economizer Systems

4.1 Economizer Systems

4.1.1 Design & Operational Considerations

System Overview

The economizer is the last feedwater preheating step before the feedwater enters the steam drum. The economizer recovers heat from the flue gas, elevating feedwater temperature.

Most recovery boiler economizers are integral to the boiler. Typically, they are once through flow bottom-to-top with or without headers to distribute flow at very low velocity to the steam drum. The water pressure must exceed steam drum pressure and, although economizers are located in relatively low temperature portions of the boiler, elevated approach temperatures can result in premature boiling within the upper portion of the economizer. Premature boiling can impact circulation within the boiler circuits and can impact boiler start-up.

The economizer system may incorporate a feedwater air heater (heat exchanger). The economizer may also consist of one or more sections.

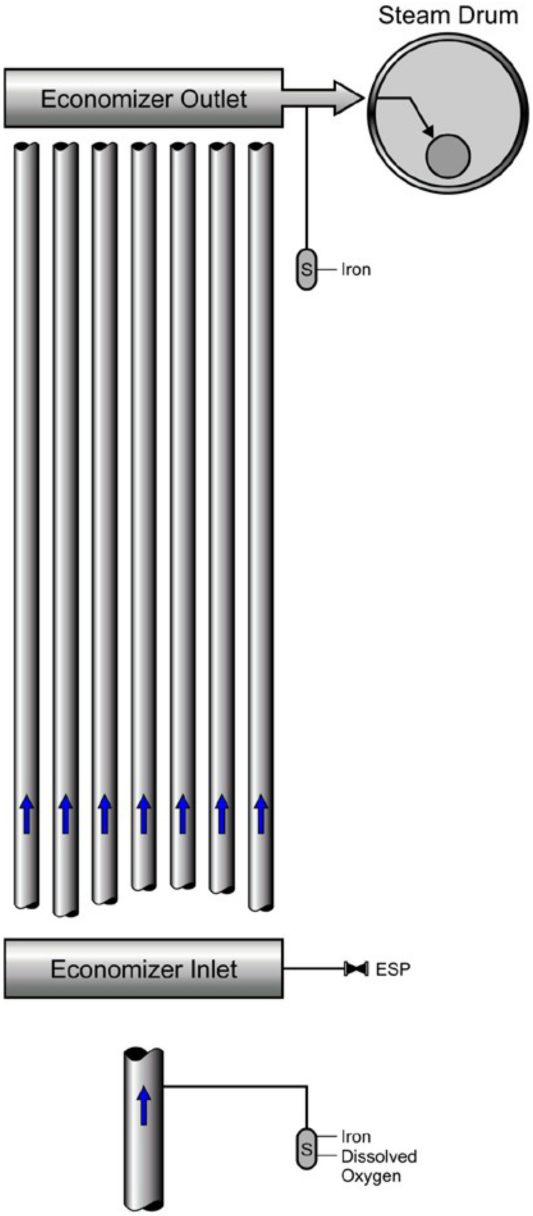
The economizer is subject to the same contaminant concerns as the feedwater piping, but the heat input in this portion of the water circuit, coupled with the low velocities, makes the economizer the first place that contaminants may manifest themselves.

The low feedwater velocities can create a number of problems specific to particulate iron buildup within the lower extremities of the economizer circuitry. If coupled with oxygen and/or non-compliant water parameters or chemistries, concerns regarding corrosion heighten. In many systems the key problem, iron particulate, can transport into the boiler drum, tube and header circuitry.

Economizer Systems

Basic System Flow Path

The following illustration represents basic economizer circuitry. Recovery boiler operating systems may vary with respect to component and circuit design. Any variation may impact how the guidelines are employed. The boundaries for this system are from the point where the feedwater piping enters the economizer inlet header to the steam drum inlet penetration.



Economizer Systems

Basic System Component Design

A conventional economizer system is comprised of:

- Sample point at the inlet of the economizer
- Sample point at the outlet of the economizer
- Heat exchangers (flue gas/feedwater and air/feedwater are optional and not illustrated)
- Boiler water treatment chemical injection quills (optional and not illustrated).

Economizer outlet temperature should be monitored and be below the saturation temperature per alarm setpoint. Refer to OEM recommendation.

Basic System Control Technology

With the exception of economizer ESP and rapid drain valve(s), a basic economizer system does not have any system controls.

4.1.2 Chemical Treatment & Control Considerations

Water/Steam Purity Impact Assessment

From a chemical treatment perspective, the integrity of the economizer must be sustained over time without benefit of routine inspection of the various circuits and headers. Corrosion or deposition within circuitry may result in premature component failure and/or affect the components and circuits located downstream of the economizer. If the location of the failure is above a baffle, water may enter the furnace, resulting in a critical exposure. Therefore, the prescribed guidelines and monitoring tools utilized to assess tube surface conditions and metallurgical integrity should be routinely reviewed and updated as required.

Key Chemical Control Variables

American Society of Mechanical Engineers (ASME) guidelines should be consulted for a full discussion of chemical control variables, including dissolved oxygen, pH, conductivity, iron, copper, and hardness (ASME guidelines are in the Appendix section).

Mills should maintain ESOPs for reacting to discernable and sustainable out-of-bound feedwater parameters. At a minimum, these procedures should address oxygen, iron, pH, hardness, and conductivity.

When contamination is suspected, operators should validate their test results and, once validated, follow the feedwater and economizer ESOPs that are in place to troubleshoot the problem. Ensure that the sample conditioning station is not the source of the apparent contamination.

Economizer Systems

4.1.3 Key Maintenance Practices & Protocols

System Reliability Impact Assessment

Excessive oxygen can cause internal pitting within the economizer. Good dissolved oxygen removal is essential.

Inspection Techniques

It is best practice to periodically remove the handhole caps in the economizer headers and conduct borescope inspection, nondestructive testing, and/or periodic tube sampling of the economizer. In all cases, the purpose is to monitor for any evidence of deposits or O_2 pitting.

Consideration should also be given for periodic iron studies across the economizer. Facilities should consult their water treatment subject matter experts to determine need, frequency, and methodology.

Inspection Frequency

The need to inspect the economizer and the frequency of inspection are driven by a number of factors: Economizer operating history and feedwater quality being two key factors. It is recommended that a timeline that best fits your operating circumstances be established.

4.1.4 SOPs

4.1.4.1 - *SOP - Economizer Iron Monitoring (In/Out)* - An SOP should be in place to monitor iron in and out of the economizer. At a minimum, sampling protocols should be in place that specify flow rates and, if the flow is intermittent, line purge requirements. If a sample line experiences some restriction in flow (over time), an SOP should be in place to address line purge and re-stabilization practices. Refer to TAPPI TIP 0416-03 "Water quality and monitoring requirements for paper mill boilers operating on high purity feedwater" and 0416-14 "Water quality guidelines and monitoring requirements for paper mill boilers operating with softened makeup water".

4.1.5 ESOPs

N/A

Economizer Systems

4.1.6 Monitoring

4.1.6.1 - *Monitoring - Economizer Iron & Oxygen Testing -* There are a variety of tests that measure iron in its different oxidation states. These tests can include visual colorimetric, spectrophotometric analysis, and filtration. The objective of the testing is to identify iron particulate and/or iron corrosion by-products that may contaminate the feedwater supply and the boiler water.

The economizer itself can be a source of, or repository for, iron contamination. For more information on iron sampling and testing, contact/refer to one or more of the following:

- Your water treatment subject matter expert
- TAPPI TIP 0416-05 "Response to contamination of high purity boiler feedwater".

ESOPs shall be in place that address ASME guidelines for iron levels in the boiler feedwater. Refer to the ASME guidelines contained in the Appendix section.

4.1.6.2 - *Monitoring - Economizer Sample Coolers -* A properly designed and constructed high pressure sample cooling system should be in place to monitor water quality across the economizer. Utilization of pre- and post-economizer sample points will provide an indication of whether iron is being removed or deposited in the economizer.

4.1.7 Inspection/Documentation

4.1.7.1 - *Inspection/Documentation - Economizer Chemical Feed Point -* If boiler water treatment chemicals are added upstream of the economizer, the compatibility of these chemicals must be reviewed to determine what potential effects (if any) they may have on the economizer.

As stated earlier, a sample point downstream of the economizer is recommended. Appropriate sample flows must be maintained to ensure that the sample is representative of the process water flow. Sample temperature and time lag must be taken into account when designing these sample points.

Chemical injection quills should be of proper design and materials of construction.

4.1.7.2 - *Inspection/Documentation - Economizer Inspection Tube Sampling -* An economizer tube sample should be taken and inspected at regular intervals. The frequency of sampling and inspection depends on company policy, water consultant guidelines, and as history of economizer tube samples analysis dictates. The composition of the tubes must be analyzed for the presence of contaminants in addition to iron. The tubes must also be inspected for pitting. Facilities should establish written maintenance protocols that determine the scope and frequency of economizer inspections and tube sampling.

	4.1.7.3 - *Inspection/Documentation - Economizer Borescope Inspection* - If there is scheduled economizer repair work, it is best practice to inspect, via borescope, the open circuit.
	4.1.7.4 - *Inspection/Documentation - Economizer Root Cause Analysis* - If there is an economizer tube failure, a root cause analysis should be conducted.

4.2 Drum, Tube & Header Circuitry

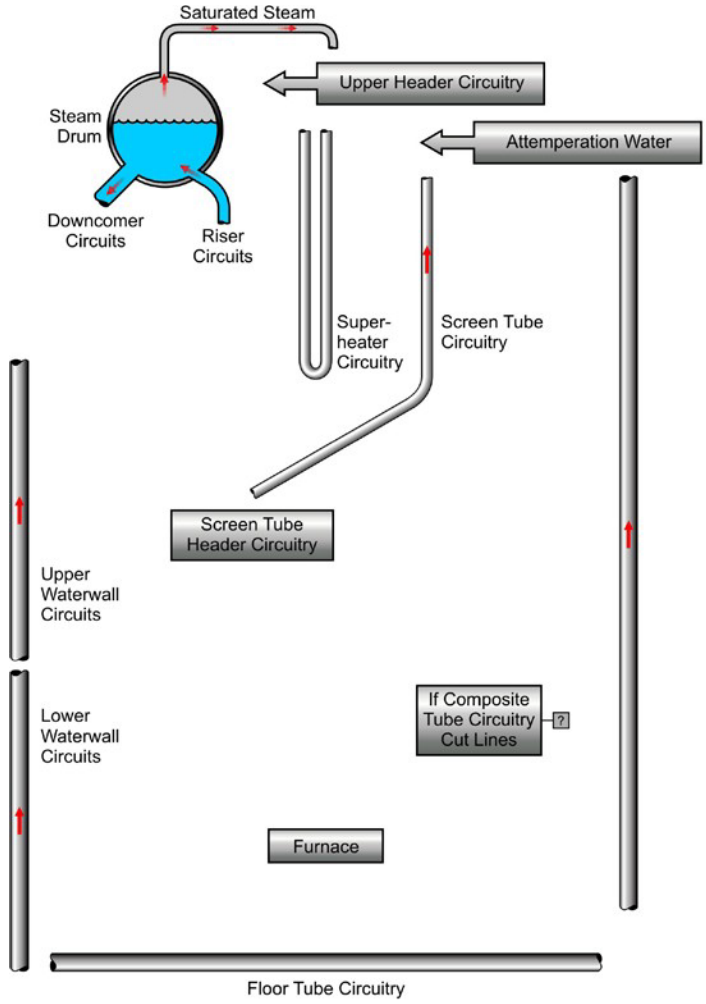
4.2.1 Design & Operational Considerations

System Overview

The boiler water/steam circuitry is designed to provide for the generation and separation of steam from boiler water.

Basic System Flow Path

The following illustration represents basic drum, tube, and header circuitry. Recovery boiler operating systems may vary with respect to component and circuit design. Any variation may impact how the guidelines are employed. The boundaries for the system are the boiler steam drum inlet and the superheater outlet.



Drum, Tube & Header Circuitry

Basic System Component Design

Steam Drum - The steam drum is the primary location where water level is controlled, feedwater is mixed with boiler water, steam is separated from the steam/water mixture, some dissolved and suspended solids present in the water portion of the mixture are removed via a continuous blowdown line, and internal chemical treatments may be applied.

Any modifications to the steam drum internals may impact water level, circulation, steam/water separation, chemical treatment, and blowdown control.

Natural Circulation - As recovery boiler feedwater is converted into steam, the water flow through the furnace circuits is driven by the difference in density of fluids in the risers and downcomers. It is essential that circulation be maintained per the manufacturer's design to maximize the reliability of all recovery boiler tube and header circuits.

Downcomer Circuits - Under natural circulation conditions, downcomer circuits supply the lower furnace circuits. To ensure that the flow of water is predictable, the downcomer circuits are not typically subject to high heat input. Operating conditions that would serve to significantly elevate the water temperature in any of those downcomer circuits may alter the circulation in any furnace circuits.

Lower Waterwall & Floor Tube Circuits - The lower furnace waterwall, floor headers, and tube circuits are supplied with water that will become a steam/water mixture.

Deposits on boiler metal surfaces may reduce the rate of heat transfer and alter the location within the furnace where the heat transfer takes place.

In a recovery boiler, high rates of heat input are to be expected within the lower waterwall region. However, the location of maximum heat transfer can be altered by changes in operating practices and/or design modifications.

Upper Waterwall Circuits - The upper waterwall tube circuits are typically undergoing two-phase flow and, generally, are subjected to a slightly lower heat flux when compared to the lower furnace. The location of maximum heat input can vary, which can influence two-phase flow steam/water ratios.

Where the recovery boiler furnace is of composite materials of construction, the furnace area immediately above the composite weld line can be prone to higher waterside deposition.

Screen Tube & Upper Header Circuits - The screen tube and upper header circuits are subjected to similar heat input as the upper waterwall circuits and are prone to similar two-phase flow-related concerns that can be complicated by their slope, or lack thereof, within the furnace. These circuits tend to be difficult to drain and, due to their location within the furnace, are not often inspected and seldom undergo metallurgical examination.

Superheater Circuits - Saturated steam flows from the steam drum into the superheater circuitry. There are several factors that can impact circuit reliability:

- Start-up and shutdown procedures
- Steam purity
- Front fill or back fill practices (front fill is steam drum-to-superheater fill and back fill is superheater-to-steam drum)
- Fill water quality and chemistry
- Attemperation water quality
- Steam drum internal modifications
- Superheater layup practices.

Basic System Control Technology

Drum level control is key to controlling carryover, carryunder, and overall waterside control:

- Drum centerline is not always the optimal operating level condition. Reference boiler manufacturer's recommendations.

4.2.2 Chemical Treatment & Control Considerations

Water/Steam Purity Impact Assessment

A number of water treatment chemistry considerations can impact recovery boiler waterside conditions from a scale and/or corrosion perspective. The water treatment program should be selected based upon:

- Boiler operating pressure
- Boiler operating history
- ASME guidelines for the feedwater and boiler water
- Site-specific steam purity guidelines
- Other system design factors (thermal, mechanical, chemical, and operational) may influence treatment program choice
- Overall economizer and boiler waterside tube surface conditions (based upon operating history from water quality and contaminant ingress perspectives and deposit weight density (DWD)).

In all cases you should consult with your boiler water treatment subject matter experts for water treatment program recommendations.

Drum, Tube & Header Circuitry

Key Chemical Control Variables

There are a number of factors that can influence chemical treatment program and control:

Mechanical Factors -

- **Blowdown line relative to feedwater pipe orientation and point of chemical addition.** The primary concern is that the boiler water that enters the continuous blowdown line is representative of what would be expected with regard to overall drum and circuit water chemistry. If the feedwater orifices are directed at the continuous blowdown orifices, the cycle chemistry is misrepresented.

- **Feedwater pipe orientation.** The feedwater pipe orientation should be as prescribed by the boiler manufacturer or, in the case of a retrofit to the boiler, per the boiler manufacturer making that retrofit.

- **Chemical feed line location & orientation** (if an internal feed line in the steam drum is utilized on a continuous basis). Please refer to the first two mechanical considerations when assessing chemical feed line location and orientation.

Design & Operational Factors -

- **Boiler heat input.** Changes in design and operating conditions have the potential to change recovery boiler heat input. Changes in where maximum heat transfer will take place can heighten chemical sensitivity in certain circuits and may require a review of chemical treatment control strategy and program selection.

- **Boiler operating pressure.** A change in operating pressure (sustained or intermittent) may necessitate a change in treatment selection and/or chemical control strategy. If a change in operating pressure has been experienced or is being considered, consult with your boiler manufacturer and water treatment subject matter experts.

- **Boiler feedwater water quality.** Any design modification to the pre-treatment or external treatment system (equipment or procedures) can create a discernable and sustainable change in feedwater quality and may require a change in treatment selection and/or control to meet corresponding ASME guidelines based upon the conditions encountered.

  In all cases you should consult your water treatment subject matter experts when a change in water quality has taken place or when a change in the makeup or the condensate treatment processing system(s) is being considered.

Other Factors that Affect Chemical Treatment Program Selection & Performance -

- **Elevated dissolved oxygen levels.** A sustained elevation (reading greater than 10 ppb) in feedwater dissolved oxygen levels can impact chemical treatment performance and boiler circuit metallurgy.

- **Elevated boiler iron levels.** Iron can either be transported into the boiler or generated in situ within the boiler circuits.

Drum, Tube & Header Circuitry

The following are ASME feedwater guidelines for iron at various boiler operating pressures:

Pressure (psig): < 300 = 100 ppb
301 - 450 = 50 ppb
451 - 600 = 30 ppb
601 - 750 = 25 ppb
751 - 1000 = 20 ppb
1001 - 2000 = 10 ppb

The presence of high iron levels in boiler water may be associated with one or more of the following:

- Iron ingress (either continuous or intermittent) from the condensate system
- Following a boiler start-up
- Following/during a change in treatment chemistry
- Following/during an acid or alkali excursion
- Excessive feed of iron dispersants
- Underdeposit corrosion mechanisms
- Lack of a passivation environment following a chemical cleaning
- Incomplete purge of particulate iron from all boiler circuitry following a chemical cleaning.

Chemical treatment parameters for iron control should be determined by your water treatment subject matter expert in keeping with the conditions encountered. It is always advisable to have baseline information before making and/or assessing any chemical changes to the routine iron treatment and control scheme.

- **The presence of known deposits within the recovery boiler circuitry.** The presence of deposits in boiler circuits and headers increases the concerns regarding treatment program selection.

  Waterside deposits have the potential to migrate within the boiler. The movement and relocation can serve to promote corrosion and/or deposition in circuits and headers that may have previously been considered clean and free of deposition.

  The movement of existing deposits within a recovery boiler can be caused by significant thermal, mechanical, chemical, and operational changes within the recovery boiler system. Treatment program selection and dosages should be predicated upon knowledge of those changes. The selection of a location for the removal of boiler tube section for DWD analysis may also be affected by these changes.

  In all cases you should consult with your water treatment subject matter experts if the recovery boiler has a history of waterside deposition.

- **Changes to the existing treatment program.** A chemical cleaning may be required before changing a chemical treatment program. Please refer to the BLRBAC Chemical Cleaning Guidelines for additional information on when to consider chemical cleaning a recovery boiler.

- **Unexpected changes in the feedwater chemistry.** In most, but **not all**, instances an unexpected change in the feedwater chemistry may be accompanied by an increase in feedwater conductivity. In systems where feedwater pH is monitored, correlations between changes in pH and conductivity can help identify a contaminant type and source.

  Note: If you observe a discernable and sustainable change in program chemistry control parameters you should immediately reference your emergency response procedures and contact your water treatment subject matter experts.

  Refer to TAPPI TIP 0416-05 "Response to contamination of high purity boiler feedwater".

- **Steam purity considerations.** Recovery boilers shall have a historical database (preferably a baseline) of steam purity-related information. Continuous sodium monitoring is recommended where generating turbines are supplied steam from the recovery boiler.

  Steam purity analysis of superheated steam is the preferred monitoring method for steam being supplied to generating turbines.

  Steam purity analysis of saturated steam is the preferred monitoring method to determine if chemical and/or mechanical induced carryover from the steam drum is occurring.

- **Historical information.** Collection and consolidation of water quality data and water upset incidents can be beneficial for historical review of recovery boiler operations.

  Note: In all cases, you should provide your water treatment subject matter experts with a historical overview of past water treatment-related anomalies.

Program Selection Options - Dependent on factors such as water quality, operating pressure, boiler history and/or control ability. Current available treatment options for recovery boilers are:

- All organic (lower pressure applications)
- Alkaline phosphate (both low and high PO_4 control setpoints)
- Coordinated pH control
- Congruent control
- Equilibrium control.

In all cases, you should provide your water treatment subject matter experts with a historical overview of past water treatment-related anomalies.

Chemical Feed & Monitoring Practices -

- Care must be taken in selecting chemical feed points and delivery systems. Improperly designed chemical delivery systems can compromise the ability to control water chemistry.

- Sampling points should be selected that will allow you to properly monitor chemical concentrations. An example of suggested sample points can be found in TAPPI TIP 0416-03 "Water quality and monitoring requirements for paper mill boilers operating on high purity feedwater" and 0416-14 "Water quality guidelines and monitoring requirements for paper mill boilers operating with softened makeup water".

- Boiler water sample streams shall have proper flow to ensure that they are representative of the water in the unit. The temperature of the samples should be conditioned to 25°C. Variation from this temperature will affect conductivity and pH, and require compensation. The sample stream shall flow continuously.

- An up-to-date validated system chemical feed point and delivery schematic will minimize the potential for a chemical misapplication. In addition, a detailed review of the chemical delivery methodology will provide a better understanding of what can be expected in terms of statistical control.

4.2.3 Key Maintenance Practices & Protocols

System Reliability Impact Assessment

Properly maintained drums, tubes and header circuitry are essential to the safe and continued operation of any boiler. The methods and techniques employed to accomplish this can be many and diverse. Some of the more common (and beneficial) tools and techniques are outlined below.

Inspection Techniques

Qualified individuals should perform visual inspections in conjunction with appropriate nondestructive examination, periodic analysis of tube samples, and camera and/or fiber optics of accessible tube and header circuits.

Inspection Frequency

The frequency of inspections for the drums, tubes, and headers is mill location specific. The steam drum should be inspected during every major maintenance outage. Inspection of the tube and header circuits will be driven by any number of factors:

- Pressure-part accessibility (tube sampling, repairs or replacement, etc.)
- Mill-specific header inspection guidelines
- Areas identified by destructive and/or nondestructive examination.

Tube sample frequency and protocols vary widely throughout the industry. It is recommended that tube samples be taken at a frequency not to exceed three years. It must be noted that samples may need to be obtained more frequently if upsets have occurred, deposits are suspected, or chemical cleaning protocols are being established.

4.2.4 SOPs

4.2.4.1 - *SOP - Front & Back Filling the Boiler* - For hydrostatic testing, it is recommended that the superheater be back filled with demineralized water or condensate which is free of non-volatile components.

The chemical treatment selected should be all volatile. The type and level of treatment selected will typically be influenced by the backfill water characteristics and the anticipated duration of the lay-up period.

It is not recommended that you front fill the superheater with boiler water. Boiler water can contain chemicals and solids that, once introduced into the superheater section, may cause deposition and/or corrosion within the superheater circuitry.

4.2.4.2 - *SOP - Boiler Water Testing* - Boiler water samples shall be tested at intervals of 4 - 6 hours. Intervals between tests can be longer if continuous monitoring is utilized. Manual entry test data should be retained in accordance with mill document retention policies. At a minimum, tests should include pH, conductivity, silica, and treatment chemical concentration. In low pressure boiler applications, testing should also include P, M and/or OH alkalinity and sulfite.

4.2.4.3 - *SOP - Boiler Water Chemistry Outside Normal Control Boundaries* - An SOP shall be in place that addresses the blowdown and/or chemical feed action steps to be taken by the operator to bring the following water treatment parameters back into control:

- High/low boiler water pH
- High boiler water silica levels
- High boiler water iron levels
- High boiler water conductivity
- High/low boiler water chemical treatment levels
- High/low boiler water alkalinity.

An SOP shall be available for every boiler water test run by the operators.

4.2.4.4 - *SOP - Hardness Testing* - Feedwater hardness limitations are based upon boiler operating pressure and the processing capabilities of the makeup water support systems. An SOP shall be in place that addresses hardness test protocols.

There are two hardness test methods that are typically employed:

- Colorimetric/titration low level limit of detection (100 ppb)
- Spectrophotometric ultra-low level (20 ppb).

Colorimetric Titration Test - Due to limitations in level of detection and differences in visual interpretation, the colorimetric titration test should only be used with softened water makeup.

- The lowest level of detection is at best 100 ppb. If this method is employed, the results as recorded by the operator should be routinely validated utilizing a methodology that has a < 100 ppb level of detection.

- A step change in routine test results should be addressed immediately.

Spectrophotometric Analysis - The ultra-low hardness test is the preferred method to test for hardness in high purity feedwater systems. Due to variability in the results obtained in the field, site-specific control boundaries should be assigned (i.e., 20 - 80 ppb) and monitored. Focus should be given to any step change in hardness levels.

4.2.5 ESOPs

4.2.5.1 - *ESOP - Boiler Water High/Low pH Conditions* - ESOPs shall be in place to address both high and low boiler water pH conditions. The ESOPs should include:

- Test validation and verification guidelines for either condition (pH meter validation, etc.)
- Procedure to confirm chemical delivery systems are functioning as specified
- A check and confirm status of feedwater conductivity alarm status relative to setpoint
- Contaminant identification guidelines (makeup water, condensate return streams)
- A list of water treatment subject matter experts to be contacted in the event of an emergency
- A troubleshooting decision tree that delineates action steps to be taken
- A description of water support system component bypass capabilities (if any exist).

4.2.5.2 - *ESOP - High Boiler Water pH Excursion - Coordinated Phosphate -*

Condition I - Boiler water **pH > 0.2 units** above the normal operating upper limit. *(**Note:** The addition of acid for boiler water pH control is **not** recommended.)*

Refer to ESOP in **4.2.5.1** then proceed to the steps below.

Step 1: Search for the source of contamination in accordance with your SOP guideline for contaminant ingress identification.

Step 2: Increase the frequency of silica, conductivity and pH testing associated with the following systems:

- Feedwater
- Turbine condensate (if applicable)
- Saturated and/or superheated steam (if applicable).

Step 3: Interpret all pertinent data trends and attempt to identify step changes in any control parameter being monitored.

Step 4: Suggested next step (TAPPI TIP 0416-05):

- If steam sodium > 20 ppb - consider removing affected steam turbines from service
- If steam sodium > 100 ppb - consider removing the boiler from service.

In all cases consult the turbine manufacturer for specific limits.

Condition II - Boiler water pH deviation control > **0.2** units above the normal operating upper limit and the **pH is ≥ 10.5**. *(**Note:** The addition of acid for boiler water pH control is **not** recommended.)*

Refer to ESOP in **4.2.5.1** then proceed to the steps below.

Step 1: Refer to your emergency chemical feed and control guidelines and increase the feed of chemicals as delineated by the water treatment subject matter experts in accordance with the higher boiler blowdown control strategy that is in place.

Step 2: Search for the source of contamination in accordance with **4.2.4.3**.

Step 3: Continue to monitor (at a higher frequency) the chemical control parameters associated with the following systems:

- Feedwater
- Turbine condensate (if applicable)
- Saturated and/or superheated steam (if applicable).

Step 4: Interpret all pertinent data trends and attempt to identify step changes in any control parameter being monitored.

Step 5: Suggested next step (TAPPI TIP 0416-05):

- Discontinue any caustic feed.
- If you have a two-drum boiler, initiate short duration mud drum blows at 30 minute intervals.
- If boiler water pH exceeds 11.0 for > 24 hours consider removing the boiler from service.

4.2.5.3 - *ESOP - Low Boiler Water pH Excursion - Coordinated pH Programs -*

Condition I - Boiler water **pH > 0.2 units** below the normal operating lower control boundary. For recovery boilers operating under a coordinated phosphate program, the suggested lower pH control boundary is ≥ 9.0 pH units.

Refer to ESOP in **4.2.5.1** then proceed to the steps below.

Step 1: Search for the source of contamination in accordance with **4.2.5.1**.

Step 2: Continue to monitor (at a higher frequency) the chemical control parameters associated with the following systems:

- Turbine condensate (if applicable)
- Makeup water to the deaerator
- Condensate to the deaerator
- Feedwater leaving the deaerator
- Attemperator supply water (if applicable).

Step 3: Interpret all pertinent data trends and attempt to identify step changes in any control parameter being monitored.

Step 4: Suggested next step (TAPPI TIP 0416-05):

- Feed trisodium phosphate and discontinue feed of any other phosphate with a lower Na/PO_4 mole ratio
- Maintain phosphate in normal range.

Condition II - Boiler water pH deviation from operating pH control > 0.2 units below the normal operating lower limit and **pH 8.0 - 8.6**.

Refer to ESOP in **4.2.5.1** then proceed to the steps below.

Step 1: Increase the feed of chemicals as delineated by the water treatment subject matter experts in accordance with the higher boiler blowdown control strategy that is in place.

Step 2: Continue to monitor (at a higher frequency) the chemical control parameters associated with the following systems:

- Turbine condensate (if applicable)
- Makeup water to the deaerator
- Condensate to the deaerator
- Feedwater leaving the deaerator
- Attemperator supply water
- Saturated and/or superheated steam (if applicable).

Step 3: Interpret all pertinent data trends and attempt to identify step changes in any control parameter being monitored.

Step 4: Suggested next step (TAPPI TIP 0416-05):

- Supplement trisodium phosphate feed with caustic to re-establish normal boiler water pH
- Increase dispersant feed to maintain normal concentration under increased blowdown conditions
- If steam purity remains compromised, open blowdown and increase anti-foam feed
- If steam sodium > 20 ppb - consider removing affected steam turbines from service
- If steam sodium > 100 ppb - consider removing the boiler from service.

Condition III - Boiler water **pH between 8.0 and 6.0** and decreasing.

Refer to ESOP in **4.2.5.1** then proceed to the steps below.

Step 1: Increase the feed of chemicals as delineated by the water treatment subject matter experts in accordance with the higher boiler blowdown control strategy that is in place.

Step 2: Continue to monitor (at a higher frequency) the chemical control parameters associated with the following systems:

- Turbine condensate (if applicable)
- Makeup water to the deaerator
- Condensate to the deaerator
- Feedwater leaving the deaerator
- Attemperator supply water
- Saturated and/or superheated steam (if applicable).

Step 3: Interpret all pertinent data trends and attempt to identify step changes in any control parameter being monitored.

Step 4: Suggested next step (TAPPI TIP 0416-05):

- Discontinue any caustic feed
- If you have a two-drum boiler, initiate short duration mud drum blows at 30 minute intervals
- If boiler water pH does not stabilize or reverse the downward slope within 8 hours the boiler should be removed from service.

Condition IV - Boiler water **pH** < **6.0** pH units.

Step 1: Suggested next step (TAPPI TIP 0416-05):

- Immediately remove boiler from service
- Consider chemical cleaning before restart
- Confirm that the source of the excursion has been identified and eliminated before returning the unit to service.

4.2.5.4 - *ESOP - High Boiler Water Silica -*

Condition I - Boiler water **silica** between **upper control limit and 120%** of that limit.

Refer to ESOP in **4.2.5.1** then proceed to the steps below.

Step 1: Continue to monitor (at a higher frequency) the silica control parameters associated with the following systems:

- Makeup water (demineralizers, etc.)
- Feedwater
- Attemperator
- Turbine condensate (if applicable)
- Saturated and/or superheated steam (if applicable).

Step 2: Interpret all pertinent data trends and attempt to identify step changes in any control parameter being monitored.

Step 3: Suggested next step (TAPPI TIP 0416-05):

- If silica levels exceed turbine manufacturer specifications follow the turbine manufacturer guidelines.

Condition II - Boiler water **silica** between **120% and 140%** of the upper limit.

Refer to ESOP in **4.2.5.1** then proceed to the steps below.

Step 1: Refer to your emergency chemical feed and control guidelines and increase the feed of chemicals as delineated by the water treatment subject matter experts in accordance with the higher boiler blowdown control strategy that is in place.

Step 2: Continue to monitor (at a higher frequency) the silica, conductivity, and pH control parameters associated with the following systems:

- Feedwater
- Turbine condensate (if applicable)
- Saturated and/or superheated steam (if applicable).

Step 3: Interpret all pertinent data trends and attempt to identify step changes in any control parameter being monitored.

Step 4: Suggested next step (TAPPI TIP 0416-05):

- Maximize continuous blowdown (refer to **3.4.7.3** to ensure blowdown heat recovery tank is capable of handling maximum flow)
- If you have a two-drum boiler, initiate short duration mud drum blows at 30 minute intervals if approved by the OEM.
- If silica levels exceed turbine manufacturer specifications follow the manufacturer guidelines.

Condition III - Boiler water **silica** exceeds **140%** of the upper limit.

Refer to ESOP in **4.2.5.1** then proceed to the steps below.

Step 1: Refer to your emergency chemical feed and control guidelines and increase the feed of chemicals as delineated by the water treatment supplier in accordance with the higher boiler blowdown control strategy that is in place.

Step 2: Continue to monitor (at a higher frequency) the chemical control parameters associated with the following systems:

- Feedwater
- Turbine condensate (if applicable)
- Saturated and/or superheated steam (if applicable).

Step 3: Interpret all pertinent data trends and attempt to identify step changes in any control parameter being monitored.

Step 4: Suggested next step (TAPPI TIP 0416-05):

- If these high levels persist, consider shutting down the boiler
- Identify and eliminate the contamination source and flush system prior to returning to service.

4.2.5.5 - *ESOP - Feedwater Hardness Excursions Affecting Boiler Water Chemistry -*

A discernable and sustainable step change in feedwater hardness levels may alter boiler water chemistry in high purity boiler water treatment control schemes (i.e., boiler water pH suppression). In the event hardness levels elevate, proceed to the following:

Step 1: Refer to the SOP on hardness testing and then proceed to verify test results.

Step 2: Refer to your emergency boiler blowdown control guidelines and employ the appropriate boiler blowdown control strategy.

Step 3: Contact your water treatment subject matter experts and immediately proceed to Step 4.

Step 4: Search for the source of contamination in accordance with the SOP guideline for contaminant ingress identification.

Step 5: Continue to monitor (at a higher frequency) hardness and conductivity levels associated with the following systems:

- Makeup water (demineralizers, etc.)
- Feedwater
- Condensate return streams (including turbine condensate, if applicable).

Step 6: Interpret all pertinent data trends and attempt to identify step changes in any control parameter being monitored.

Step 7: Suggested next step (TAPPI TIP 0416-05):

- If you have a two-drum boiler, initiate short duration mud drum blows at 30 minute intervals
- Refer to your emergency chemical feed and control guidelines and increase the feed of chemicals (dispersants, etc.) as delineated by the water treatment supplier in accordance with the higher boiler blowdown control strategy that is in place (ESOP)
- If feedwater hardness levels exceed 2 ppm for 24 hours or 5 ppm for 12 hours, consideration should be given to removing the boiler from service for inspection and a possible chemical cleaning
- Identify and eliminate the contamination source and flush system prior to returning to service.

4.2.5.6 - *ESOP - High FW Iron Levels Elevating Boiler Water Iron Levels - Baseline Iron Data*

To address this ESOP there must be a boiler water iron testing program in place (Millipore iron testing and/or spectrophotometric iron testing).

There will be situations when iron levels will increase beyond established control limits. The iron can either be transported into the boiler or generated in situ within the boiler circuits.

It is recommended that, at a minimum, a baseline iron profile be established in order to proceed with any comparative iron study following any potential change in bulk boiler water chemistry.

Once established the following steps should be employed:

Step 1: Verify test results in accordance with your specific ESOP response guideline for high iron levels.

Step 2: Refer to your emergency boiler blowdown control guidelines and employ the appropriate boiler blowdown control strategy to lower iron levels.

Step 3: Contact your water treatment subject matter experts and immediately proceed to Step 4.

Step 4: Search for the source of contamination in accordance with the ESOP guideline for contaminant ingress identification.

Step 5: Although boiler water capacity and scenario dependent, it would be advisable to alert the subject matter expert and the Utilities Department if after three days the normal upper iron control boundary is a factor of > 3x and the previous 24 trend has reduced the iron levels by 50%.

Step 6: Continue to monitor (at a higher frequency) iron associated with the following systems:

- Makeup water (demineralizers, etc.)
- Feedwater
- Boiler water
- Condensate return streams.

Step 7: Interpret all pertinent data trends and attempt to identify step changes in any control parameter being monitored.

Step 8: Suggested next step:

- If feedwater iron levels exceed 100 ppb for 24 hours or 300 ppb for 12 hours, consideration should be given to removing the boiler from service for inspection and a possible chemical cleaning
- Identify and eliminate the contamination source and flush system prior to returning to service.

4.2.5.7 - *ESOP - RB Leak Detection -* Water chemistry mass balances require reliable and representative sampling, coupled with precision and accuracy in the testing that is employed (if/when the testing is manual and performed in the field).

To help confirm that a leak may exist and/or to determine its location, there are a number of leak detection methods that could support an operator's audio/visual assessment regarding a potential leak condition.

Fireside acoustic (noise) indications and waterside steam, water and/or chemical mass balance determinations often can add credence to operator walkdown findings.

Steam/water flow mass balances typically require either accurate flow measurements or a reliable set of operating conditions or trends to measure against a suspect change in flow.

Regardless of the type of leak detection monitoring method, an ESOP should be in place that defines what action steps are to be taken to validate the significance of any noise indication and any mass balance-related finding. Details shall be provided regarding the water chemistry-related and flow-related parameters to be reviewed.

4.2.6 Monitoring

4.2.6.1 - *Monitoring - Feedwater Inlet Temperature to the Drum* - Generation of steam in the feedwater (economizer) will impact circulation properties within the boiler circuitry. Adhere to the manufacturer's recommended requirement regarding minimum differential temperature between the economizer outlet and the steam drum. If the applicable instrumentation is in place, a high temperature alarm shall be used to alert operations to the potential of a steaming condition within the economizer.

4.2.6.2 - *Monitoring - Boiler Lower Furnace Temperature* - Thermocouples in the lower furnace walls (usually between primary and secondary air) can provide a temperature profile of the high heat zone. In some instances, three-element chordal thermocouples can provide useful information regarding tube surface conditions.

4.2.6.3 - *Monitoring - Saturated Steam Purity* - Steam purity measurement using an online sodium analyzer can be used to detect potential problems in the superheater and downstream steam users.

4.2.6.4 - *Monitoring - Cameras & Fiber Optics* - Whenever tube samples are collected or a header is open for inspection, it is recommended a video inspection be performed.

4.2.6.5 - *Monitoring - Boiler Water Iron* - If there are **no** iron filtration systems, process steam-related interlocks, or high particulate level divert systems in place, at a minimum, boiler water iron tests (filtration or photometric method) should be run every 8 - 12 hours. The results shall be recorded and retained in keeping with department data management practices.

4.2.6.6 - *Monitoring - Boiler Water Silica Monitoring (Colloidal Silica)* - Since colloidal silica cannot be easily detected in the recovery feedwater system, at a minimum, boiler water silica tests should be run every 8 - 12 hours.

4.2.7 Inspection/Documentation

4.2.7.1 - *Inspection/Documentation - Steam Drum Blowdown Line Orientation* - The blowdown line should be oriented to collect the boiler water with minimal influence from the feedwater line and chemical feed point. The blowdown line is typically oriented in the 12:00 position and should be free of any restrictions. Neither the feedwater line nor the chemical feed line orifices should be directed towards the blowdown line. The feedwater line, chemical feed line, and blowdown line orifices should be oriented in accordance with manufacturer's guidelines and shall be verified every time they are removed for maintenance.

Important: Boiler cycles of concentration may not be accurately reported if the internal lines in a steam drum are incorrectly installed or improperly oriented.

	4.2.7.2 - *Inspection/Documentation - Boiler Waterside Condition -* Water quality analysis, deposition analysis, and metallurgical analysis (DWDs, locations, etc.) shall be documented and retained. Any changes in operating practices and upsets shall also be documented and communicated to water treatment subject matter experts.
	4.2.7.3 - *Inspection/Documentation - Boiler Water Treatment Sample Points -* It is recommended that a sample extraction point survey be on file and updated annually or following any modification to the boiler and/or its water support system.
	4.2.7.4 - *Inspection/Documentation - Boiler Water Treatment Feed Points -* It is recommended that a chemical feed point schematic be in place and updated when changes are made to feed point or chemistry.
	4.2.7.5 - *Inspection/Documentation - Boiler Visual Inspection Checklist -* Thorough visual inspections are the first line of defense for any boiler and should be conducted at each major maintenance outage. An inspection checklist should be developed/maintained that is tailored for each area of each specific boiler.
	4.2.7.6 - *Inspection/Documentation - Boiler Visual Inspection Protocols -* Visual inspections should be supplemented with appropriate NDE methods and with tube samples. The detailed protocols governing these supplemental inspections should be developed by the mill.
	4.2.7.7 - *Inspection/Documentation - Boiler NDE Program -* Each mill should develop and/or maintain a program of NDE inspection as a supplement to the visual inspection. It is suggested that any NDE results be tracked, trended and compared to minimal wall values via an established program or protocol. The establishment of "flag values" (values approx. 10% above minimum wall) can be a valuable tool in identifying areas of concern and planning/budgeting for needed repairs or replacement. Refer to TAPPI TIP 0402-18 "Ultrasonic testing (UT) for tube thickness in black liquor recovery boilers".
	4.2.7.8 - *Inspection/Documentation - Boiler Tube Deposit Weight Density -* DWDs obtained from tube sample results should be analyzed and could be used to establish chemical cleaning frequency and chemical cleaning protocols.

4.2.7.9 - *Inspection/Documentation - Boiler Steam Drum -* Inspect hardware integrity, baffle plate condition, and the general integrity of all major internals.

- Look for signs of any deposits in the drum, evidence of steam blanketing, or standing water. Obtain samples for analysis of any noted deposits and document the location.
- Check the physical condition of the drum for indications of any pitting or cracks, including ligament cracking.
- Check the physical condition of any tube plugs.
- Inspect for proper metal passivation and the condition and appearance of a normal drum level line (which would indicate consistent water level).
- Check the condition of steam space screens and chevrons.
- Check that all instrumentation taps are properly secured, open, and clear. Consider borescoping as a means of verification.
- If accessible, inspect saturated steam sampling lines/headers.
- Check all threaded or flanged joints for evidence of leaks.
- Visually inspect the bottom seats of all safety valves.
- Consider borescoping risers, downcomers, and generating bank tubes (which may require removal of bellyplates) based on visual inspection results.

In addition to the visual inspection for two drum boilers, consideration should be given to periodic IRIS (scans) inspections as applicable. Refer to TAPPI TIP 0402-18.

4.2.7.10 - *Inspection/Documentation - Boiler Feedwater Chemical Injection Quill -* Consider removing and inspecting the feedwater injection quill to ensure no pluggage or damage. NDE of downstream piping is recommended on major outages.

4.2.7.11 - *Inspection/Documentation - Mud Drum -* A visual inspection of all tubes for deposits. Specifically, check the metal surfaces into the bends of tubes in the 10:00 and 2:00 positions for unusual signs of deposition.

- Inspect the bottom of the drum for standing water or deposits.
- Ensure all downcomer covers are in place and that an accountability system is in place to ensure they are removed prior to start-up.
- If applicable, inspect the mud drum blowdown/baffles for proper clearance and orientation and that they are properly secured with the plates in place.
- Ensure the drum is properly and thoroughly cleaned prior to closeout (this should be part of the inspection checklist recommended above under steam drum).

4.2.7.12 - *Inspection/Documentation - Boiler Headers -* Following major pressure part work and/or chemical cleaning, inspect affected headers for sludge and debris.

	4.2.7.13 - *Inspection/Documentation - Boiler Furnace -* A visual inspection from inside the furnace should be conducted on all accessible boiler tubes (i.e., floor, waterwalls, screen, generating bank, superheater, etc.). Particular attention should be paid to any cut lines or change of materials. Also look for any evidence of bulging or discontinuity.
	4.2.7.14 - *Inspection/Documentation - Boiler Near Drum/Mud Drum Furnace -* In addition to the visual inspection, special consideration should be given to periodic near drum inspections where applicable.
	4.2.7.15 - *Inspection/Documentation - Root Cause Analysis -* If there is a tube failure, a root cause analysis should be conducted.

4.3 Chemical Cleaning

4.3.1 Introduction & Definitions

Cleaning Purpose

The purpose of chemical cleaning is to remove waterside deposits without causing appreciable internal metal loss. Achieving this will minimize tube damage caused by overheat and/or corrosion. The chemical cleaning covered in this document is to be performed on a boiler that is **off-line in a non-operating state**.

Typical Recovery Boiler Cleaning Focus Areas

Chemical cleaning focus areas are the wetted surfaces of a boiler, including drums, tubes, and headers. Additional circuitry may or may not include the feedwater air heater, economizer, and sweetwater condenser. Recovery boiler operating systems may vary with respect to component and circuit design. Any variation may impact how the guidelines and monitoring tools in this document are employed.

While superheaters may become contaminated with deposits, chemical cleaning of superheaters is a specialized process that is rarely performed on a recovery boiler and requires specialized engineering. Chemical cleaning of superheaters is not covered in this document.

Definitions

Acid Cleaning - The removal of deposits by means of an acidic solvent.

Air Bladders - A pneumatic device used to prevent a solvent from entering an area of the boiler that is not to be cleaned.

Alkaline Boilout - A procedure for removing organic residue (for example: rolling compounds, preservatives, cutting oils, or black liquor) and debris from wetted surfaces following new construction, refurbishment, or a contamination event.

Backfilling/Forward Filling - Filling any boiler component with properly treated water to establish and verify a water block. Backfilling adds properly treated water to a superheater, while forward filling adds properly treated water to the inlet of the economizer.

Chelant Cleaning - The use of an organic solvent (such as EDTA or citric acid) that sequesters the metallic components of a deposit.

Chemical Cleaning - The use of chemicals to remove waterside deposits. This may be a pre-operational cleaning or the removal of waterside deposits that have accumulated during the operation of a boiler.

Composite Drain Sample - A representative sample of a chemical cleaning stage collected over the duration of draining the solvent from the boiler.

Deposit Analysis - A laboratory procedure for the identification and quantification of inorganic and organic components within a tube sample deposit. The composition and concentration of these components can be determined as needed.

Deposit Weight Density (DWD) - A measure of the amount of deposit on the wetted surface of a tube sample over a given area (usually in g/ft^2 or mg/cm^2).

EDTA (Ethylenediaminetetraacetic Acid) - An organic sequestering/chelating agent that is used in different forms, depending on the application, to remove deposits.

Excursion - Deviations outside standard control limits.

Inhibitor - A chemical that is added to the chemical cleaning solvent to minimize attack on the parent metal.

Iron Oxide - A reaction product of iron with oxygen. There are two primary iron oxide forms in boiler deposits; hematite (red - Fe_2O_3) and magnetite (black - Fe_3O_4).

Loss on Ignition (LOI) - A measurement that includes organic components in a tube sample deposit. The measurement may include decomposition products of the LOI test, and therefore requires subject matter expert interpretation of the results.

Mill Scale - Iron oxide deposits formed during tube fabrication.

Neutralization - The pH adjustment of a residual cleaning solvent to halt a reaction on metal surfaces. It is also a process for pH adjustment of chemical cleaning waste streams.

Passivation - A process for establishing a protective oxide coating on a cleaned metallic surface.

Phosphate Hideout - A condition where phosphate complexes reversibly with iron and sodium under changing boiler load. It typically manifests as lower-than-expected phosphate levels and an increase in pH for a given phosphate dosage.

Pre-Operational Chemical Cleaning - The removal of organic matter, mill scale, and debris from the waterside surface of a new boiler or boiler component prior to being put into operation. It typically includes an alkaline boilout followed by mill scale removal. A vapor-phase cleaning and/or steam blow may be incorporated into a pre-operational cleaning, but is outside the scope of this document.

Solvent Efficacy Test (Dissolution Test) - A laboratory test on a tube sample to validate a proposed chemical cleaning process. This test is performed prior to a chemical cleaning.

Videoscope - A tool used to visually inspect boiler waterside surfaces. Also referred to as a borescope. For boiler inspection purposes, a videoscope should have recording capabilities.

Water Block - The use of water to stop the flow of a cleaning solution into boiler circuits that are not intended to be cleaned. Backfilling a superheater is an example.

4.3.2 Cleaning Determination Protocol

This section covers key information that should be considered when evaluating whether a chemical cleaning is necessary. Owners of recovery boilers shall develop a plan or standard to determine a threshold for chemical cleaning utilizing the information presented in this section.

4.3.2.1 - *Determine History*

- **Evaluate previous cleanings.** Valuable information can be learned from a review of past chemical cleanings. Note if there were any departures from the cleaning plan.

- **When last performed/frequency history.** Make a note of how often the unit has been cleaned and when the last cleaning occurred.

- **Deposits removed during previous chemical cleanings.** A history of composite drain sample analyses from past cleanings are often indicative of the deposits to expect during future cleanings. One-time upsets or evidence from a deposit analysis may indicate the need to consider deviation from previous chemical cleaning formulations.

- **Quantitative & qualitative data.** DWD and deposit analysis will play a significant role in determining what chemistries to use for a cleaning. Deposits can be highly localized, and may not be accurately reflected in a single tube sample. Analysis of deposit composition is another consideration, as certain deposits are much more likely to result in overheating of tube walls. Other useful data may include:

    - Rate of growth of the DWD
    - Tube failures from waterside deposits
    - Tube temperatures from chordal thermocouples.

  Deposits can cause overheating of tubes. High heat zones, low flow circuits, bends in tubes, and sloped/horizontal tubes can lead to higher deposit levels. During boiler inspections watch for signs of overheated tubes. Items to monitor should include:

    - Tube thinning/erosion
    - Surface irregularities
    - Visible bulges on the outside of tubes
    - Fireside corrosion.

- **Water quality changes or upsets.** Feedwater quality changes may alter deposit accumulation in the boiler. Water quality upsets have the potential to create new deposits or relocate existing boiler deposits. Some examples are listed below:

    - Condensate or makeup water contamination
        - High or low pH excursion
        - Liquor contamination
        - Fuel oil contamination
        - Hard water contamination
    - Phosphate hideout
    - Water treatment program changes.

Chemical Cleaning

4.3.2.2 - *Review Major Rebuilds/Modifications*

Rebuilds, upgrades, or changes in operating practices can alter heat release locations in a boiler, which may alter where deposits form. Changes in operating pressure affect flow rates in tubes, which can create areas of high deposition in regions that have not historically experienced such issues.

If sections of wall panels have been replaced, and a mill typically uses these areas for tube samples, the inside surfaces of the sample may not reflect conditions in the rest of the boiler.

4.3.2.3 - *Determine Current Conditions*

- **Ability of tubes to withstand a chemical cleaning.** Evaluate whether a chemical cleaning is practical. Examples of conditions to consider:

    - Plugged tubes
    - Evidence of overheat
    - Reduced wall thickness
    - The amount/layering/composition of scale on boiler tubes.

4.3.2.4 - *Coordinate Pressure-Part Replacement Plans*

If major pressure-part replacement is planned, the new components should receive an alkaline boilout. This can be performed once the tubes are in the boiler, or it may be performed prior to installation.

If an alkaline boilout is to be performed, the economics of a full chemical cleaning should be evaluated. If the pressure-part replacement was due to excessive deposits, the entire unit should be chemically cleaned.

4.3.2.5 - *Typical Cleaning Criteria*

Time-Based Criteria -

Policies are commonly set that dictate a maximum time between chemical cleanings of a recovery boiler. A typical interval is 5 - 10 years. Many operators prefer time-based intervals because data-based decisions are from information that is subject to interpretation. Additionally, the selected sites for tube samples may not reflect where the heaviest deposits are located.

Time-based intervals should be shortened in the event of a significant water chemistry excursion. Time-based intervals are often used in conjunction with data-based criteria, wherein specific data drives the interval as long as the predetermined time interval is not exceeded; this is considered to be a best practice.

Data-Based Criteria -

There are several types of information that can be used to make a data-based chemical cleaning decision. These are listed below. An educated decision requires assessment of more than one type of data.

- **DWD/Deposit Analysis -** Operating companies should develop a DWD criteria for determining when to clean a recovery boiler. See Section 4.2.3 for DWD frequency recommendations. The following are some OEM recommendations for evaluating chemical cleaning needs:

  B&W

  B&W recommends *planning* a chemical cleaning if hot side DWD values, obtained via the mechanical scraping method, are:

  - < 1000 psi; 20 - 40 g/ft^2 for low pressure boilers (< 70 bar; 21 - 42 mg/cm^2)
  - 1000 - 2000 psi; 12 - 20 g/ft^2 and for all recovery or refuse-fired boilers (70 - 140 bar; 13 - 21 mg/cm^2)
  - > 2000 psi; 10 - 12 g/ft^2 for high pressure power boilers (140 bar; 11 - 13 mg/cm^2).

  Reference A: B&W PSB-44

  Valmet

  Valmet recommends *chemically cleaning* any boiler in a paper mill if the hot side or cold side deposit, as obtained preferably via bead blasting, is:

  - < 1000 psi; 20 - 40 g/ft^2 (<70 bar; 21 - 42 mg/cm^2)
  - 1000 - 2000 psi; 12 - 20 g/ft^2 (70 - 140 bar; 13 - 21 mg/cm^2)
  - Or if there are any localized heavy deposits visible on the waterside of a tube.

  Reference B: Valmet Technical Paper Series Paper Mill Boiler Chemical Cleaning - Why, When and How. September 2016

  Andritz

  Andritz defers to Teollisuuden Vesi for *chemical cleaning guidelines* for a recovery boiler. Andritz recommends a chemical cleaning for a new recovery boiler, after major retrofits, or an existing recovery boiler which exceeds the following DWD readings:

  - 40 - 70 bar; < 50mg/cm^2 (575 - 1000 psi; 46 g/ft^2)
  - 70 - 100 bar, 30 - 45 mg/cm^2 (1000 - 1440 psi; 28 - 42 g/ft^2)
  - 100 - 140 bar, 20 - 30 mg/cm^2 (1440 - 2000 psi; 19 - 28 g/ft^2)
  - > 140 bar, 15 - 25 mg/cm^2 (> 2000 psi; 14 - 23 g/ft^2).

  Reference C: Teollisuuden Vesi Chemical Cleaning Guidelines, dated May 31, 2019.

Thermal conductivity varies due to deposit composition, therefore chemical cleaning thresholds should not be based on DWD alone. Samples should be taken at high heat zones and areas of low circulation; however, high deposition has occasionally been found in areas of low heat input. Other locations where a tube sample extraction for DWD analysis may be warranted include areas of visible overheat. If a boiler has experienced tube failures from overheat, it would be prudent to take a sample from an adjacent tube.

- **Excursions -** The history of feedwater/boiler water excursions since the last chemical cleaning should be used in the evaluation process. See Section 4.3.2.1 for some examples of excursions. The severity and duration of the excursion(s) also need to be considered.

- **Tube Failures -** The history of boiler tube failures caused by waterside corrosion and/or deposits should be considered.

- **Videoscope (Borescope) Inspection -** Videoscope inspection is an additional nondestructive means of determining the condition of internal tube surfaces. It also provides a record of the condition of a given tube from outage-to-outage. The deposition as seen by videoscope is qualitative and subject to interpretation.

- **Other Nondestructive Tests -** There are other methods that may provide tube deposit indication. Methods that have been employed include x-rays, thermal scans, and specialized ultrasonic technology.

4.3.3 Chemical Cleaning

4.3.3.1 - *Pre-Cleaning Tasks*

A tube sample should be sent out for analysis as soon as practical; prior to the scheduled chemical clean. The tube sample should be dry saw-cut. After extraction, the tube sample should be handled carefully so that the internal deposit is not dislodged and immediately taped at both ends to prevent loss of deposit. Detailed guidance on tube sample removal, shipment, and analyses is available from ASME (see Reference D: ASME Section CRTD-Vol 103). All tube samples should be clearly identified with the hot and cold side, which area of the boiler it came from (including the wall, if applicable), and the elevation that it came from.

Several sections of this tube should also be retained for the chemical cleaning company to use as test material for a selected chemistry. Chemical cleaning labs prefer tube samples that are at least 18" (45 cm) in length. Ensure that the original tube sample is long enough to send a portion to an analytical lab and a portion(s) to the chemical cleaning lab.

4.3.3.2 - *Chemical Cleaning Selection Criteria*

The cleaning process is typically selected based on the composition of the deposit, the density of the deposit, and morphology of the deposit. Certain deposits will shield others, and can yield an ineffective overall clean if the cleaning agents are not applied in the correct sequence. Multiple stages of the chemistry sequences may be required to ensure a thorough cleaning.

The table below represents typical relative effectiveness of common cleaning solvents.

	Makeup of Deposit				
Type of Cleaning	**Organics**	**Iron**	**Copper**	**Silica**	**Hardness (Ca/Mg)**
Phosphate Boilout	Good	N/A	N/A	N/A	N/A
Permanganate	Good	N/A	N/A	N/A	N/A
Hydrochloric w/ABF*	N/A	Good	Poor	Medium	Good
HCl w/ABF & Thiourea	N/A	Good	Medium	Medium	Good
EDTA**	N/A	Good	Medium	Poor	Varies***
Citric Acid	N/A	Good****	Medium	Poor	Poor
Citric Acid with ABF	N/A	Good	Medium	Medium	Poor
Bromate	N/A	N/A	Good	N/A	N/A

Notes:
*ABF - Ammonium Bifluoride
**EDTA - Ethylenediaminetetraacetic Acid
***Effectiveness is dependent on the specific formulation.
****Addition of ammonia at a pH of 3.5 – 5.5 improves iron removal.

4.3.3.3 - *Efficacy (Dissolution) Testing*

The effectiveness of a selected cleaning strategy should be confirmed through laboratory testing. It may take several iterations, as the layering of deposits is not always easy to determine. The tube material for this laboratory testing should be a representative tube sample taken from the boiler. The laboratory chemistry tests should also emulate the time, temperature, conditions, and agitation anticipated for the cleaning.

4.3.3.4 - *Material/Solvent Compatibility & Corrosion Assessment*

Prior to the cleaning, evaluate the potential for corrosion of the boiler and contiguous components. Carefully assess whether there are any dead legs in the circuits that can come in contact with cleaning solutions. Determine whether and how they can be flushed and neutralized.

Sweetwater condensers often have tubes (stainless steel, nickel/copper alloys, etc.) that are incompatible with certain solvents. If the water and shell side of the sweetwater condenser contains these materials and cannot be adequately isolated from the boiler for the cleaning, alternative solvents may be required.

If the boiler is known to have significant waterside damage (including, but not limited to, hydrogen damage, SAC, pitting, FAC, cracking) additional solvent selection criteria may need to be considered.

4.3.3.5 - *Waste Disposal*

Regulations may vary by state, province, or country. Environmental considerations should be part of the planning process. This includes:

- Chemical approval of the proposed chemical cleaning process should be obtained as early as possible.

- Waste generated in the cleaning process can include metals removed from the waterside surfaces that are subject to environmental limits.

4.3.3.6 - *Pre-Engineering*

- **Engineering required.** Every job should be carefully planned from chemical selection to waste disposal. Aspects include ensuring that all circuits receive the proper circulation for the chemistry utilized. A means of isolating components that are not part of a cleaning must be properly designed. Prior to resuming operation, all non-vertical tubes and headers should be flushed to remove debris (refer to Section 4.3.6.1). Pay particular attention to tubes that contain restriction orifices and to headers that may contain baffles.

  There are numerous additional details that require careful design to ensure that the cleaning is effective and does not harm the unit.

- **Equipment requirements.** Most recovery boilers are not designed to be chemically cleaned. Therefore, additional temporary piping is typically required to complete the cleaning. In addition, chemical mixing headers, pumps, flow meters, and tanks are part of a chemical cleaning.

  Consideration for utilities including electrical, hot and cold water, steam, nitrogen, and instrument air must be reviewed.

- **Schedule**. Sufficient time must be allocated for the chemical cleaning including, but not limited to:
  - Installation and removal of temporary piping
  - Removal of internal drum components
  - Tie-in points to the boiler
  - Chemical cleaning stages
  - Inspection and flushing
  - Reinstallation of drum internals and pressure-parts
  - Hydrostatic tests
  - Iron removal and magnetite formation during start-up.

4.3.3.7 - *Perform Pre-Cleaning Piping Modifications & Associated Tasks*

Thorough drawings and detailed scopes of work decrease the chance of an error. Pressure testing temporary piping reduces the possibility of leaks during execution of the cleaning. Careful attention to insulating the boiler, closing dampers, and otherwise avoiding drafts through the flue gas path ensures that the chemistry will remain in its most effective temperature range.

Boiler instruments are rarely compatible with cleaning chemistry. Instrument tubing is susceptible to plugging from the suspended deposits. It is important to isolate or remove tubing-connected instruments prior to a cleaning. A means of verifying the level of chemistry within the boiler is part of pre-cleaning design.

All existing piping and valves that are to be subjected to cleaning chemicals should be carefully reviewed prior to the boiler shutdown to identify leaks. These leaks should be repaired prior to the cleaning.

Valves that need to be operated during the cleaning should be lubricated and stroked before the job; repair or replace valves as needed. Blowdown piping should be purged while the boiler is operating under pressure. Drain piping should be blown down while the boiler is under pressure without a fire or residual bed in the unit.

Note: Certain jurisdictions require registration of temporary valves and piping connected to a boiler. Review applicable regulatory requirements for any alterations to the boiler, including temporary tie-ins.

4.3.4 Chemical Cleaning Tasks

Safety is a foremost concern with any chemical cleaning. A well-planned cleaning includes informing operating personnel of the hazards and steps in the entire process well in advance of the actual start of the cleaning. It is important to ensure that all operating personnel in the area are familiar with the written plan, as they may need to enter the area to operate valves. Personnel not essential to the cleaning should be restricted from entering the area.

4.3.4.1 - *Water Block Circuit Isolation*

Verify that any circuit isolation achieved by means of a water block rather than blanks, valves, or bladders is in place before adding any cleaning chemicals to the boiler.

4.3.4.2 - *Verify Boiler Volume with Heating Water Fill*

Fill the boiler with hot water using temporary flow meters to determine the volumes of critical levels of the circuits to be cleaned. This volume can be used to validate the estimated chemical cleaning volumes determined in the planning stage. When preheating boiler tubes, do not exceed 100°F temperature rise.

Chemical Cleaning

4.3.4.3 - *Ensure Chemistry for the Stage is Correct*

Chemistry stages vary widely. Nevertheless, any chemical cleaning procedure should include the following:

- A procedure specific to the particular unit to be cleaned
- Verification of corrosion inhibitor
- Boiler metal temperatures specific for the chemistry
- Temperature, concentration, and estimated contact time for each stage
- Periodic testing of chemistry
- Circulation/agitation
- Rinse stage(s)
- Neutralization stages
- Neutralization of spent solution.

If stages are drained to the sewer, the draining must be maintained at a proper pH for that sewer. For example, draining acid to an alkaline sewer containing sulfides will liberate hydrogen sulfide gas. The neutralization solution should be of the appropriate concentration to facilitate adequate control.

4.3.4.4 - *Routine Testing of Cleaning Solution Samples*

A representative sample of the solution in the boiler should be routinely tested to monitor the progress of the cleaning. Testing consistent with the chemistry utilized for each cleaning stage should be outlined in the procedure.

4.3.4.5 - *Maintain Logs & Retain Solvent Samples*

Maintain detailed logs of all activity and testing. A composite sample of each stage must be collected and retained for calculating the amount of deposits removed and for environmental evaluation.

4.3.4.6 - *Be Prepared for Leaks*

Removing corrosion products in pits or crevices with significant underdeposit corrosion may reveal leaks. If these leaks are significant enough, a cleaning may need to be aborted. An adequately sized holding tank or neutralization plan should be in place to drain the partially spent solution. The potential to reclaim partially spent cleaning chemicals could be considered.

4.3.5 Post-Cleaning Tasks

4.3.5.1 - *Flush & Inspect Drums, Tubes & Headers*

A thorough flushing of drums, tubes, and headers is necessary to ensure that deposits loosened from tube surfaces do not redeposit once the boiler is put back into service. Water quality should be low TSS (total suspended solids), low pressure, and high volume. It may be necessary to remove bellyplates in drums. Careful inspection of the headers, drums, and horizontal tubes should follow. Photographs and/or videoscopes of accessible tubes, drums, and headers are highly recommended.

4.3.5.2 - *Start-Up Water Quality & Operating Practices*

Best practice is to ensure the boiler is started up as soon as possible following a chemical cleaning to minimize flash-rusting of cleaned surfaces. The start-up procedure for water chemistry and firing practices is designed to reestablish a magnetite layer as quickly as practical.

A start-up water quality procedure should be established in advance of the cleaning. It should be a collaboration between the mill, cleaning consultant, and water treatment subject matter experts. It is important to maintain water chemistry control and additional blowdown until targeted iron concentrations can be achieved. Topics that should be addressed in the written procedure include iron concentration, continuous blowdown, mud drum blowdowns if necessary, drum pressure, water chemistry, supplemental water treatment chemicals, venting and load schedule, and testing intervals.

4.3.6 SOPs

4.3.6.1 - *Deposit Weight Density -* DWD is a measurement of the weight of deposit material for a given surface area of the inside of a tube sample. For boiler waterside surfaces, this deposit is typically measured on the hot and cold sides of the tube.

ASTM D3483 provides three different test procedures for determining DWD. It is important to utilize the same procedure over time to ensure accurate comparison of successive tube DWD samples.

- ASTM D3483, Method A - Mechanical Removal by Scraper or Vibrating Tool
- ASTM D3483, Method B - Chemical Removal by Solvent
- ASTM D3483, Method C - Mechanical Removal by Glass Bead Blasting

Reference E: ASTM D3483

4.3.6.2 - *Tube Sample Deposit Analysis -* A tube sample extracted from a boiler should be analyzed for DWD and composition of the deposit. Morphology of the deposit and the overall condition of the inside of the tube surface can also be determined from a tube sample. All of these can provide valuable information about the condition of the internal tube surface.

Chemical Cleaning

The composition of the deposit will have a significant impact on the heat transfer characteristics and can impact the potential for underdeposit corrosion. Typical constituents of a deposit include, but are not limited to:

- Iron
- Copper
- Calcium
- Silica
- Phosphate
- Magnesium
- Manganese
- Aluminum
- Organic matter
- Sulfate
- Carbonate

The morphology is an indication of how the deposits layer on the waterside surface. The composition and morphology of the deposit will have an impact on chemical cleaning formulation and steps.

Visual inspection of the inside of the tube surface, after deposits have been removed, may indicate corrosion of the tube surface.

Guideline #1: It is recommended that a subject matter expert specify and plan a chemical cleaning. The subject matter expert should also oversee the clean. The importance of a subject matter expert becomes more critical as the complexity of the deposits increase.

Guideline #2: The use of a qualified cleaning contractor is recommended to ensure that a chemical cleaning is executed as designed.

Guideline #3: A chemical cleaning is a substantial time and cost commitment. When the decision is made to schedule a chemical cleaning, a mill should commit the time and resources to ensure that it is properly executed. If shortcuts are taken either in the design or execution of a cleaning, it is possible to harm the boiler, or result in an ineffectual clean.

Guideline #4: The decision to chemically clean an economizer should be made on a case-by-case basis with input from appropriate subject matter experts.

Guideline #5: Sweetwater condensers should receive careful consideration when planning a cleaning. Their relatively small tubes are prone to plug with deposits carried from the boiler circuitry. Review the metallurgy of the sweetwater condenser to ensure the compatibility with proposed cleaning solvents.

Guideline #6: A written procedure shall exist for all stages of the cleaning. This procedure should include SDSs for products brought on-site, safety protocols, required PPE, and a barricade plan.

Guideline #7: A detailed log shall be maintained during the chemical cleaning stages. At a minimum, it shall include the volumes of chemicals added, the volumes drained from a boiler, the concentration and/or amount of chemicals added, and solution temperatures.

Guideline #8: If any corrosion coupons were installed in the boiler during the chemical cleaning, they shall be removed prior to start-up.

Guideline #9: A written plan shall exist for start-up water quality and passivation assurance. It shall include dosage of boiler treatment chemicals, frequency of water tests, pH targets, target iron levels over time, blowdown levels, and contingency actions. Strong consideration should be given to maintaining a dedicated water test operator during start-up.

4.3.7 ESOPs

ESOPs should be established prior to the cleaning process to contend with unforeseen incidents that can occur during this process. These procedures vary by mill, but may include:

- Spills
    - Temporary piping failures
    - Containment failures
    - Overfilling of the boiler
    - Tank failures
- Emergency tanks
- Emergency drains
- Loss of site power/utilities/water/air
- Cross contamination
- Draining into incompatible sewers
- Leaks
- H_2S mitigation
- Chemical vapors/flammable gases
- Personnel exposure.

4.3.8 Monitoring

4.3.8.1 - *Deposit Weight Density* - Any tube collected for analysis should have the DWD determined.

Tube samples from the high heat zone in a furnace are typically utilized for analysis. Note that the highest deposits in a boiler are not always in the high heat zone of a furnace. For a cleaning to be successful, the tube sample should be taken from the most heavily scaled portion of the boiler.

Each boiler has unique firing characteristics and circulation patterns that impact where deposition will be highest. Boiler manufacturers, inspectors, and insurers may be able to provide input on the best locations to collect tube samples.

4.3.8.2 - *Deposit Composition Analysis* - Tube sample testing should include waterside deposit composition analysis. Deposit composition analysis can identify water chemistry issues that may not be noted in routine review of routine water chemistry data.

The deposit composition can be determined quantitatively by analyzing the elements by a variety of techniques including atomic absorption spectrophotometry, inductively coupled plasma (ICP), and X-ray fluorescence (XRF).

Organic composition is typically indicated by LOI. The amount of organic material in the sample is key information that is necessary when formulating a chemical cleaning. It is not always included when a tube is sent for analysis but should be specified.

4.3.8.3 - *Dissolution Test* - Laboratory should perform solvent tests to find the most effective chemical cleaning solvent(s) to be used. Any tube that is tested in a laboratory to determine effectiveness should include photographic documentation of the cleaning effectiveness.

4.3.8.4 - *Venting* - The boiler shall have an appropriately sized vent for the cleaning which should be routinely monitored during the cleaning for evidence of foaming.

4.3.8.5 - *Temporary Sight Glass* - A properly designed, temporary level indication should be in use to verify that boiler steam drum level remains within the procedural specification during cleaning stages.

4.3.8.6 - *Solvent Inhibitor Test* - The chemical cleaning contractor should perform a solvent inhibitor test approved and witnessed by the mill prior to introducing any mineral acid solvent to the boiler.

	4.3.8.7 - *Solvent Sampling* - Periodic solvent samples shall be collected from the boiler during cleaning stages to determine the concentrations of the solvent and amount of deposits removed. A composite drain sample shall be collected and analyzed for each solvent stage performed.

References:

A. Babcock & Wilcox Plant Service Bulletin PSB-44B Chemical Cleaning Guide, 1999.

B. *Valmet Technical Paper Series Paper Mill Boiler Chemical Cleaning - Why, When and How. September 2016.*

C. Teollisuuden Vesi *Chemical Cleaning Guidelines for New Kraft Recovery Boilers.* Technical Paper. May 2019.

D. ASME. Consensus on Best Tube Sampling Practices for Boilers and Nonnuclear Steam Generators. New York, NY: ASME, 2014. CRTD-Volume 103.

E. ASTM D3483-14 Standard Test Methods for Accumulation of Deposition in a Steam Generator Tube.

5.1 Condensate System

5.1.1 Design & Operational Considerations

System Overview

The condensate system is designed to reclaim heat and high purity water for reuse as boiler feedwater. An added benefit is the recycle of a portion of the condensate treatment chemicals into the boiler feedwater.

Basic System Flow Path

Condensate system designs vary depending on processes utilized at a mill and the system designer's preferences. Major sources of condensate include paper machine dryers, pulp dryers, digesters, evaporators, and turbine condensers. It is important to understand the individual mill design so that proper water chemistry is maintained throughout the system. The boundaries for the system start with the locations where steam is first condensed and end at the point of entry into the deaerator.

Basic System Component

Condensate Flash Tanks - The flash tank allows the temperature of condensate to be reduced while capturing the steam that flashes off in the process. This reduces the likelihood of flashing when condensate is returned to an atmospheric flash tank.

Condensate Dump Systems - The system diverts condensate based on contaminated water.

Turbine Condensers - A shell and tube heat exchanger that may be installed on the exhaust of a steam turbine generator, converting all steam routed through the turbine exhaust into condensate.

Steam Traps - Devices that segregate condensate from steam by either mechanical or thermostatic control.

Condensate Filters - An electromagnetic or cartridge filter. It is used in lieu of, or in conjunction with, condensate polishers. Removes particulate iron and a portion of copper in a condensate system.

Condensate Polishers - Resin-based ion exchange polishers may be used to remove both particulate and dissolved impurities. Units are typically limited to cation resin polishers due to typical condensate temperatures which exceed the capability of anion resin. Polishers may be used as stand-alone devices or following a magnetic filter.

Heat Exchangers - Condensate streams are frequently routed through heat exchangers for energy efficiency reasons.

Condensate Receivers - In most applications these are atmospheric tanks. They collect multiple individual condensate streams and integrate them into a single combined stream. The receivers may be preceded by a heat exchanger to collapse steam. In some mills makeup and condensate streams are blended in a common tank.

Paper Machine Condensate Separators & Vacuum Receivers - Condensate separators are designed to separate the steam and condensate from the paper machine dry end and typically operate under pressure. Condensate, or a mix of steam and condensate, is passed through these vessels. The level in these tanks is typically controlled by level control loops. One or more pumps on each tank maintains level and pumps the condensate back for reclaim. A vent on the top of the tank allows blow-through steam to go to a lower pressure dryer group or into a thermocompressor. Vacuum receivers are sometimes utilized on the lowest pressure steam in the paper machine.

Dryer Drainage Systems - These can either be rotating or stationary siphons within the dryer cans. They are designed to remove condensate and blow-through steam from the inside of the dryer cans.

Condensate Pump Seals - API 682 details over 30 pump seal designs; several of them are applicable to condensate pumps; of these, some have a potential for condensate contamination due to the source of seal water or a failure in a heat exchanger. Pump packing material also has a potential to contaminate condensate.

High Purity Water - Demineralized water, feedwater, and condensate that conforms to the specifications in TAPPI TIP 416-03, Table 1. This is generally water with a conductivity of less than 5 µs/cm.

5.1.2 Chemical Treatment & Control Considerations

Water/Steam Purity Impact Assessment

Condensate can serve as a conduit for contaminants, such as liquor, iron, starch, fiber, caustic, acid, copper, hardness, and others, to reach the boiler and deposit within the boiler tubes. Condensate typically contains some oxygen and, under low pH conditions (< 8.3), carbon dioxide. The concentration of oxygen and/or CO_2 can be localized within the system or widespread. Component venting practices can impact the concentration levels in various system components. The resulting corrosion not only affects the condensate piping itself, but has the potential to transport iron into the recovery boiler.

In all cases, consult with water treatment subject matter experts for water treatment program recommendations.

Condensate System

Key Chemical Control Variables

There are a number of factors that can influence condensate chemical treatment program and control. The program should be selected based upon:

Mechanical Factors -

- **Presence of copper alloys for equipment in the steam or condensate systems.** If copper is utilized for equipment in the steam or condensate systems, particular focus must be placed on pH control and the levels of specific contaminants that may react with copper.

- **Deaerator performance.** Sub-optimal condition of the deaerator can/will cause economizer corrosion. In addition, the gases that remain in the feedwater could carry through to the steam system, consuming scavengers and amines in the condensate system. The level of gases, specifically CO_2, that remain in the feedwater system may be influenced by the pH of the deaerated water. The presence of oxygen will tend to drive the corrosion rates of the feedwater metallurgy higher when oxygen is present in a low pH environment.

- **Air inleakage.** Any portion of the condensate system vented to atmosphere or operating under a vacuum has a potential to draw in air and increase corrosion. This corrosion can transport red iron to the recovery boiler.

Design & Operational Factors -

- **Boiler feedwater water quality.** Any design modification to the pre-treatment or external treatment system (equipment or procedures) can create a discernable and sustainable change in feedwater quality which will carry through to the steam and condensate. It may require a change in treatment selection and/or control to meet corresponding ASME guidelines based upon the conditions encountered.

- **Condensate system complexity.** In systems where there are a number of operating pressures and/or extensive piping, consideration should be given to treatment chemistry selection. In most paper mill applications, a blend of amines is utilized to elevate the pH throughout the condensate system.

- **Condensate return rates.** A sustained change in the proportion of return condensate will change the amount of treatment chemicals that are recycled back to the feedwater system. Any change in the ratio of condensate returns to makeup water will alter the feedwater chemistry.

- **Boiler operating pressure.** The volatilization and decomposition of some amine products present in the boiler water will be a function of boiler operating pressure.

- **Boiler internal tube condition.** Overall economizer and boiler waterside tube surface conditions as determined by DWD and deposit composition could merit a change in the condensate treatment program.

- **ASME guidelines for the feedwater and boiler water.**

- **Site-specific water quality guidelines.**

  In all cases, consult water treatment subject matter experts when a change in water quality has taken place or when a change in the makeup of the mechanical condensate treatment processing system(s) is being considered.

Other Factors that Affect Chemical Treatment Program Selection & Performance -

- **Presence of known deposits within the recovery boiler circuitry.** The presence of deposits in boiler circuits and headers increases the concerns regarding the condensate treatment program selection.

- **Historical information.** Collection and consolidation of condensate quality data and condensate system upset incidents can be beneficial for historical review of recovery boiler operations.

  Note: In all cases, provide the water treatment subject matter expert with a historical overview of past water treatment-related anomalies.

Program Selection Options - Program selection is dependent on factors such as feedwater quality, condensate system design, boiler steam temperature, and boiler deposit history. Current available treatment options for condensate systems are:

- Neutralizing amines
- Filming amines
- Oxygen scavengers/metal passivators.

Treatment can consist of a combination of the above options.

In all cases, provide your water treatment subject matter experts with a historical overview of past water treatment-related anomalies.

Chemical Feed & Condensate Monitoring Practices -

- Care must be taken in selecting chemical feed points and delivery systems. Improperly designed chemical delivery systems can compromise the ability to control water chemistry.

- Intermittent or highly variable flows from condensate streams that have their own corrosion treatment injection, such as filming amines, should be reviewed to ensure that the treatment does not overfeed or underfeed during periods of variable condensate flow.

- Condensate sampling points should be located in close proximity to the source of potential contamination to allow for the condensate dump systems to function in a timely manner and to provide accurate/representative sample monitoring results. An example of suggested sample points can be found in TAPPI TIPs 0416-03 "Water quality and monitoring requirements for paper mill boilers operating with high purity feedwater" and 0416-14 "Water quality and monitoring requirements for paper mill boilers operating with softened makeup water".

- Condensate sample streams shall have proper flow to ensure that they are representative of the water returning from a given source. The temperature of the samples should be conditioned to 25°C. Variation from this temperature will affect turbidity, particle count, and pH meters. The sample stream shall flow continuously. It should be noted that restrictions in sample flow will alter the response time in automated dump systems and can generate non-representative data.

  Any stream servicing an instrument that could potentially be contaminated with liquor has a potential to plug or foul. Best practice would be an insertion-style probe in a large diameter continuous flowing stream.

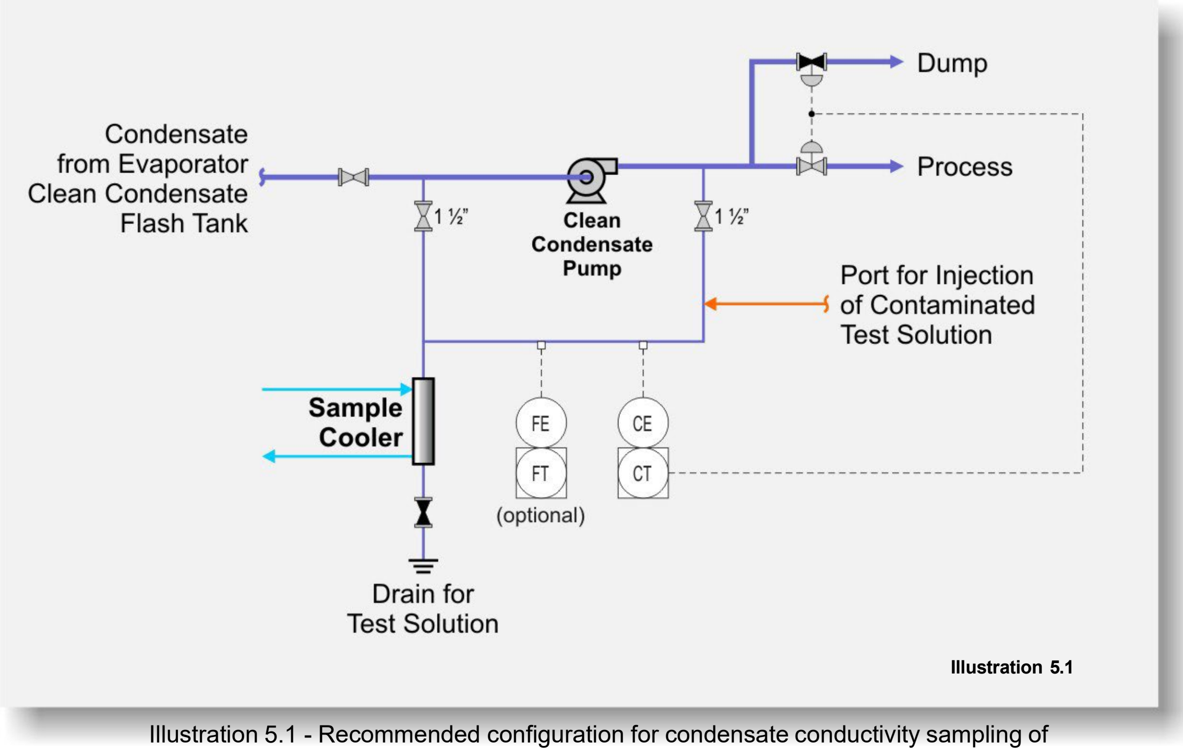


Illustration 5.1 - Recommended configuration for condensate conductivity sampling of a condensate stream with the potential for liquor contamination.

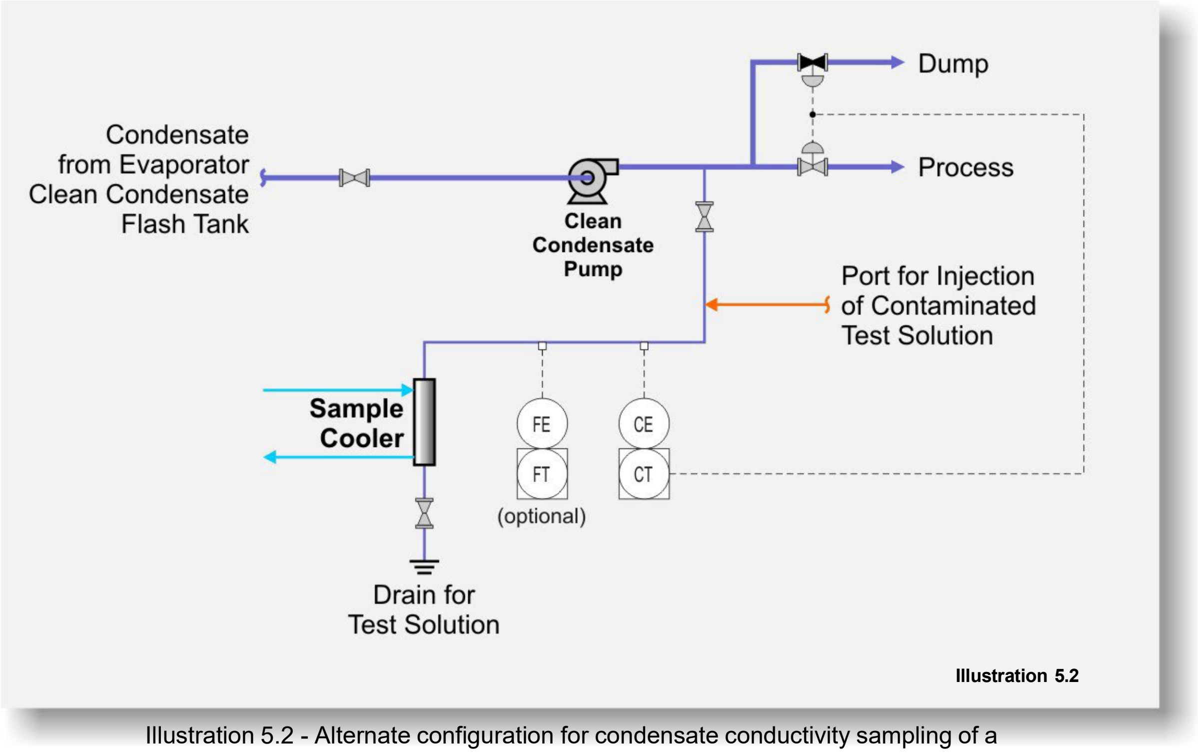


Illustration 5.2 - Alternate configuration for condensate conductivity sampling of a condensate stream with the potential for liquor contamination.

- Instruments to protect feedwater from condensate upsets should be located to provide adequate time for dump or divert valves to actuate and prevent contamination of all condensate.

- Sample streams should be located to enable testing of condensate while it is being dumped or diverted in order to determine acceptability for reintroduction into the condensate collection system.

- Flow monitoring is recommended for all sample streams:
  - Flow measurements that are alarmed in the DCS are the preferred method of verifying flow.
  - On recirculation loops, if flow meters are not utilized, the sample line should be opened to sewer and the positioning of the conductivity meter should be such that dump valves will actuate in a timely manner even if the recirculation loop is plugged and the flow is only traveling through the sample line to sewer.
  - If the alternate sample system is utilized as shown in Illustration 5.2, in the absence of an alarmed flow measurement, there should be a managed system for visually verifying flow on a routine basis.

5.1.3 Key Maintenance Practices & Protocols

System Reliability Impact Assessment

A properly maintained condensate system will prevent oxygen and CO_2 contamination. It will also prevent many process contamination events.

Inspection Techniques

Qualified individuals should perform visual piping and condenser inspections in conjunction with appropriate nondestructive examination. In addition, qualified individuals should perform polisher resin analysis, spark testing of liners, instrumentation PMs and calibrations of key instruments, control valve PMs, check valve PMs, and steam trap PMs.

Inspection Frequency

The frequency of inspection for the piping and check valves is mill location specific. It will typically correlate with a steam system cold outage.

Piping inspections will depend on the piping materials, corrosion history, water quality, and chemical treatment efficacy.

Condensers are a common source of raw water infiltration. Pressure testing and/or other nondestructive testing frequencies should be established.

A representative condensate polisher resin sample should be analyzed as history and performance dictates, but should be done not more than three years after installation/rebedding.

Lined polisher bodies should be spark tested at a frequency consistent with the ASME required interval for the pressure vessel. Laterals should be inspected when the vessel is open for spark testing. A visual inspection should be performed on laterals any time all of the resin is removed from the unit.

All test instrumentation and their associated collection/dump valves should be functionally tested weekly.

Benchtop and field instrumentation should receive regular PMs at an established interval to ensure reliable operation.

5.1.4 SOPs

5.1.4.1 - *SOP - Returning Condensate from Processes Returning to Service* - For processes such as paper machines or evaporators that are returning to service, the mill should establish a procedure to field-verify adequate condensate sample flow and quality prior to bringing that source back into the collection stream.

Condensate System

	5.1.4.2 - *SOP - Condensate Testing -* Condensate samples should be tested at intervals not to exceed six hours. Intervals between tests can be longer where continuous monitoring is utilized. Manual entry test data should be retained in accordance with mill document retention policies. Tests should include pH, conductivity, hardness, and iron. Silica may be a suitable surrogate for hardness to detect mill water contamination.
	5.1.4.3 - *SOP - Condensate pH -* Condensate in systems where copper is present in some portion of the metallurgy should be maintained at a pH appropriate for this metallurgy to minimize corrosion potential. If no copper is present in the condensate system, a wider recommended pH range will typically be permitted. Regardless of metallurgy, an established SOP should indicate acceptable ranges for condensate pH.
	5.1.4.4 - *SOP - Condensate Outside Normal Control Boundaries -* All condensate streams tested should include an SOP for all test results outside specified control ranges.
	5.1.4.5 - *SOP - Polisher Operation -* A written procedure should exist to define operation, backwash, and regeneration intervals and criteria.
	5.1.4.6 - *SOP - Double Block & Bleed -* A written procedure should exist to explain proper operation of double block and bleed steamout lines in all departments where steam is utilized to purge or clear a process line.
	5.1.4.7 - SOP - *pH Meter Calibration, Use & Storage* - A written procedure should exist for all departments testing the pH of condensate streams with a benchtop unit. The procedure should detail the calibration procedure, sample test protocol including sample temperature range, and proper storage of the pH probe.

5.1.5 ESOPs

5.1.5.1 - *ESOP - Condensate Emergency Conditions* - All of these ESOPs should include the following elements:

- A troubleshooting decision tree that delineates action steps to be taken
- A list of likely contaminant sources for the given excursion
- A call list of upstream condensate suppliers to contact for troubleshooting contamination questions
- A list of water treatment subject matter experts to be contacted in the event of an emergency
- A list of feedwater consumers downstream to be contacted
- Which condensate samples are to be retained for future analysis
- Which water tests should be performed at increased frequency
- Specification of test intervals for specified parameters
- A description of water support system component bypass capabilities (if any exist).

5.1.5.2 - *ESOP - High/Low pH* - An ESOP should exist for high and low pH excursions in condensate. In addition to the common elements, this ESOP should include:

- A check and confirmation of condensate conductivity relative to normal operating range.

5.1.5.3 - *ESOP - High Condensate Conductivity* - An ESOP should exist for high condensate conductivity. In addition to the common elements, this ESOP should include:

- A check and confirmation of pH relative to normal operating range
- A check of cation conductivity relative to normal operating range.

5.1.5.4 - *ESOP - Condensate Silica* - If silica is tested, an ESOP should exist for silica excursions.

5.1.5.5 - *ESOP - Condensate Hardness Excursions* - If hardness is tested, an ESOP should exist for hardness excursions.

5.1.5.6 - *ESOP - High Condensate Iron Levels* - An ESOP should exist for high condensate iron levels.

5.1.5.7 - *ESOP - Starch Contamination* - For mills that cook starch, an ESOP for identifying starch contamination is recommended. Establish a chemical oxygen demand (COD) baseline test to compare against upset conditions (depressed boiler water pH and increased boiler water conductivity with no apparent feedwater contamination).

5.1.6 Monitoring

5.1.6.1 - *Monitoring - Representative Samples* - Samples shall be representative of the source. Sample lag time should be minimized to prevent contaminants from traveling past the dump valves. Sample velocities should be sufficient to maintain particulate contaminants in suspension (5 ft/s is recommended). Maintain adequate sample bottle supply to collect and retain samples in the event of an upset. Refer to ASME CRTD - Vol. 81 Consensus on Operating Practices for the Sampling and Monitoring of Feedwater and Boiler Water Chemistry in Modern Industrial Boilers for specifics on proper sampling technique.

5.1.6.2 - *Monitoring - Evaporator Conductivity* - Evaporator condensate streams shall be equipped with conductivity meters that are alarmed in a control room.

These meters shall be tied to automatic condensate divert valves located downstream of the meter. A redundant conductivity meter is recommended for each evaporator stream. Configuration of evaporator clean condensate stream meters should be in-line, in a continuously flowing recirculating side stream (see Illustration 5.1), or a probe upstream of a sample cooler.

5.1.6.3 - *Monitoring - Evaporator Conductivity Sample Stream Flow* - Evaporation condensate sample streams should have means of verifying flow.

- Flow measurements that are alarmed in the DCS are the preferred method of verifying flow.
- On recirculation loops, if flow meters are not utilized, the sample line should be opened to sewer and the positioning of the conductivity meter should be such that dump valves will actuate in a timely manner even if the recirculation loop is plugged and the flow is only traveling through the sample line to sewer.
- If the alternate system is utilized as shown in Illustration 5.2, in the absence of an alarmed flow measurement there should be a managed system for visually verifying flow on a routine basis.

5.1.6.4 - *Monitoring - Other Major Condensate Streams Conductivity* - Major condensate streams should be equipped with online conductivity meters.

Online conductivity meters are recommended on every condensate storage tank or on the combined condensate return line.

Any condensate stream with the potential for contamination that imparts conductivity and could shut down the recovery boiler shall have an online conductivity meter and an automatic dump system at some point between the contaminant and the recovery boiler feedwater.

5.1.6.5 - *Monitoring - Turbidity -* Online turbidity meters/particle monitors are recommended for all paper machine condensate streams to trend and alarm iron throw levels. Time-based dumping with manual verification, while not as effective as continuous monitoring, is an acceptable alternative. Where meters are used, they should be interlocked to condensate dump valves, especially if there is no downstream filtering or polishing of the condensate. Sample lag time is particularly important in this application.

5.1.6.6 - *Monitoring - Condensate Sample Locations -* All steam traps immediately upstream of any direct steam injection processes should have a sample collection tap to facilitate troubleshooting in the event of a process upset.

5.1.6.7 - *Monitoring - pH of High Purity Streams -* High purity streams should have a dedicated laboratory pH probe. Calibration according to manufacturer's recommendations.

5.1.7 Inspection/Documentation

5.1.7.1 - *Inspection/Documentation - Presence of Copper Alloys -* The mill should consult with their water treatment subject matter experts for proper control parameters when copper alloys are present.

5.1.7.2 - *Inspection/Documentation - Surface Condensers -* Turbine condensers should be pressure and/or nondestructively tested to ensure cooling water is not entering the condensate.

5.1.7.3 - *Inspection/Documentation - Evaporators -* Any equipment in the black liquor evaporation train that uses live steam should be hydro-tested with every major shutdown to ensure that the potential for black liquor contamination is minimized.

5.1.7.4 - *Inspection/Documentation - Black Liquor Heaters -* Black liquor heaters should be hydro-tested or nondestructively tested at an interval not to exceed five years.

5.1.7.5 - *Inspection/Documentation - Flash Tanks -* Any flash tanks with vacuum break lines should be inspected to ensure that the lines do not extend to sewers where the pipe has the potential to be submerged. Drains should not be positioned such that they could be submerged in a sewer, as this creates the potential to draw sewer streams back into the system if subjected to vacuum.

Condensate System

5.1.7.6 - *Inspection/Documentation - Check Valves in Steam Systems* - Any process where steam is directly injected into a process should have a minimum of one check valve. Check valves should be inspected for proper function at designated intervals (to be determined by the mill). It is recommended that check valve systems be designed such that they can be visually inspected, borescoped, acoustically tested, or functionally tested.

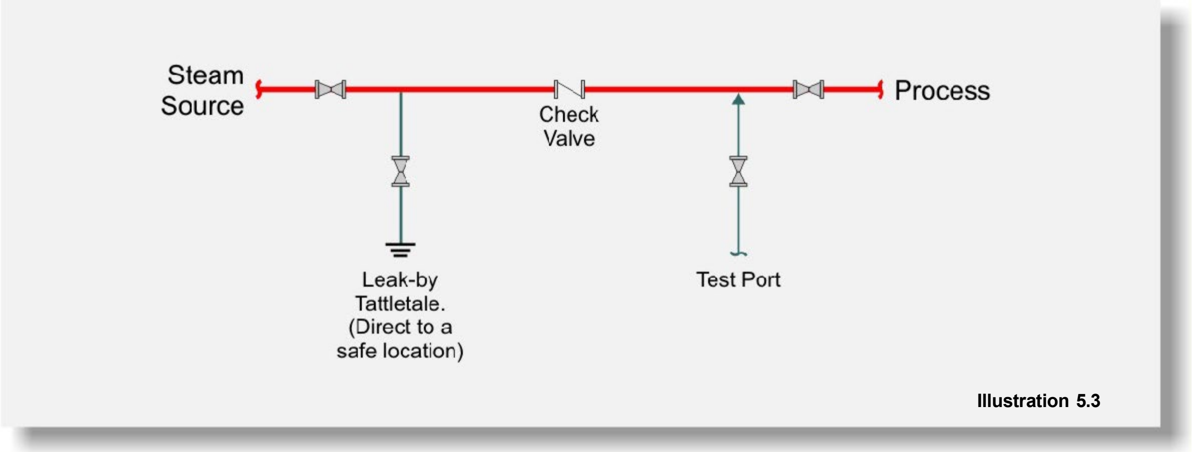


Illustration 5.3 - Example of a check valve functional verification system in a non-pressurized application. Pressurized applications may eliminate the test port.

5.1.7.7 - *Inspection/Documentation - Polisher Resin* - If equipped with condensate polishers, samples of condensate resin should be drawn every three years and analyzed. Resin volume, specifications, and manufacturer should be recorded. Resin should be extracted such that the sample is a representation of the entire resin bed for a given polisher. Note the condition (exhausted, regenerated, or mid-run) of the resin upon extraction.

5.1.7.8 - *Inspection/Documentation - Polisher Liner* - Each polisher equipped with liners should be spark tested at intervals not to exceed ASME intervals for testing the pressure vessel.

5.1.7.9 - *Inspection/Documentation - Condensate Dump/Divert Valves* - Condensate dump and divert valves should be exercised as a part of regular documented condensate conductivity functional testing. Functional testing should include:

- Introduction of a conductivity contaminant to the conductivity element
- Visual verification of dump valve operation, including time to open and close
- Verification of control room alarm or valve state change on operator panel.

5.1.7.10 - *Inspection/Documentation - Condensate System Flow Diagram* - A one page drawing showing all dump systems should exist from the receiver to termination in the dump system. Drawing should be verified annually for accuracy.

6.0 Sampling & Testing Protocols

6.1.1 Design & Operational Considerations

System Overview

Accurate assessment of water and steam quality must be performed in a timely manner. This is critical to ensure that the water and steam circuits remain free of harmful deposits and corrosion.

Basic System Flow Path

Sampling and testing encompasses the entire water cycle, including makeup water and condensate systems.

ASME CRTD-81 Consensus Operating Practices for Sampling & Monitoring of Feedwater/Boiler Water Chemistry provides recommended sample point locations for soft water makeup systems (Figure 1 and Table 1) and for high purity makeup systems (Figure 2 and Table 2). These diagrams and associated tables should be consulted for typical arrangements of each respective system.

Definitions

Boiler Water Treatment Chemical Concentration - Tracer molecules, boiler treatment chemistry, water mass balances, or some combination of these can be utilized to adjust chemical feed concentrations, blowdown levels, or provide early indication of a possible leak in a boiler circuit.

Methods for testing the concentrations are varied, including, but not limited to, online or laboratory photometric meters, conductivity, pH, or titration.

Conductivity Measurement - Conductivity measurement may be either a specific conductivity measurement or a cation conductivity measurement.

> *Specific Conductivity -* Specific conductivity is a direct measurement of the total conductance of the water sample.
>
> *Conductivity After Cation Exchange (CACE) -* CACE measures steam purity after a cation exchange column. CACE is typically used in high purity applications to minimize the impact of certain water treatment chemicals, such as organic and amine-based components, on the conductivity reading. In some cases, membranes may be used in lieu of cation exchange columns.

Core Sampler - A device capable of obtaining a representative sample column of resin, carbon, media or sludge. Examples of this include a grain thief or a Sludge Judge™.

Critical Instrument - Any instrument that monitors for a water-borne contaminant with the potential to lead to a boiler shutdown.

Sampling & Testing Protocols

Dissolved Oxygen Testing - Dissolved oxygen meters, oxidation/reduction potential (ORP) meters, and ampoule test kits (in varying degrees of precision) are all methods utilized to determine the dissolved oxygen levels in boiler feedwater.

Hardness Testing - Hardness is an archaic, but commonly used term. It refers to the total concentration of divalent cations including calcium, magnesium, strontium, and barium.

Two commonly utilized test methods for hardness are titration and spectrophotometric. In practical use, the spectrophotometric method can detect lower levels of hardness than titrations. Tests are typically manual, but can be continuously monitored. The operating pressure of the boiler may determine the test method required for a specific application.

High Purity Water - Demineralized water, feedwater, and condensate that conforms to the specifications in TAPPI TIP 416-03, Table 1. This is generally water with a conductivity of less than 5 µs/cm.

Jar Testing - A simulation of process conditions in a laboratory environment to assess the efficacy of treatment chemicals typically using a multi-beaker variable-speed mixing apparatus. In a water filtration plant, jar tests are a method to determine optimum chemical dosages for clarification and settling.

Iron Testing - Iron can be an important indicator of contamination or corrosion that may be occurring within a water or steam system. Excessive iron in feedwater can contribute to an increase in waterside tube deposits in a boiler. Within a water system, iron is commonly present in the soluble form as ferrous (Fe^{+2}) or insoluble form as ferric (Fe^{+3}), which is the oxidized, particulate form.

Ferrous (Fe^{+2}) - Soluble iron.

Ferric Oxides:

Hematite (Fe_2O_3) - Insoluble iron oxide (red iron) associated with the oxidation of ferrous (soluble) iron.

Magnetite (Fe_3O_4) - Insoluble iron oxide (black iron). Self-passivation of iron formed at high temperature under alkaline, oxygen free conditions (The Schikorr Reaction).

Iron may be detected chemically, optically, or by filtration methods (see ASTM D1068-15 for additional information):

Chemical testing is typically performed with a spectrophotometer and can detect ferrous or total iron (ferrous, ferric iron, and particulate) after digestion.

Ferrous iron (Fe^{2+}) testing is used to assess active corrosion in the form of soluble iron.

Optical monitoring provides continuous online indication of contamination, which may include iron; it is performed with particle monitors or turbidity meters. Some particle monitors can provide particle size distribution.

Membrane filtration (Millipore or equivalent) for particulate iron is used on condensate, feedwater, and boiler water samples. The membrane filter used in boiler water and condensate is a 0.45 µm cellulose acetate or cellulose nitrate pad. The color of this pad after one liter of water is passed through it is compared to a color chart to indicate the relative iron oxide (particulate) level in the water. (See B&W Method Iron Membrane Comparison Chart.)

Off-Site Laboratory Tests - Water from throughout the mill can be collected for testing at off-site facilities to determine a multitude of compounds and elements in the water. These typically have value when tested at a predetermined frequency (most commonly every 3 - 6 months) to allow assessment of long-term and seasonal trends.

pH Measurement - pH is the negative log of the hydrogen ion concentration, representing the relative acidity or alkalinity of a sample. This measurement is typically obtained using an electronic instrument equipped with an amperometric probe.

The pH of water is dependent on the temperature of a water sample. Water must be at 25°C (77°F) to accurately read pH. If this temperature cannot be achieved, a temperature correction chart should be utilized. See ASTM D1293-99 (Standard Measurement for pH of Water) for laboratory measurements, and ASTM D5464-16 (Standard Test Method for pH Measurement of Water of Low Conductivity) for more information. Some pH meters have temperature correction factors that can be programmed; this is called the solution temperature coefficient (STC). Automatic temperature compensation (ATC) found in most bench-top meters is not the same as STC; ATC simply compensates for changes in electronic circuit resistance due to temperature.

Ionic strength may be boosted with a neutral salt to stabilize pH (see ASTM D1293-99 for more information).

Resin Tests - Resin testing can determine the overall condition of resin beads as well as the amount of fouling present, so cleaning or replacement can be scheduled. A representative regenerated sample is necessary for accurate interpretation of the results.

Sample Conditioning - Many process samples are either in the steam phase, are at temperatures that would flash at standard pressures, or would be too warm to handle safely. These samples are cooled and/or condensed for analysis. High pressure sample stations will include a pressure reducing valve (PRV) to allow samples to be safely tested.

Sample Tubing - Tubing is used to transport a representative portion of a process to an instrument, laboratory, or convenient location to collect the water. Materials of construction, diameter of tubing, flow path, the amount of cooling that occurs in this tubing, and the length of the tubing run all affect the accuracy and/or timeliness of the sample. Sample lines for boiler water should be small diameter stainless steel tubing from the drum to the sample station, as carbon steel pipe typically is too large in diameter to provide the turbulent flow necessary for a representative sample.

Silica Testing - Silica may be present in water as an ion (reactive) or a colloid (non-reactive). Silica ion concentration (SiO_2^-) can be tested online, which is typical in a demineralizer plant, or by manual tests, which are more commonly utilized in a boiler water test lab. Colloidal silica is not detected by a reactive silica test but may become reactive after exposure to high temperatures inside a recovery boiler. If silica is detected in boiler water, but is not detected in feedwater, colloidal silica should be suspected.

Note that other impurities can interfere with silica tests. This includes iron, sulfides, phosphate over 50 ppm, and highly buffered solutions.

Silica can additionally be tested in steam, which may be necessary to ensure compliance with turbine manufacturer specifications. Steam silica testing is outside the scope of this document.

Silt Density Index (SDI) - An empirical test used to characterize the fouling potential of a reverse osmosis (RO) feedwater stream. The test is based on the plugging rate of a 0.45 µm filter using a constant 30 psig (207 kPag) feed pressure for a specified period. See ASTM D4189-07 (2014) Standard Measurement for SDI of Water.

Sodium Testing - Sodium is measured in makeup water to ensure the performance of water purification systems. Sodium is also measured in steam to detect carryover of boiler water.

Sodium analyzers are used after cation exchange vessels or after mixed bed demineralizers to indicate that a unit may be nearing exhaustion.

Sodium is additionally measured in steam from the boiler to validate steam purity and quality. See ASTM D1066-18e1 for steam purity measurement.

Spectrophotometer - A spectrophotometer is an instrument that functions by measuring the refractive index of light at a particular wavelength passing through a water sample that has been properly conditioned for the parameter being tested. It is typically used to measure phosphate, oxygen scavenger, iron, silica, and hardness levels.

Starch - Starch is used in the paper manufacturing process. It is cooked and heated with steam, introducing the possibility of boiler system contamination. The temperature of boiler water will hydrolyze starch, causing a low pH condition. There are no commonly available methods for detecting low levels of starch in condensate.

A focus on prevention of starch intrusion should take preference over attempting to detect starch that may enter a system. High levels of starch can be detected by turbidity meters or particle counters.

Steam Sample Taps - A sample point where saturated or superheater steam is collected; it is typically designed to provide a representative sample of the steam at that point in the process.

Proper extraction and handling of steam is critical to obtain a representative sample. Isokinetic sampling is the preferred method for extracting a steam sample. Long sample tubing runs can negatively impact the accuracy of results. Refer to ASTM D1066-18e1 and ASME PTC 19.11 for more information.

Turbidity Meters/Particle Counters - Online turbidity meters and particle counters are utilized to assess levels of suspended particulate in condensate, such as iron or other contaminants. Starch can sometimes be detected in condensate streams with these meters.

Water Sample Taps - A sample point where water is collected (including, but not limited to, softened water, demineralized water, RO water, feedwater, boiler water, or condensate); it is typically designed to provide a representative sample of water at that point in the process.

6.1.2 Sample Conditioning & Control Considerations

Water/Steam Sampling Accuracy Assessment

Test instrumentation providing inaccurate data or sample points providing non-representative water can result in improper water chemistry control or a false sense of security with respect to water quality. Proper design, instrument calibration, and lab techniques all play a role in ensuring the accuracy of test data.

Key Control Variables

There are several factors that can influence the quality of the sample being analyzed. Sample points and conditioning equipment should be selected based upon:

Design & Operational Factors -

- **Steam sample system designs.** Refer to ASME and ASTM guidelines when designing a steam sampling system.
    - *A Practical Guide to Avoiding Steam Purity Problems in the Industrial Plant*, ASME CRTD-35
    - *Steam and Water Sampling, Conditioning, and Analysis in the Power Cycle*, ASME PTC 19.11
    - *Standard Practice for Sampling Steam*, ASTM D1066-18e1
    - *Consensus Operating Practices for Sampling & Monitoring of Feedwater/Boiler Water Chemistry*, ASME CRTD-81.

    A properly conditioned representative sample is critical to obtaining meaningful data.

    The steam sample should be condensed as soon as possible to prevent solids from depositing along tubing.

    Isokinetic sampling is more important on saturated steam lines than superheated steam lines.

    Consideration for materials of construction of the tubing should include the likelihood that material will adhere to or leach from the walls; stainless steel is typically a material of choice.

- **Sample conditioning.** A representative water or steam sample must meet several parameters simultaneously: proper flow rate, lag time, and sample temperature.
  - **Sample flows.** To achieve a representative sample for particulate iron testing, flow should be laminar in the sample tubing (4 - 6 ft/s or 1.2 - 1.8 m/s) based on the largest diameter of the sample line. Low sample flow rates can lead to undesirable lag times and solids deposition inside the tubing. Tubing size will play a role in the capacity of the sample cooler required. At laminar flow, larger diameter tubing will require correspondingly larger cooling capacity.

    Not all sample lines will have continuous flow. For samples that are used intermittently, depending on the parameter to be tested, it may be necessary to purge three sample line volumes to ensure that accumulated sediment does not impact the test results. (*Consensus Operating Practices for Sampling & Monitoring of Feedwater/Boiler Water Chemistry*, ASME CRTD-81).
  - **Online instrumentation placement.** Online instruments or probes should be as close to the sample extraction point as possible.
  - **Sample cooling.** Coolers should be capable of conditioning a sample to 25°C (77°F) at appropriate flow rates. Additional or larger sample coolers in series may be required in some cases. Temperature specifications are most critical for pH.
  - Sample coolers can contaminate a sample and fittings can leak air into the process.
- **Manifolded online instrumentation.** Economic constraints may dictate that one online instrument be utilized for several samples. This will require automatic or manual switching valves with the instrument in a central location.
  - **Control loops & alarms.** Careful consideration of lag and purge times should be taken into account when using one instrument to measure multiple process streams.
  - **Sample purging volumes.** Purge volumes should be calculated to ensure no cross-contamination.
  - **Switching valves.** Failed or leaking switching valves introduce the possibility of cross-contamination.
  - **Continuous flow.** A manifold system should allow for continuous flow of all samples whether they are being measured or not.
- **Boiler water sample extraction from a steam drum.** Boiler water is typically measured by taking a sample of boiler continuous blowdown water. The orientation of holes in the continuous blowdown pipe relative to the holes in the feedwater supply pipe is typically specified by the boiler manufacturer. If the holes in the continuous blowdown or feedwater line are improperly oriented, it could result in feedwater dilution of the blowdown, yielding an inaccurate assessment of actual waterside conditions.

- **Timely measurement.** If a high purity water sample is left in an open container or in contact with air, it will absorb CO_2, which acidifies the sample and lowers the pH. Absorbed CO_2 will also increase conductivity in high purity water.
- **Labware.** Clean labware is necessary for accurate test results. This is particularly important for hardness testing. Glass should not be used for ultra-low hardness or silica testing.
- **Hardness Testing Contamination.** Dedicated plasticware, pour-through processing equipment, and clean laboratory environments are necessary for precision ultra-low hardness test results.

6.1.3 Key Maintenance Practices & Protocols

System Reliability Impact Assessment

Properly maintained equipment increases confidence in data and can minimize delays in responding to upset conditions.

Maintenance & Calibration

Maintenance of instrumentation requires strict adherence to calibration and storage procedures. In particular, pH meters have specific ranges of calibration solutions that should be utilized. These reference solutions have a shelf life. pH probes also have storage requirements that are important for accurate measurement; they should not be stored in demineralized water. Before every shift, benchtop pH meters should be validated against two reference solutions on either side of the expected pH of the sample.

Critical instruments should have an adequate inventory of spare parts or complete replacement units.

Consideration should be given for alarm notification of critical instruments that fail or exceed their programmed range.

Calibration Frequency

All test instrumentation should be calibrated per OEM specifications at recommended intervals or more frequently.

In-line instrumentation should have a preventative maintenance calibration interval.

6.1.4 SOPs

6.1.4.1 - *SOP - pH Testing* - A sample should be tested for pH immediately. Also note that boiler water chemistry is based on a sample conditioned to 25°C (77°F). *Standard Test Method for pH Measurement of Water of Low Conductivity,* ASTM D5464-16 notes that online pH measurement is preferred to benchtop testing; online measurement is required in certain locations within a recovery boiler water system (see BLRBAC Instrumentation Checklist and Classification Guide for Instruments and Control Systems).

6.1.4.2 - *SOP - pH Meter Calibration, Use & Storage* - A written procedure should exist for benchtop-pH testing. The procedure should detail the calibration procedure, calibration interval, sample test protocol including sample temperature range and proper storage of the pH probe between sampling. The probe should not be stored in high purity water, because the water etches the metal in the sensor. Typically, it is stored in a pH storage solution specified in the equipment user's manual.

Reference solutions and reagents should be maintained within their shelf life. Reagents stored in open containers should be renewed more frequently.

6.1.4.3 - *SOP - pH of High Purity Water Samples* - High purity water samples shall have a dedicated laboratory pH probe. Calibrate according to manufacturer's recommendations.

6.1.4.4 - *SOP - pH Temperature Correction* - If proper temperature cannot be achieved, a temperature correction chart shall be utilized to compensate for deviation from 25°C (77°F) target temperatures. Refer to the instrument manufacturer's documentation for an appropriate correction chart. If a correction chart is not available from the manufacturer, consult your water treatment representative for guidance on creating a site-specific chart for your meter.

A sample collected and sealed without the possibility of air ingress can be cooled in a water bath and tested at a later time as an alternative to temperature correction.

6.1.4.5 - *SOP - Critical Instrument Sample Flows* - An SOP shall exist to ensure the required continuous sample flow rate is present for any online water system-critical instrument. A critical instrument is one that monitors for a contaminant that has the potential to lead to a boiler shutdown. The verification of this flow rate is required at a predetermined interval. Best practice is to utilize an alarmed online flow measuring device on a preventative maintenance schedule.

If a critical online instrument is used for automatic control of boiler water treatment chemicals or cycles of concentration in a boiler, this instrument shall have an online flow measurement device with appropriate alarms.

6.1.4.6 - *SOP - Cross Validation of Readings* - An SOP should exist to split a sample and test with a different instrument and different reagent (where applicable) when a measurement is suspect.

Sampling & Testing Protocols

6.1.4.7 - *SOP - Resin Extraction -* A procedure for proper resin sampling technique should be adhered to when extracting resin for analysis. Broken beads and dirty beads can classify within a vessel. If a resin sample is not an even representation of the resin bed, the analysis results will not reflect the true condition of the resin. A core sample is recommended. Resin should only be extracted from vessels with a minimum of 15 cm (6") of water above the top of the bed.

Packed-bed vessels require extraction of media during an external backwash.

6.1.4.8 - *SOP - Hardness Testing -* Feedwater hardness limitations are based upon boiler operating pressure and the processing capabilities of the makeup water support systems. An SOP shall be in place that addresses hardness test protocols.

There are two hardness test methods that are typically employed:

- Colorimetric/titration low level limit of detection (100 ppb)
- Spectrophotometric ultra-low level (20 ppb).

Colorimetric Titration Test - Due to limitations in level of detection and differences in visual interpretation, the colorimetric titration test should only be used with softened water makeup.

- The lowest practical level of detection is 100 ppb. If this method is employed, the results as recorded by the operator should be routinely validated utilizing a methodology that has a <100 ppb level of detection.

- A step-change in routine test results should be addressed immediately.

Spectrophotometric Analysis - The ultra-low hardness test is the preferred method to test for hardness in high purity feedwater systems. Due to variability in the results obtained in the field, site-specific control boundaries should be assigned and monitored. Focus should be given to any step change in hardness levels.

6.1.4.9 - *SOP - Iron or Copper Testing -* Iron or copper testing requires very precise control of collection and processing conditions. For accurate results, the sample line must have appropriate flow, purge volumes, and sample velocity to ensure that particulate iron or copper does not deposit inside the sample line.

6.1.4.10 - *SOP - Reagents -* A best practice is to have a periodic checklist for quantities and expiration dates on all reagents used for water chemistry tests. Alternately, an SOP for testing could include a line item to verify expiration dates on reagents. All reagents should be stored according to manufacturer specifications.

6.1.4.11 - *SOP - Water Test Specifications -* All water tests shall have limits based on ASME water quality specifications for the operating pressure of the unit. Mills shall determine appropriate action levels and processes for addressing excursions.

6.1.4.12 - *SOP - Silica Testing -* Labware and online analyzer components used in silica testing can become etched from citric acid reagents. This will cause a false high reading. Labware and other consumable components should be changed on a regular schedule.

The instrument manufacturer's test procedure should be incorporated into the SOP for accurate test results.

6.1.4.13 - *SOP - Management of Change -* Alterations to critical instrument alarm setpoints, flows, or replacement components must follow the Management of Change (MOC) policies for that facility.

6.1.5 ESOPs

6.1.5.1 - *ESOP - Critical Instrument Failure -* An ESOP shall exist to cover remedial actions needed in the event of a critical instrument failure. This ESOP should include:

- The backup means of obtaining the necessary test data. This may include expediting reagents as they could be depleted sooner than expected due to increased manual testing.
- The frequency for backup manual testing, if a replacement is not immediately available.
- Having the instrument promptly repaired or replaced.
- Any jumpers or bypass of critical instrumentation shall be performed in accordance with a mill's jumper policies.

6.1.5.2 - *ESOP - Water Upset Sample Retention -* The mill should have a procedure to retain several water samples in the event of a water quality upset. This would include maintaining an inventory of sample bottles for collection of these samples.

6.1.5.3 - *ESOP - Reagent Availability -* The mill should have an ESOP for a low or no reagent inventory.

6.1.6 Inspection/Documentation

6.1.6.1 - *Inspection/Documentation - Sample Coolers -* Periodic testing of sample coolers for internal leaks of cooling water into the test stream is recommended. Test by isolating the sample stream inlet while maintaining cooling water flow.

6.1.6.2 - *Inspection/Documentation - Test Result Retention -* Manual entry test data and online data should be retained in accordance with mill document retention policies.

Sampling & Testing Protocols

	6.1.6.3 - *Inspection/Documentation - Calibration Records* - Instrument calibration records should be retained in accordance with mill document retention records.
	6.1.6.4 - *Inspection/Documentation - SOPs* - SOPs and ESOPs shall be reviewed annually or per mill policy.

Section 3.1 - Deaerator Systems

Item	Description	Control Measure	I	II	Comments	Compliant (Y/N)
3.1.4.1	Deaerator Operation	SOP		x	Start-up, shutdown, operation, and upset response	
3.1.5.1	Storage Tank Temperature	Monitoring		x	Verify that the water is within 5^{o}F of saturation	
3.1.5.2	Steam Pressure	Monitoring	x		Low pressure indication and alarm	
3.1.5.3	Storage Tank Level	Monitoring	x		Includes low level and high level alarms	
3.1.6.1	Pressure Vessel Inspections	Inspection/Documentation		x	Conform to NACE SP0590 requirements	
3.1.6.2	Trays	Inspection/Documentation		x	Inspect the tray and traybox at cold outages	
3.1.6.3	Spray Nozzles	Inspection/Documentation		x	Inspect for tension and obstructions	
3.1.6.4	Steam Check Valve	Inspection/Documentation		x	Inspect at mill-determined frequency	
3.1.6.5	Feedwater Chemical Delivery Systems	Inspection/Documentation		x	Feed scavenger through a quill into the dropleg or aways from tank walls	
3.1.6.6	Compatibility of Chemicals	Inspection/Documentation		x	Verify compatibility of chemicals going into a single feed point	

Section 3.2 - Feedwater Pump & Piping Systems

Item	Description	Control Measure	I	II	Comments	Compliant (Y/N)
3.2.4.1	Feedwater Iron Levels	SOP	x		To include ASME guidelines, test type, frequency, and responsible party	
3.2.5.1	Feedwater Dissolved Oxygen Ingress	ESOP	x		Specifies response to oxygen contamination and where to look	
3.2.5.2	Feedwater Low/High pH	ESOP	x			
3.2.5.3	Feedwater High Conductivity	ESOP	x		Include predetermined threshold for removing boiler from service	
3.2.5.4	Feedwater Hardness Ingress	ESOP	x			
3.2.6.1	Feedwater Conductivity w/Alarm Setpoint	Monitoring	x			
3.2.6.2	Feedwater pH	Monitoring	x			
3.2.6.3	Feedwater Oxygen Testing & Sampling	Monitoring		x	High pressure sample cooling systems on feedwater pump inlet & discharge	
3.2.7.1	Feedwater Flow-Accelerated Corrosion	Inspection/Documentation		x	Maintain routine nondestructive test program for feedwater piping	
3.2.7.2	Feedwater Pump Mechanical Seals or Packing Glands	Inspection/Documentation	x		Document source of seal water, maintenance practice and frequency	
3.2.7.3	Feedwater Chemical Delivery Systems	Inspection/Documentation		x	Update drawings of feed point annually or when water treatment changes	
3.2.7.4	Copper Metallurgy	Inspection/Documentation		x	Survey boiler water system for potential sources of copper	
3.2.7.5	Feedwater Oxygen Analyzers	Inspection/Documentation	x		If utilized, analyzers shall have a checklist for maintenance and calibration	

Section 3.3 - Feedwater Steam Attemperation Systems

Item	Description		I	II	Comments	Compliant (Y/N)
3.3.5.1	Attemperator Water Quality	ESOP	x		Action steps for contamination or for loss of primary attemperation source	
3.3.6.1	Sweetwater Condenser Water Sampling	Monitoring		x	Have capability to test condensed steam on shell side outlet	
3.3.6.2	Attemperator Water Conductivity	Monitoring		x	Water that exceeds 12µs/cm should be scrutinized	
3.3.6.3	Attemperator Feedwater Cation Conductivity	Monitoring		x	Recommended if feedwater is the primary source of attemperation	
3.3.6.4	Sweetwater Condenser Water Quality	Monitoring		x		
3.3.7.1	Attemperator Metallurgical Considerations	Inspection/Documentation		x	Review metallurgical compatibility for the application when purchasing	
3.3.7.2	Annual Review of Attemperator Drawings	Inspection/Documentation		x	Includes backup attemperation water supply system	
3.3.7.3	Prohibited Chemistry - Non-Volatile Chemicals	Inspection/Documentation	x			

3.3.7.4	Change in Attemperation Water Source	Inspection/Documentation		x	Management of Change document in the event of a change in supply	
3.3.7.5	Attemperator Inspection Guideline	Inspection/Documentation		x	Formal inspection protocol for mechanical integrity	
3.3.7.6	Attemperator Checklist	Inspection/Documentation		x	Routine review of control valve output and steam outlet temperature	

Section 3.4 - Blowdown Heat Recovery Systems

Item	Description		I	II	Comments	Compliant (Y/N)
3.4.5.1	Steam Contamination from the Continuous Blowdown System	ESOP		x	High tank level can carry over into flash steam system	
3.4.5.2	Processed Water Contamination of Continuous Blowdown System	ESOP		x	If heat exchangers are utilized on blowdown water	
3.4.6.1	FW Conductivity Elevation & the Continuous Blowdown System	Monitoring		x	CBD as part of FW contamination ESOP (heat exchanger or high level in tank)	
3.4.7.1	Continuous Blowdown Tank Heat Exchanger	Inspection/Documentation		x	If pressures allow CBD to contaminate process water, instrument to protect	
3.4.7.2	Continuous Blowdown Tank Level Control	Inspection/Documentation	x		Automatic level control of flash tank is required	
3.4.7.3	Continuous Blowdown Piping	Inspection/Documentation		x	Routine part of operator walkdown	
3.4.7.4	Blowdown Piping	Inspection/Documentation		x	Periodic check for thinning	

Section 4.1 - Economizer Systems

Item	Description		I	II	Comments	Compliant (Y/N)
4.1.4.1	Economizer Iron Monitoring (In/Out)	SOP		x	Sampling protocols for iron in and out of economizer	
4.1.6.1	Economizer Iron & Oxygen Testing	Monitoring		x	Iron can be tested in different oxidative states	
4.1.6.2	Economizer Sample Coolers	Monitoring		x	Pre- and post-economizer sample points	
4.1.7.1	Economizer Chemical Feed Point	Inspection/Documentation	x		Check compatibility of boiler water chemicals added before economizer	
4.1.7.2	Economizer Inspection Tube Sampling	Inspection/Documentation		x	Samples shall also be inspected for pitting - establish a sampling frequency	
4.1.7.3	Economizer Borescope Inspection	Inspection/Documentation		x	When there is an open circuit due to maintenance or repairs	
4.1.7.4	Economizer Root Cause Analysis	Inspection/Documentation		x	In the event of a tube failure	

Section 4.2 - Drum, Tube & Header Circuitry

Item	Description		I	II	Comments	Compliant (Y/N)
4.2.4.1	Front & Back Filling the Boiler	SOP		x	Superheater not to be filled from the steam drum - all-volatile chemicals only	
4.2.4.2	Boiler Water Testing	SOP	x		Test interval of 4 - 6 hours; longer if continuous instrumentation present. **Test pH, conductivity, silica, treatment chemical concentration (alkalinity for low pressure)**	
4.2.4.3	Boiler Water Chemistry Outside Normal Control Boundaries	SOP	x		SOPs for pH, silica, iron, conductivity, chem treatment, or alkalinity	
4.2.4.4	Hardness Testing	SOP	x		Ultra low is preferred for high purity feedwater systems	
4.2.5.1	Boiler Water High/Low pH Conditions	ESOP	x			
4.2.5.2	High Boiler Water pH Excursion - Coordinated Phosphate	ESOP			Include a predetermined pH level and time for taking boiler off-line	
4.2.5.3	Low Boiler Water pH Excursion - Coordinated pH Programs	ESOP			ESOP to include several steps including threshold for boiler off-line	
4.2.5.4	High Boiler Water Silica	ESOP				
4.2.5.5	Feedwater Hardness Excursions Affecting Boiler Water Chemistry	ESOP			Boiler water pH could be suppressed by a hardness excursion	
4.2.5.6	High FW Iron Levels Elevating Boiler Water Iron Levels - Baseline Iron Data	ESOP	x		Requires routine testing to establish a baseline for this ESOP	
4.2.5.7	RB Leak Detection	ESOP		x	ESOP for validating alarm states for either mass balance or acoustic system	
4.2.6.1	Feedwater Inlet Temperature to the Drum	Monitoring	x		Required where applicable instrumentation installed	
4.2.6.2	Boiler Lower Furnace Temperature	Monitoring		x	Useful in determining tube surface conditions	

4.2.6.3	Saturated Steam Purity	Monitoring		x	On-line sodium analyzers recommended	
4.2.6.4	Cameras & Fiber Optics	Monitoring		x	Use opportunities with tube removal to inspect open circuits	
4.2.6.5	Boiler Water Iron	Monitoring	x		Boiler water iron test every 8 - 12 hours in most cases	
4.2.6.6	Boiler Water Silica Monitoring (Colloidal Silica)	Monitoring		x	Test silica no less than every 8 - 12 hours	
4.2.7.1	Steam Drum Blowdown Line Orientation	Inspection/Documentation	x		Typical orientation is straight up	
4.2.7.2	Boiler Waterside Condition	Inspection/Documentation	x		Document DWDs and deposit analysis	
4.2.7.3	Boiler Water Treatment Sample Points	Inspection/Documentation		x	Annually update water test sample points on the boiler and other systems	
4.2.7.4	Boiler Water Treatment Feed Points	Inspection/Documentation		x	Annually update water treatment feed point documentation	
4.2.7.5	Boiler Visual Inspection Checklist	Inspection/Documentation		x	A boiler inspection checklist on file for all routine shutdowns.	
4.2.7.6	Boiler Visual Inspection Protocols	Inspection/Documentation		x	Inspection should be backed up by NDE and tube samples	
4.2.7.7	Boiler NDE Program	Inspection/Documentation		x	NDE should be trended for regression analysis	
4.2.7.8	Boiler Tube Deposit Weight Density	Inspection/Documentation		x	Obtain DWDs from tube samples to aid chemical cleaning protocols	
4.2.7.9	Boiler Steam Drum	Inspection/Documentation		x	Regular inspection minimum checklist	
4.2.7.10	Boiler Feedwater Chemical Injection Quill	Inspection/Documentation		x	NDE of downstream piping recommended at major outages	
4.2.7.11	Mud Drum	Inspection/Documentation		x	Regular inspection minimum checklist	
4.2.7.12	Boiler Headers	Inspection/Documentation		x	Inspect for sludge/debris following major work or chemical cleaning	
4.2.7.13	Boiler Furnace	Inspection/Documentation		x	Regular inspection minimum checklist	
4.2.7.14	Boiler Near Drum/Mud Drum Furnace	Inspection/Documentation		x	Consider where applicable	
4.2.7.15	Root Cause Analysis	Inspection/Documentation		x	Consider where applicable	

Section 4.3 - Chemical Cleaning

Item	Description		I	II	Comments	Compliant (Y/N)
4.3.6.1	Deposit Weight Density	SOP		x	Use a consistent method; note that different OEMs specify different methods	
4.3.6.2	Tube Sample Deposit Analysis	SOP		x	Composition of a deposit is critical for planning the chemistry and stages of a cleaning	
4.3.8.1	Deposit Weight Density	Monitoring		x	High heat zones are recommended for tubes to be extracted for DWD	
4.3.8.2	Deposit Composition Analysis	Monitoring		x	Organic content is not always included, but should be specified	
4.3.8.3	Dissolution Test	Monitoring		x	Cleaning a tube sample in a laboratory validates cleaning chemistry to be used	
4.3.8.4	Venting	Monitoring	x		Must be properly sized	
4.3.8.5	Temporary Sight Glass	Monitoring		x		
4.3.8.6	Solvent Inhibitor Test	Monitoring		x	Ensures that the solvent will not attack metal surfaces	
4.3.8.7	Solvent Sampling	Monitoring	x		Every stage of a clean must be routinely tested and composite drain samples collected	

Section 5.1 - Condensate Systems

Item	Description		I	II	Comments	Compliant (Y/N)
5.1.4.1	Returning Condensate from Processes Returning to Service	SOP	x		Establish a procedure to verify quality before collecting a condensate source	
5.1.4.2	Condensate Testing	SOP	x		Intervals not to exceed 6 hours. Should include pH, cond., hardness, iron	
5.1.4.3	Condensate pH	SOP	x		Establish an acceptable range with consideration for the presence of copper	
5.1.4.4	Condensate Outside Normal Control Boundaries	SOP	x		Procedures and actions for test results outside of specified control ranges	
5.1.4.5	Polisher Operation	SOP	x		Procedure includes operation, backwash, and regeneration intervals/criteria	
5.1.4.6	Double Block & Bleed	SOP	x		Written procedure for proper operation	

5.1.4.7	pH Meter Calibration, Use & Storage	SOP	x		If utilizing a bench-top device include temperature ranges and probe storage	
5.1.5.1	Condensate Emergency Conditions	ESOP	x		Recommended elements to include in any condensate ESOP	
5.1.5.2	High/Low pH	ESOP	x		For both high and low pH excursions. Include cross-check of conductivity	
5.1.5.3	High Condensate Conductivity	ESOP	x		For high conductivity. Include cross-check of pH and cation conductivity	
5.1.5.4	Condensate Silica	ESOP	x		If silica is tested, maintain an ESOP for excursions	
5.1.5.5	Condensate Hardness Excursions	ESOP	x		If hardness is tested, maintain an ESOP for excursions	
5.1.5.6	High Condensate Iron Levels	ESOP	x			
5.1.5.7	Starch Contamination	ESOP	x		For facilities that cook starch, establish an ESOP for identifying contamination	
5.1.6.1	Representative Samples	Monitoring	x		Ensure proper velocities and lag time. Retain samples during upset conditions	
5.1.6.2	Evaporator Conductivity	Monitoring	x		Conductivity meters alarmed in a control room. Must have auto-divert valves.	
5.1.6.3	Evaporator Conductivity Sample Stream Flow	Monitoring	x		Flow meters are preferred to routine visual verification	
5.1.6.4	Other Major Condensate Streams Conductivity	Monitoring	x		Critical lines require auto-divert valves; meters recommended on storage tanks.	
5.1.6.5	Turbidity	Monitoring	x		For all paper machine returns, interlocked to auto-divert valves.	
5.1.6.6	Condensate Sample Locations	Monitoring	x		Sample collection point at steam traps ahead of direct steam injection	
5.1.6.7	pH of High Purity Streams	Monitoring	x		Dedicated laboratory instrument for high-purity streams	
5.1.7.1	Presence of Copper Alloys	Inspection/Documentation	x		Establish proper parameters when copper alloys are present	
5.1.7.2	Surface Condensers	Inspection/Documentation	x		Pressure or IRIS test turbine condensers	
5.1.7.3	Evaporators	Inspection/Documentation	x		Hydro test at major shutdowns	
5.1.7.4	Black Liquor Heaters	Inspection/Documentation	x		Hydro test or IRIS test at intervals not to exceed 5 years	
5.1.7.5	Flash Tanks	Inspection/Documentation	x		Vacuum breaks, drains should not extend below liquid levels in sewers	
5.1.7.6	Check Valves in Steam Systems	Inspection/Documentation	x		Minimum of one check valve for direct steam injection. Test at regular intervals	
5.1.7.7	Polisher Resin	Inspection/Documentation	x		Representative sample for analysis every three years	
5.1.7.8	Polisher Liner	Inspection/Documentation	x		Spark test at ASME intervals, if equipped with liners	
5.1.7.9	Condensate Dump/Divert Valves	Inspection/Documentation	x		Exercise valves as part of routine functional testing; visually verify operation	
5.1.7.10	Condensate System Flow Diagram	Inspection/Documentation	x		Update annually; ensure all dump systems are included in the drawing	

Section 6.1 - Sampling & Testing Protocols

Item	Description		I	II	Comments	Compliant (Y/N)
6.1.4.1	pH Testing	SOP		x	Sample should be tested immediately upon collection and conditioned to 25°C.	
6.1.4.2	pH Meter Calibration, Use & Storage	SOP		x	A written procedure should exist for benchtop pH meter testing.	
6.1.4.3	pH of High Purity Water Samples	SOP	x		High purity water samples shall have a dedicated laboratory pH probe.	
6.1.4.4	pH Temperature Correction	SOP	x		A temperature correction chart shall be utilized if 25°C samples cannot be achieved.	
6.1.4.5	Critical Instrument Sample Flows	SOP	x		A means to verify sample flow for critical process streams shall be alarmed or verified	
6.1.4.6	Cross Validation of Readings	SOP		x	A procedure to split samples and test elsewhere if the reading is suspect should exist.	
6.1.4.7	Resin Extraction	SOP		x	Have an SOP to achieve a representative sample when extracting for sampling.	
6.1.4.8	Hardness Testing	SOP		x	Hardness testing should be appropriate for the purity of the feedwater	
6.1.4.9	Iron or Copper Testing	SOP		x	Proper sample flow is necessary to achieve representative measurement of Cu or Fe	
6.1.4.10	Reagents	SOP		x	A checklist to verify inventory of reagents should be developed.	

6.1.4.11	Water Test Specifications	SOP	x		Water test limits shall comply with ASME specifications for the unit operating pressure.	
6.1.4.12	Silica Testing	SOP		x	Labware for silica testing should be replaced routinely.	
6.1.4.13	Management of Change	SOP	x		MOC shall exist for changing critical instrument alarm setpoints, flows, components	
6.1.5.1	Critical Instrument Failure	ESOP	x		A plan shall exist for remedial action in the event of a critical instrument failure.	
6.1.5.2	Water Upset Sample Retention	ESOP		x	Have collections bottles and a procedure to retain water immediately upon an upset.	
6.1.5.3	Reagent Availability	ESOP		x	Have a plan to immediately restock reagents if they are low or missing.	
6.1.6.1	Sample Coolers	Inspection/Documentation		x	Coolers should be periodically tested for leakage.	
6.1.6.2	Test Result Retention	Inspection/Documentation		x	Maintain water test results in accordance with mill document retention policies.	
6.1.6.3	Calibration Records	Inspection/Documentation		x	Maintain instrument calibration records in accordance with document retention policies.	
6.1.6.4	SOPs	Inspection/Documentation	x		Review SOPs and ESOPs annually.	

Classification I - Required for Normal Operation
Classification II - Recommended Where Applicable