ENCLOSURE (1)

2022 OWNER'S ACTIVITY REPORT FOR CC1R26

FORM OAR-1 OWNER'S ACTIVITY REPORT

Report Number CC1R26

Plant Calvert Cliffs Nuclear Power Plant - 1550 Calvert Cliffs Parkway Lusby, MD 20657

Unit No. 1 (if applicable) Commercial Service Date May 8, 1975 Refueling Outage Number CC1R26

Current Inspection Interval ISI = Fifth Inspection Interval / CISI = Third Inspection Interval
(1st, 2nd, 3rd, 4th, other)

Current Inspection Period First Inspection Period (ISI and Containment ISI)
(1st, 2nd, 3rd)

Edition and Addenda of Section XI applicable to the Inspection Plans ASME Section XI 2013 Edition

Date and Revision of Inspection Plans ER-CA-330-1001, Rev. 3 (1/5/2022), Rev. 2 (12/17/2020), Rev. 1 (1/30/2020)

Edition and Addenda of Section XI applicable to repair/replacement activities, if different than the inspection plans Same as above

Code Cases used: N-532-5, N-639, N-716-1, N-722-1, N-733, N-729-6, N-770-5, N-823-1, N-885

CERTIFICATE OF CONFORMANCE

I certify that (a) the statements made in this report are correct; (b) the examinations and tests, meet the Inspection Plan as required by the ASME Code, Section XI; and (c) the repair/replacement activities and evaluations supporting the completion of CC1R26 (refueling outage number) conform to the requirements of Section XI

Signed Travis Lefton, ISI Program Owner (Owner or Owner's designee. Title) Date 5/26/2022

CERTIFICATE OF INSERVICE INSPECTION

I, the undersigned, holding a valid commission issued by the National Board of Boiler and Pressure Vessel Inspectors and employed by The Hartford Steam Boiler Inspection and Insurance Company have inspected the items described in this Owner's Activity Report, and state that, to the best of my knowledge and belief, the Owner has performed all activities represented by this report in accordance with the requirements of Section XI.

By signing this certificate neither the Inspector nor his employer makes any warranty, expressed or implied concerning the repair/replacement activities and evaluation described in this report. Furthermore, neither the Inspector nor his employer shall be liable in any manner for any personal injury or property damage or a loss of any kind arising from or connected with this inspection.

(Inspector's Signature) Commissions 15722 AI, N, I, R (National Board Number and Endorsement)

Date 05/26/2022

TABLE 1

ITEMS WITH FLAWS OR RELEVANT CONDITIONS THAT REQUIRED EVALUATION FOR CONTINUED SERVICE

Examination Category	Examination Item Number	Item Description	Evaluation Description
E-G	E8.10	Containment Pedestal Moisture Barriers	ECP-22-000077 evaluation of containment liner due to missing moisture barrier in accordance with 10 CFR 50.55a(b)(2)(ix)(A)(2). See Attachment 1 for evaluation.
B-G-2	B7.70	Valve 1SI128 Bolting	ECP-22-000081 1SI128 evaluation of bolting due to presence of boric acid residue. Condition acceptable as is, no evidence of base material wastage observed
B-G-2	B7.70	Valve 1MOV624 Bolting	ECP-22-000082 1MOV624 evaluation of bolting due to presence of boric acid residue. Condition acceptable as is, no evidence of base material wastage observed
B-G-2	B7.70	Valve 1MOV652 Bolting	ECP-22-000083 1MOV652 evaluation of bolting due to presence of boric acid residue. Condition acceptable as is, no evidence of base material wastage observed
B-G-2	B7.70	Valve 1SI144 Bolting	ECP-22-000084 1SI144 evaluation of bolting due to presence of boric acid residue. Condition acceptable as is, no evidence of base material wastage observed
B-G-2	B7.70	Valve 1SI134 Bolting	ECP-22-000085 1SI134 evaluation of bolting due to presence of boric acid residue. Condition acceptable as is, no evidence of base material wastage observed
B-G-1	B6.180	RCP 11A, 12A, and 12B Bolting	ECP-22-000086 RCP 11A, 12A, and 12B evaluation of bolting due to presence of boric acid residue. Condition acceptable as is, no evidence of base material wastage observed
B-E	B4.30	Reactor Vessel Head	ECP-22-000087 evaluation of reactor vessel head penetration 5 and 6 based on bare metal visual examination results. Condition acceptable as is, no evidence of base material wastage observed

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5/26

TABLE 2

ABSTRACT OF REPAIR/REPLACEMENT ACTIVITIES REQUIRED FOR CONTINUED SERVICE

Code Class	Item Description	Description Of Work	Date Completed	Repair/Replacement Plan Number
1	Mechanical Nozzle Seal Assembly (MNSA)	Replace Grafoil seal and hardware for leaking MNSA. Replacement complete SAT. No identified leakage.	2/26/2022	2022-1-005 2022-1-006 2022-1-007 2022-1-008
1	Relief Valve	Replace RV with Spare. Traceability of RV could not be verified. Reference IR 04502105	2/16/2022	2021-1-043
3	Spool Piece	Repair leak upstream of 1RV-5212 on spool 18"-LJ-1-1075-15	2/5/2021	2021-1-006

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Reason for Evaluation:
As identified in IR 4477900, a general visual examination of the containment moisture barrier was performed, and it was identified that the pedestal moisture barriers are degraded. Moisture has been identified in the crevice created by some of the degraded seals. With the presence of moisture, corrosion and pitting/thinning of the containment liner is possible. The areas being evaluated are shown in attachment 2. The areas of most concern, and used for inputs to this evaluation, are the northeast side of pedestal 1, the south corner of pedestal 2, and the southwest corner of pedestal 6.

An evaluation will be performed to determine the acceptability of the containment liner. This evaluation is being performed in accordance with ASME Section XI Subsections IWE-2500(d), IWE-3512, and IWE-3122.3 and to meet the requirements of 10 CFR 50.55a(b)(2)(ix)(A)(2), specifically:

i. A description of the type and estimated extent of degradation, and the conditions that led to the degradation
ii. An evaluation of each area, and the result of the evaluation
iii. A description of necessary corrective actions

Age related degradation of the containment pedestal moisture barriers has led to conditions that allow water intrusion into the inaccessible area which could come into contact with and result in corrosion of the underlying containment liner. Due to various leaks and spills that have resulted in water on the 10' elevation throughout the service life, signs of moisture were detected in the inaccessible areas in several locations that exhibit moisture barrier degradation. Subsequent removal of the degraded moisture barriers revealed the presence of water on the liner.

This evaluation is completed as a Technical Evaluation per CC-AA-309-101 step 1.1.1 item 1 as this evaluation is used for "evaluating a degraded or non-conforming conditions to ensure that the condition is within the design basis of the plant."

This evaluation will consist of two parts. The first part will evaluate the loads on the containment liner to establish a reasonable lower-bound liner thickness which would provide margin to still be able to perform the liner's safety related function as a leak tight membrane and fission product barrier during a LOCA or other accident scenario. The second part will be to determine a conservative acceptable corrosion rate and time frame; this will be compared to historical industry corrosion rates.

Rev 001 Addresses editorial comments.

Detailed Evaluation of Problem/Changes:
System description:
The reactor building consists of a concrete wall with a carbon steel liner on the inside. The concrete provides the structural function of the reactor building. The liner provides a safety related leak tight membrane. The liner is ¼" carbon steel plate attached to the concrete by an angle grid system. Near the bottom of the reactor building the liner on the wall transitions smoothly to the floor. The transition is constructed from a ½" thick plate rolled to a 12" radius and welded to the wall and floor liners. The horizontal liner at the bottom of the reactor building is located at elevation 8'-6" (Ref 1). A concrete slab has been placed on top of the liner, creating the reactor building floor at an elevation of 10' (Ref 1). The majority of the horizontal liner is placed directly on the outer prestressed, post tensioned concrete foundation of the reactor building and is thus not subject to bending or shear loads. The transition section is placed on a compressible material, a compressible material is also located above the transition between the transition liner and the concrete floor (Ref 3). The transition section of the liner would be subject to bending loads during a postulated accident scenario. The degraded areas of the moisture barrier are all located at equipment pedestals where the liner is sandwiched between the concrete shell of the reactor building and the concrete floor and thus has no freedom to move or be subjected to bending or shear loads as a result of LOCA pressure.

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As stated in UFSAR Section 5.5

> *"The liner plate was designed to function only as a leak tight membrane. It does not serve as a structural member to resist the tension loads from internally applied pressure which may result from any credible accident.*
> *Structural integrity of the containment is maintained by the prestressed, post tensioned concrete. Since the principal applied stress to the liner plate membrane is in compression and no significant applied tension stressed were expected from internal pressure loading."*

Despite the fact that the liner is not credited to resist the internal pressure as a result of a LOCA, an analysis will be performed on the liner as though it was subject to the LOCA Reactor Building pressure to evaluate its capability to function as a leak tight membrane.

The primary load on the liner would be pressure as a result of a LOCA. The Reactor building is designed to withstand an internal pressure of 50 psig during this accident scenario (ref 6). The area of concern is directly below the moisture barrier, as such there is no concrete load on top of the area.

During the 2020 refueling outage an Integrated Leak Rate Test (ILRT) was performed on unit 1 containment with satisfactory results, showing that the containment liner is capable of meeting the design basis LOCA accident peak pressure requirements of 10 CFR Appendix J Option B to Part 50. Following the ILRT there was no indication of issues with the liner.

Margin for Remaining Localized Thickness Evaluation:
When the potentially corroded areas of liner are subjected to a LOCA, the minimum thickness of the liner capable of being leak-tight during a LOCA is to be evaluated. This evaluation and methodology is not intended to replace the original liner construction analysis as described in the UFSAR. The liner itself is not the pressure vessel designed to contain the 50 psi LOCA pressure as the liner is not the containment structure. This evaluation is to verify the liner has sufficient margin to perform the leak-tight function. To be conservative, and for the purposes of this evaluation, the area of possible liner degradation will be performed by treating it as a flat plate with fixed supports on all 4 sides and no support directly beneath the area of interest. Evaluated as a flat plate fixed on 4 sides is appropriate as the plate is held rigidly in place by the concrete shell and concrete floor.

- Liner material is ASTM A-36 carbon steel (Ref 6); the minimum tensile strength is 58 ksi, and the minimum yield strength is 36 ksi.
- The maximum allowable tensile strength for A-36 CS is 16600 psi at 300 F per ASME Section II (Ref 8). The value of 300F was chosen as the maximum expected concrete surface temperature during a LOCA per UFSAR section 1.2.3 is 276F.
- It is assumed that the area of interest of possible liner degradation is 24" long and 1" wide. The length is a conservative value based on inspections performed of the degraded moisture barriers during the 2022 refueling outage. The results of the inspection can be viewed in the CC-AA-106-1001Attachment 2 (can be viewed in FCMS). The 1" width is conservative based on the nominal moisture barrier width of ½" per Ref 3.
- Attachment 1 of illustrates the minimum acceptable liner thickness for the potentially corroded area using code allowable stress = tmin = **0.039 inch**

The established margin minimum thickness of the corroded area could degrade from uniform general corrosion to 0.039" before exceeding code allowable stresses from the applied forces (LOCA pressure) when treated as a flat plate with fixed supports and no support beneath. This computation method does not demonstrate the code allowable stresses being satisfied as section III applied other loads and applies the pressure load using defined equations different than what is provided here. As documented in Ref 10 the ¼" liner thickness was chosen for ease of fabrication purposes only to allow the fabricator to work with a structure that will not collapse during fabrication

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and concrete pouring against the liner; any thickness of liner is acceptable to perform the function of a leak tight membrane.

Although no minimum line thickness is required, UFSAR Section 5.1.4.3 lists some design cases that were applied to ensure specified leak-rate under LOCA conditions are met.

a) *The liner is protected against damage by missiles*
b) *The liner plate strains are limited to allowable values that have seen shown to result in leak-tight vessels or pressure piping*
c) *The liner plate is prevented from development of significant distortion*
d) *All discontinuities and openings are properly anchored to accommodate the forces exerted by the restrained liner plate, and careful attention is paid to details of corners and connection to minimize the effects of discontinuities.*

In response to item ‘a’ the liner is protected by missiles by way of 15-18” of reinforced concrete. The area in question is the approximately 1” wide joint surrounding the periphery pedestal(s). Per Ref 3, the area of the liner being evaluated is the liner directly under the joint. Even with the degraded moisture barriers, the barrier gap is too small to allow the entry of missiles. Corrosion of the liner does not affect the protection from missiles.

In response to item ‘b’, as stated in UFSAR section 5.1.4.3 the maximum strain in the liner is less than 0.0025in/in. Since strain is linear to stress and stress is inversely linear to cross sectional area, the strain in the possibly corroded areas would be inversely linear to the liner thickness. A strain of 0.0025in/in in a ¼” plate would be 0.016in/in in any areas where the liner is thinned to 0.039inches. The UFSAR states that a strain of 2% (0.02in/in) would meet the requirements of ASME BPVC, although a conservative strain of 0.5% (0.005in/in) was chosen for initial design. If the peak strain values are located in the floor liner section, the peak strain would be higher than the maximum value used during initial design but would be less than the code allowable value. The peak strains are not likely to be located in the areas of concern for possible corrosion as these areas are located next to pedestals which contain anchoring that would restrain and fix that section of the liner, highest strains would be expected and the midpoint between anchors. The strain in the liner would not compromise the integrity of the leak-tight membrane.

In response to item ‘c’, the liner plate is restrained against significant distortion by continuous angle anchors (Per the UFSAR). Additionally, the section of liner in question is restrained by the containment shell and basement floor slab and will not be able to distort significantly. The localized areas of corrosion and liner thinning will not impact the resistance to distortion.

In response to item ‘d’, the areas of concern for possible corrosion are not near any discontinuities or openings. No additional evaluation is necessary.

Additionally, UFSAR table 5-1 summarizes the loads in the containment structure during design accident conditions. The stresses for the interior surfaces of the containment floor are all negative indicating that they are compressive stresses. Under compressive stress the typical failure mode would be buckling; the liner in the floor of containment is between two layers of concrete which would preclude buckling.

Liner Remaining Thickness Analysis (Shear Analysis) for Pitted Area:
If a through hole developed in the liner from pitting, gross liner failure would not occur provided the surrounding base metal is at least 0.039” thick. The ability of the liner to resist LOCA pressure in pitted areas can be best evaluating by treating the area under the pit as a cylinder and determining what amount of force would be required to shear the cylinder away from the adjacent wall area beneath the pit.

A-36 steel has a minimum yield stress of 36,000 psi and shear is conservatively assumed to occur at 40% of yield strength. Actual yield stresses are typically 60% of yield stress for carbon steels.

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The following equation can be developed for the shear strength

[(LOCA pressure) * (Area expose to pressure)]/[cylindrical circumference * wall thickness] = shear strength

[50*pi*r^2]/[2*pi*r*t] = 0.4*36000

This equation becomes r = (2*(shear strength) * t)/50
Where r is the radius of a pit location and t is the local wall thickness in the pitted location.

Substituting various wall thickness results in the following corresponding pit radii. It can be seen that with a remaining wall thickness of 0.01 inches a 5.76" radius pit can be tolerated before the liner would fail from LOCA pressure. By definition, a pit would have a much smaller radius typically less than 1/8" diameter. It can thus be concluded that any expected pitting would not cause a failure of the liner. This is the same methodology used previously in ES200000318.

Thickness (inch)	Radii (inch)
.102	58.8
.05	28.8
.04	23.04
.03	17.28
.02	11.52
.01	5.76
.0002	1/8"

Corrosion Rate:
It is not known when the moisture barrier became degraded. Construction of Calvert Cliffs Unit 1 and 2 was started in July 1969. Unit 1 went into commercial operation in May 1975 and Unit 2 in April 1977. Assume for 10 years the plant had no issue with regard to degradation of the moisture barrier or corrosion of the containment liner and the corrosion started in 1985 and continued until the next refueling outage in 2024 for Unit 1. This is conservative as moisture barrier degradation was first identified in the mid 1990s, IR 02253488 was the first IR that could be found related to moisture barriers or containment liner degradation, this IR is from 1996. When the moisture barrier around the transition between wall and floor liner was replaced as documented in ES200000318 (Ref 4), the liner below the top of the slab was found coated with a coal tar epoxy coating. The cold tar epoxy coating life expectancy is approximately 10-20 years (Ref 15).

- Assuming the corrosion started in 1985 and continues up to the next outage: 2024 - 1985 = 39 years
- It is assumed that the liner, in the location the of the moisture barrier, has been submerged for the duration.
- The maximum acceptable corrosion rate would be: (0.25"- 0.039") / 39 years = 0.0054" = 0.0054*1000 = **5.4 mil / year**

  This means if the corrosion started in 1985 and continued to the next refueling outage at a rate of 5.4 mils/year, we remain above the minimum thickness of 0.039" for the corroded area up to the time of the next refueling outage.

  ES200000318 (Ref 4) has indicated that corrosion rate for Palisades (PWR – similar to Calvert Cliffs) in 2000 for 30 years was 1.3 mil/year. Reference 4 also indicated Point Beach Nuclear (PWR similar to Calvert Cliffs) had a corrosion rate of 2.5 mil/year with 1/8" to 3" of standing water. This calculation shows that the maximum allowable corrosion rate is 5.4 mil/year which is larger than the measured corrosion rates at similar plants. This means if moisture has made its way to the liner and resulted in 39

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years of corrosion would not invalidate the liner water barrier function as it has enough remaining wall thickness available even upon imposing a LOCA pressure load during the next operating cycle.

Per ES200000318 the estimated corrosion rate is between 5 to 10 mils per year for carbon steel in salt water and is between 2 to 7 mils per year for carbon steel in borated water. Given the systems and fluids used in the reactor building it is unlikely that any moisture on the liner would be saltwater but would be borated water. EPRI guidebook MRP-058 (Ref 9) has published corrosion rates for carbon steels in various environments. For carbon steels submerged in ~100F water with 2000-2500 ppm boron corrosion rates are <0.1 mils/year for deaerated water and 2-7 mils/year for aerated water. The water that goes into containment is CCW, SRW, and RCS; all of these water sources are chemically treated and would be closer to deaerated.

Chemistry testing was performed on the water found beneath the degraded moisture barriers; the testing showed a pH of 10 (See attachment 4). Carbon steel will corrode in high alkaline environments however the corrosion rate is much less than in acidic environments when the pH is less than 13. Reference 11 states that steel in a pH range of 12-13 forms a passive film which lowers the rate of corrosion to extremely smally values of less than 1micrometer per year (0.00004in/year) however this is based on clean, contaminant free water and concrete. Attachment 3 shows corrosion for carbon steel in alkaline water with a pH of 7 to 12 to be less than that of acidic water which are on the order of 2mil/year to 7 mil/year. At a pH value of about 12.5 the corrosion rate grows very quickly with increasing pH.

Thus, there is reasonable assurance that the corrosion rate of the liner would be less than 5 mils/year. If corrosion started in 1985, which is a conservative assumption, the thickness of the liner would be expected to remain above 0.039" until the next refueling outage. A liner thickness, in the suspect areas, of 0.039" or greater would not be challenged in performing its function as a leak-tight membrane.

Conclusion/Findings:

This evaluation was performed using conservative inputs, methods, and corrosion rates to compare the projected containment liner wall thickness in 2024 to the minimum required wall thickness to perform the safety related function of the liner, which is to serve as a leak tight membrane. This evaluation assumes that corrosion of the underlying containment liner began in 1985 and projected wall loss through the next outage, 2024. This evaluation concluded that the degraded containment pedestal moisture barriers would not result in degradation sufficient to preclude the containment liner from achieving its safety related function and is therefore acceptable as is. The corrosion rates discussed in Ref 4 and utilized above were assuming material submersion, therefore it is acceptable to leave the remaining standing water in contact with the liner.

As shown above, the degraded moisture barriers would not result in containment liner damage sufficient to preclude the liner from achieving its UFSAR described function of providing a leak tight membrane. Conservative inputs and methodologies were used to show that the liner would have adequate thickness to fulfill its intended leakage barrier function upon experiencing a LOCA pressure load. It has also been shown that the liner has adequate thickness to maintain this design function until the next refueling outage in 2024, when repairs to the moisture barrier and liner, if required, can be performed. During the 2020 refueling outage an Integrated Leak Rate Test (ILRT) was performed on unit 1 containment with satisfactory results, showing that the containment liner is capable of meeting its design function per 10 CFR Appendix J Option B to Part 50. Following the ILRT there was no indication of issues with the liner.

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During, inspection of the liner following the excavation of the joint(s) discussed above, standing water was observed. Although unconfirmed, the source of the water is believed to be a result of water leaks etc from inside containment. Therefore, it is assumed the liner is still performing its leak tight function.

Following inspection of the underlying containment liner, the areas of degraded moisture barrier were repaired using an approved sealant to prevent further moisture intrusion into the inaccessible areas. Attempts were made, to the extent possible, to perform examinations of the liner for evidence of flaws and degradation. Visual examinations were performed with a borescope to identify the current health of the liner but were inconclusive. The area is inaccessible and further examinations could not be performed. Successive inspections of the containment liner beneath the moisture barrier, as required by IWE-2420(b), will be performed during the next refueling outage and beyond until the condition is determined to be relatively unchanged. More extensive repairs to the moisture barrier may be performed during future outages.

Further engineering investigation using site construction photographs dating back to 1969 indicates the presence of test channels surrounding the containment pedestals. The indications in the photographs are confirmed by Ref 15. The test channels are size 3C4.1 arranged along the perimeter of the pedestals and tied into the test channel map that runs throughout the containment liner. Therefore, there is reasonable assurance that the standing water and corrosion observed is on top of/interacting with the 3" wide test channel and not the containment liner itself. Field depth measurements support this configuration; the depth(s) observed by the craft align with the approximate depth of the test channels.

Attachments:

1. Reasonable Plate Thickness Margin and Corrosion Rate Computation
2. Degraded Barrier Locations
3. Boiler Water Treatment Preventative Maintenance ChemREADY pdf
4. Chemistry Analysis Results

References:

1. 61761 Rev 5, "Section at Center Line Reactor Vessel"
2. 61756SH0001 Rev 15, "Containment Interior Plan EL. 10'-0" (Concrete)"
3. 61756SH0002 Rev 1, "Containment Interior Plan @ EL 10' - 0" (Concrete)"
4. ES200000318 Rev 0, "Engineering Evaluation of Degraded Areas of Unit 1 Containment Steel Liner"
5. ASME Section XI 2013, "Rules for Inservice Inspection of Nuclear Power Plant Components"
6. UFSAR Rev 52, "Update Final Safety Analysis Report"
7. Roark's Formulas for Stress & Strain 6th Edition
8. ASME BPVC Section II Part D, 2013 edition
9. EPRI Technical Report MRP-058 Rev 2, "Materials Reliability Program: Boric Acid Corrosion Guidebook Managing Boric Acid Corrosion Issues at PWR Power Stations"
10. ES199502082 rev 0, "Containment Liner Thickness"
11. SAND2010-8718, "Sandia Report: Nuclear Containment Steel Liner Corrosion Workshop"
12. 61727 Rev 2, "Containment Structure Foundation Bottom Base Slab – Bottom Reinforcement"
13. C-0016 Rev 8, "Furnishing, Fabricating, Delivery and Erection of the Containment Structure Liner Plate and Accessory Steel"
14. 2020-08 "Calvert Cliffs Unit 1 2020 ILRT Report"
15. "Coal Tar Enamel & Coal Tar Epoxy Materials Analysis and Performance History" – Bobbi Jo Merten 9/20/2017
16. NRC Information Notice No. 97-10 "Liner Plate Corrosion in Concrete Containments"
17. EPRI Technical Brief 3002021004 "Deterioration and Evaluation of Steel Liners and Vessels: Operating Experience"
18. 61744 Rev 15 "Containment Liner Floor Plan & Details"
19. IR 02253488 Provide Minimum Acceptable Containment Liner Thickness

Evaluate liner treating it as a rectangular flat plate, without taking credit for the concrete floor it is resting on in the area of load. The plate is supported on all 4 sides.

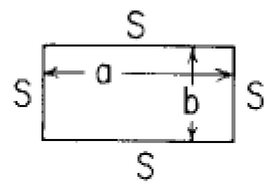
$\sigma_{yield} := 36000 \cdot psi$

$\sigma_{allowable} := 16600 \cdot psi$

$LOCApressure := 50 \cdot psi$

$a := 24 \cdot in$
$b := 1 \cdot in$

Simply supported flat plate

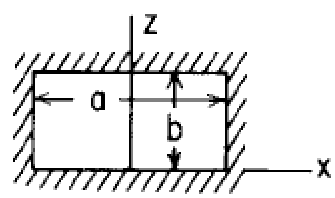


$\frac{a}{b} = 24$ $\beta := .75$

$q := LOCApressure = 50\ psi$

$t_{minSimple} := \sqrt{\frac{\beta \cdot q \cdot b^2}{\sigma_{allowable}}} = 0.0475\ in$

Flat plate with fixed edges



$\frac{a}{b} = 24$ $\beta_1 := .5$

$t_{minFixed} := \sqrt{\frac{\beta_1 \cdot q \cdot b^2}{\sigma_{allowable}}} = 0.0388\ in$

If we use yield stress instead of allowable stress, for plate with fixed edges

$t := \sqrt{\frac{\beta_1 \cdot q \cdot b^2}{\sigma_{yield}}} = 0.0264\ in$

Evaluation of possible pitting

$\tau := 0.4 \cdot \sigma_{yield} = 14400\ psi$

$$t_{shear} := \begin{bmatrix} .102 \cdot in \\ .05 \cdot in \\ .04 \cdot in \\ .03 \cdot in \\ .02 \cdot in \\ .01 \cdot in \\ .0002 \cdot in \end{bmatrix} \qquad r_{shear} := \frac{2 \cdot \tau \cdot t_{shear}}{q} = \begin{bmatrix} 58.752 \\ 28.8 \\ 23.04 \\ 17.28 \\ 11.52 \\ 5.76 \\ 0.1152 \end{bmatrix} in$$

Determine maximum allowable corrosion rate. This is the corrosion rate which would result in tmin over the selected corrosion period.

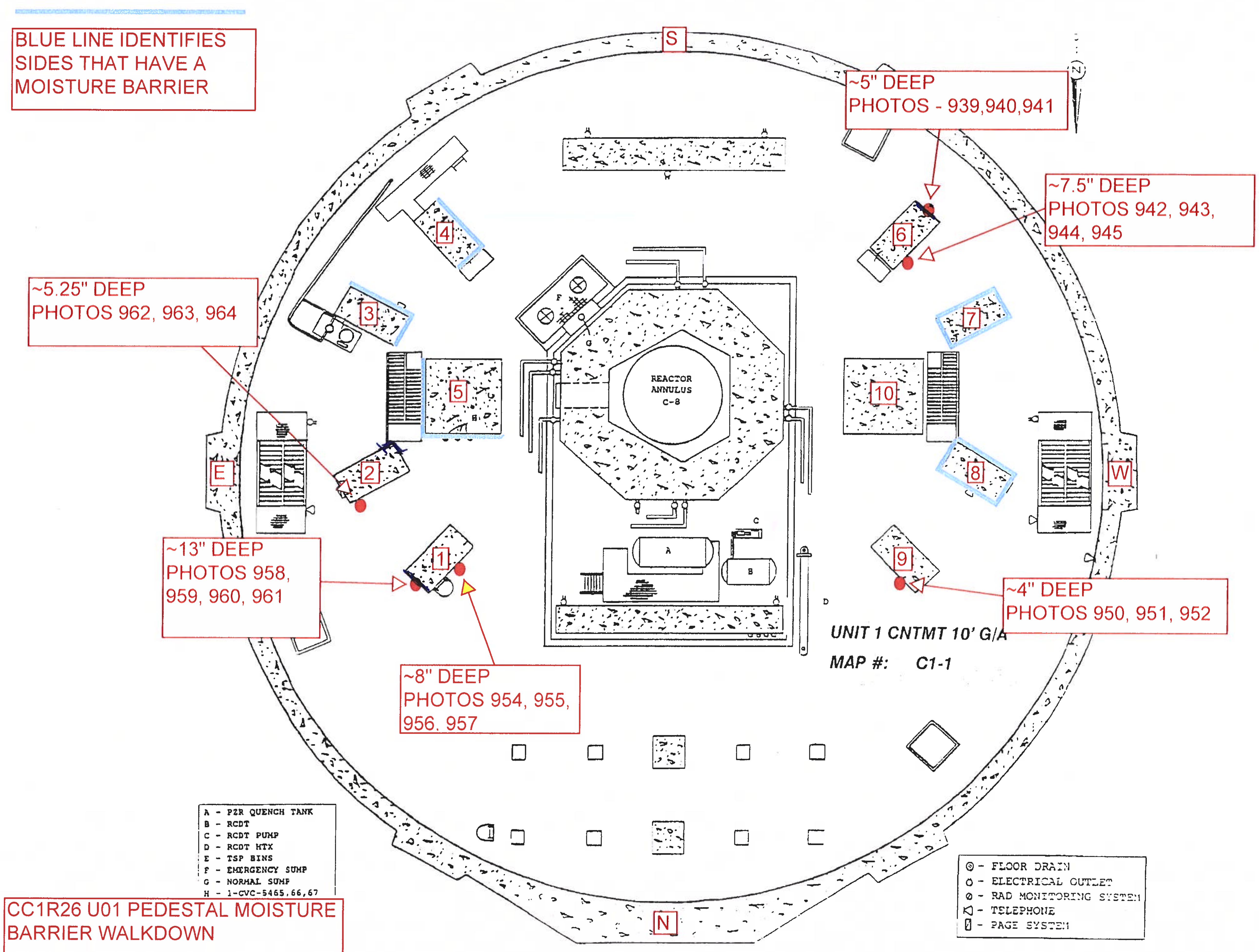
$yearsOfCorrosion := 2024 - 1985 = 39$

$t_{initial} := 0.250 \cdot in$

$allowedCorrosion := t_{initial} - t_{minFixed} = 0.2112\ in$

$$allowableCorrosionRate := \frac{allowedCorrosion}{yearsOfCorrosion} = 0.0054\ in$$

$milsperyear := allowableCorrosionRate \cdot 1000 = 5.4152\ in$


BLUE LINE IDENTIFIES SIDES THAT HAVE A MOISTURE BARRIER
S
~5" DEEP
PHOTOS - 939,940,941
N
~7.5" DEEP
PHOTOS 942, 943, 944, 945
~5.25" DEEP
PHOTOS 962, 963, 964
REACTOR ANNULUS C-8
E
W
1
2
3
4
5
6
7
8
9
10
~13" DEEP
PHOTOS 958, 959, 960, 961
~4" DEEP
PHOTOS 950, 951, 952
UNIT 1 CNTMT 10' G/A
MAP #: C1-1
~8" DEEP
PHOTOS 954, 955, 956, 957
A - PZR QUENCH TANK
B - RCDT
C - RCDT PUMP
D - RCDT HTX
E - TSP BINS
F - EMERGENCY SUMP
G - NORMAL SUMP
H - 1-CVC-5465,66,67
FLOOR DRAIN
ELECTRICAL OUTLET
RAD MONITORING SYSTEM
TELEPHONE
PAGE SYSTEM
N
CC1R26 U01 PEDESTAL MOISTURE BARRIER WALKDOWN

Boiler Treatment Water Treatment

Boiler Water Treatment Preventative Maintenance BMP’s

Why is Boiler Water Treatment Required?

No matter the type of boiler you work with, corrosion is always a risk and not everyone understanc
water treatment program, required to prevent equipment damage.

Corrosion is commonly caused by oxygen or improper pH control. This can create holes in economi
resulting in boiler leaks and a pricey fix (see the next section for more). There are many forms of co

It is necessary to consider the quantity of the various harmful substances that can be allowed in the
to the boiler. Corrosion may occur in the feed-water system as a result of low pH water and the pre
dioxide.

Corrosion can be minimized through proper design (to minimize erosion), periodic cleaning, and co
pH, and dissolved solids. So when you ask yourself, why is boiler water treatment required, the bes
level is through continuous control and utilizing an automated chemical feed and monitoring systei
feedwater (and promote passivation of metal surfaces). Deaerators are also used to heat feedwate
gases to acceptable levels in some facilities as an additional means of preventative treatment to the
help to reduce the amount of chemical consumed.

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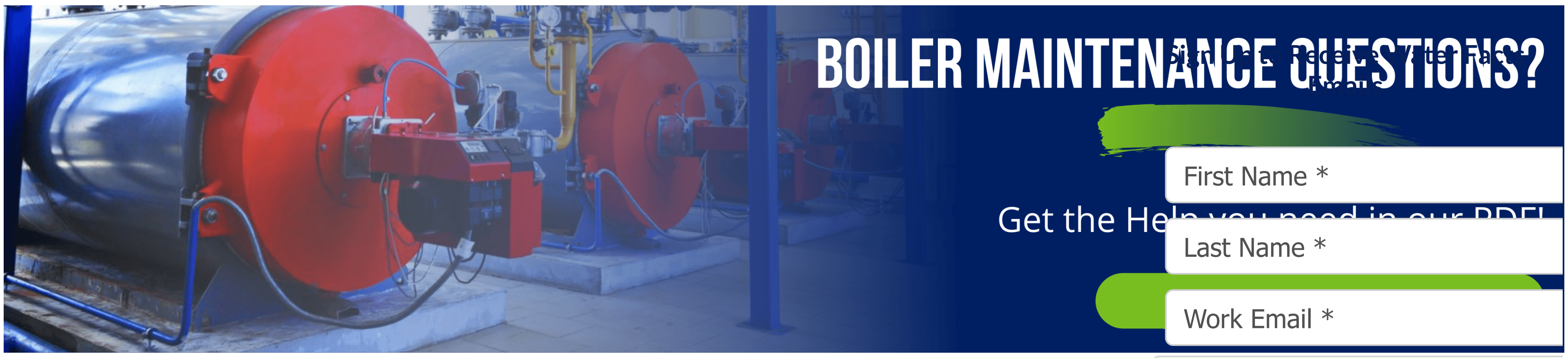
The Facts on the New 2022 Water Treatment Standard for Healthcare Facilities

Six Things You Should Know About Legionella



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Major monitoring parameters required for water treatment:

1. Dissolved solids
2. pH of the boiler feed water
3. Dissolved Oxygen in the feed water entering the boiler
4. Silica in boiler water

Learn more about our Water Treatment Services and Chemical Products

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Automated feed systems provide the following benefits to any preventative maintenance water treatment program:

- Little to no handling of chemicals for employees (less chance of chemical spills)

- No overdosing of chemicals (potentially costing more money)
- No under-dosing of chemicals (allowing potential corrosion to occur)
- Ability to monitor and track system consistency (both operations and cost related)

How Much Does it Cost to Maintain a Boiler System

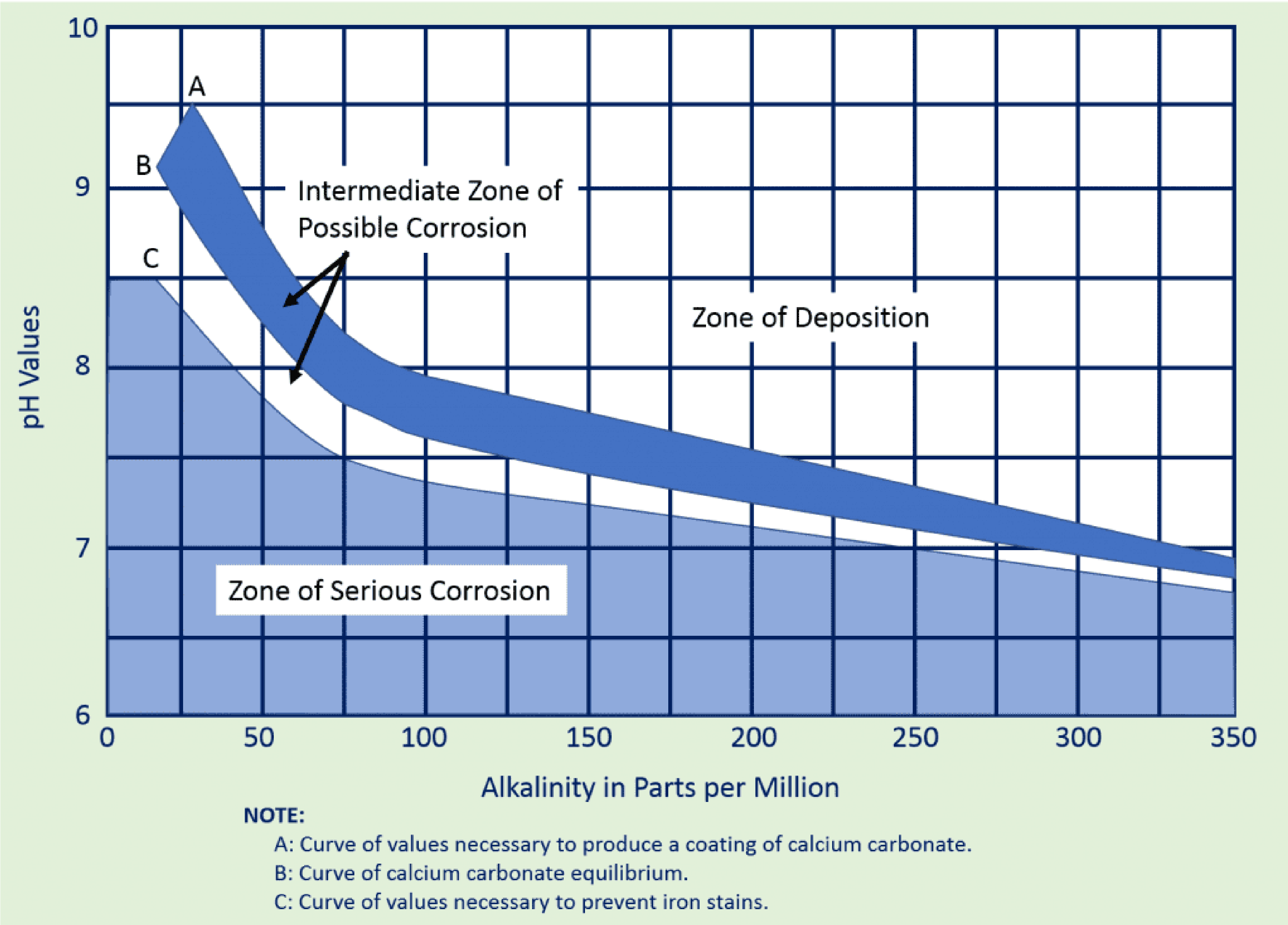
Because of a boiler's vital function for any facility, their breakdown can result in safety concerns, not to mention a huge cost in order to replace or repair the system. Repair costs to boilers can be steep and can range anywhere from a few thousand dollars to over $1 million depending on size, function and accessibility. But it doesn't stop there. This price is in addition to the expense of operational down times to get the boilers repaired or replaced and up and running properly.

The cost of automating a boiler water feed system can range anywhere from a few thousand dollars up to $50K, depending on the size, demand and number of boilers any one facility may have in place.

What Are The Disadvantages Of Boiler Corrosion?

Minutes' worth of imbalance in a water treatment program can cause problems, therefore, the fewer fluctuations in a water treatment program and water quality feeding the boiler the better it is for the equipment. When a system is not continuously treated and tested for accuracy, chemical imbalances can occur, allowing minutes, hours or days' worth of potential corrosion and scaling to occur.

The graph below is known as the Baylis Curve. It shows the relationship between pH, alkalinity, and water stability. Water above the lines is scale-forming while water below the lines is corrosive. Stable water is found in the white area between the lines.



As you can see by the above graph, there is a fairly "fine line" between corrosive and not corrosive when it comes to a heated boiler water system. The pH, alkalinity, temperature of the water and various other factors will play a role in dictating whether or not there is a possibility that the water has gone corrosive and has begun to eat away at your infrastructure.

In these scenarios, we like to refer to these systems as "not if's but when's", because we know it is only a matter of WHEN the corrosion will be enough to cause a problem and not a matter of IF it will.

Keep in mind that corrosion is the only SYMPTOM and the CAUSE is inconsistent feed water.

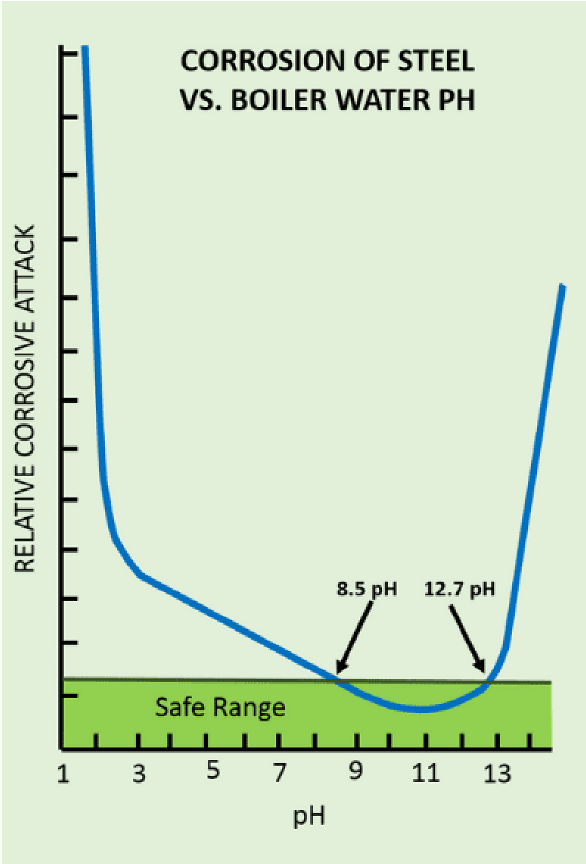
Why Is Water Quality Important?

Water contains dissolved salts, which upon evaporation of water forms scales on the heat transfer surfaces. Scales have much lower heat transfer capacity than steel: the heat transfer coefficient of the scales is 1 kcal/m/°C/hr against 15 kcal/m/°C/hr for steel. This leads to overheating and failure of the boiler tubes. Scale also reduces flow area, which increases pressure drop in boiler tubes and piping.

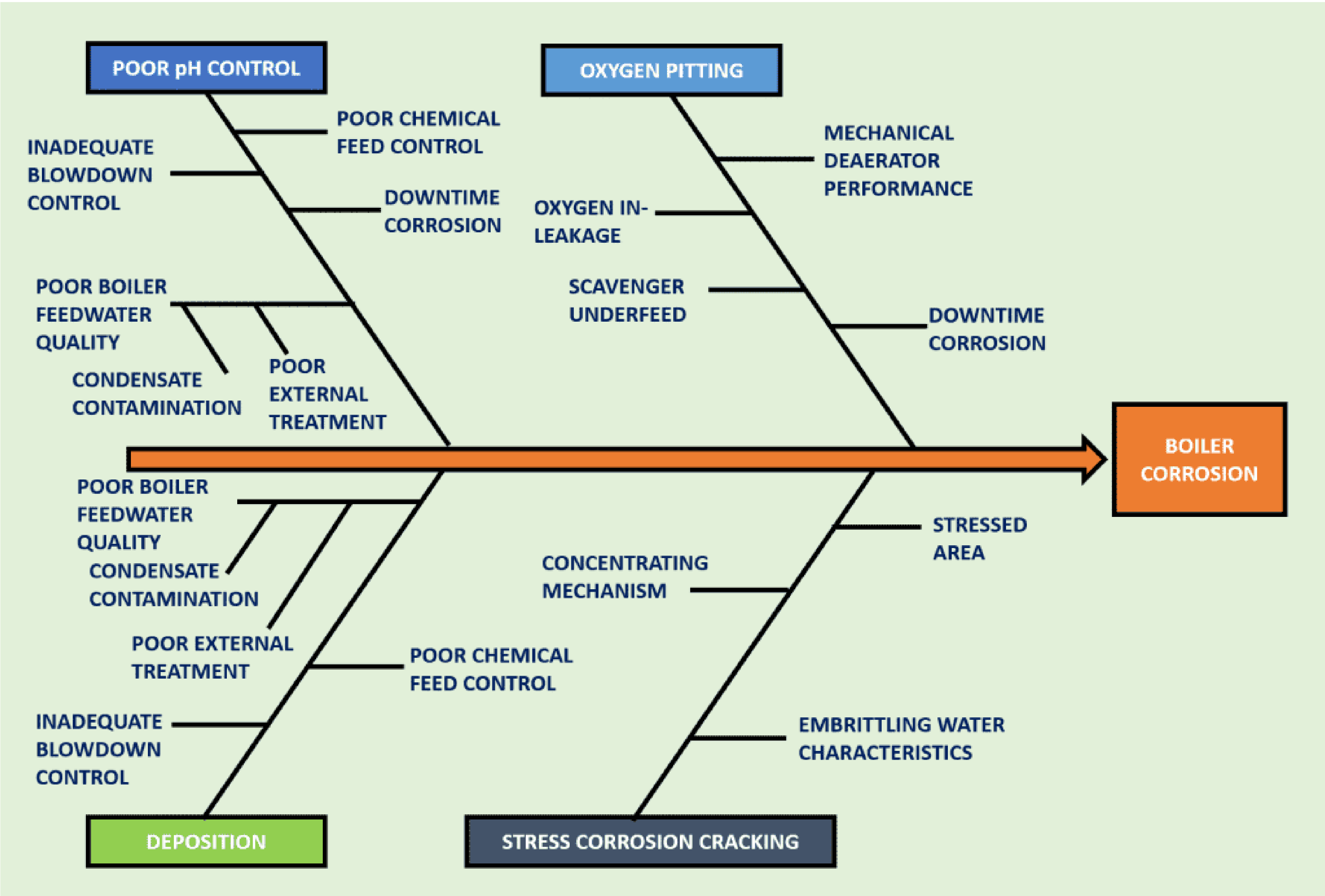
Low pH or dissolved oxygen in the water attacks the steel. This causes pitting or lowering the thickness of the steel tubes, leading to rupture of the boiler tubes. Contaminants like chlorides, a problem in seawater cooled power plants, also behave in a similar way.

Flow assisted corrosion occurs in the carbon steel pipes due to the continuous removal of the protective oxide layer at high flows.

Impurities carried over in the steam, causing deposits on turbine blades leading to reduced turbine efficiency, high vibrations, and blade failure. These contaminants can also cause erosion of turbine blades. Silica at higher operating pressures volatilizes and carries over to the turbine blades.



What Maintenance Does A Boiler Need?



1. The first step is to get the make-up water to the steam cycle as pure as possible.

2. The second step is to form a protective layer on the inside surface of the tubes which protects the metal surface from any further corrosion attacks.

3. The third step is to maintain this layer throughout the life of the plant. If the water quality goes down, this protective layer will be destroyed and corrosion starts damaging the tubes.

How Do You Maintain A Boiler System?

Even the most aggressive forms of prevention can't stop minor corrosion from eventually happening. But, with the right approach, the effects of corrosion can be minimized and extend the life of your boiler. While ChemREADY cannot reverse time and corrosion – we can certainly stop corrosion in its tracks!

Here's what to do to minimize the effect of corrosion before it happens:

Use a boiler logbook. Regularly tracking the normal operation of your boiler room equipment makes it easy to spot when something critical changes.\

- Deaerator pressure or feed-tank temperature changes will give advance warning of a more expensive corrosion problem. pH changes could indicate problems with water treatment or process contamination.

Treat Feedwater. Additives can ensure that any oxygen that makes its way to the boiler in the feedwater is rapidly absorbed before it has the opportunity to form corrosive cells and blisters.

- Work with a good water chemistry company (like ChemREADY!) to stay on top of your boiler water.

Implement a strict, regular service program to ensure the boiler stays clean and free of scale and corrosion problems. Train employees to ensure a complete understanding of the boiler system, how it operates and its importance

- If the boiler is being inspected, the root cause can be addressed early, avoiding more costly repairs.

For hydronic systems, check for leaks and monitor the quantity of make-up water. Hot water heating systems shouldn't need make-up water unless something is wrong. Call your service provider to fix the leak right away, or you may be replacing the boiler next year.

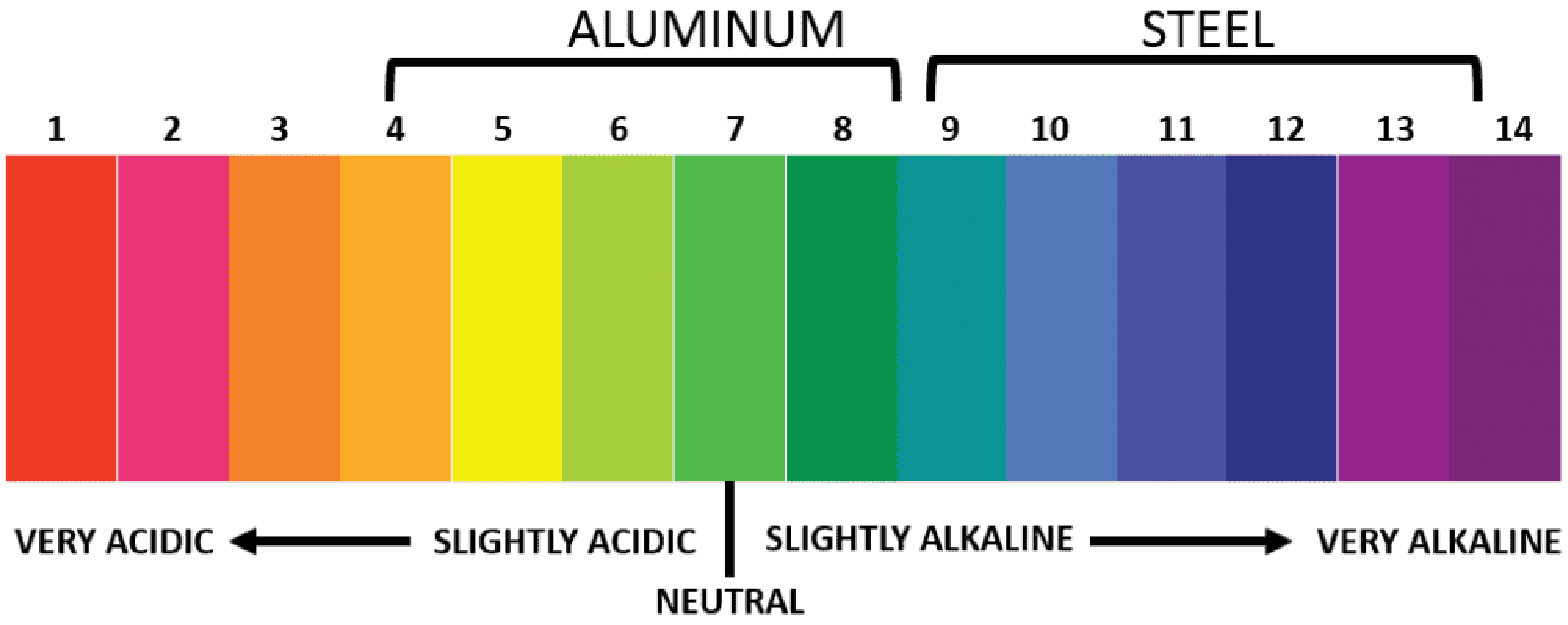
Automate boiler chemical feed and surface blowdown to maintain uniform chemical residuals and conductivity levels.

How To Treat Corrosion Damage?

- Make necessary repairs to boiler and piping (such as having boiler re-tubed)
- Train your crew on boiler preventative maintenance and water chemistry tests
- Document and report any signs of corrosion to your boiler service provider and your water chemical company so they can help prevent further damage.

Use our tips to ensure the longevity of your boiler. Need some expert advice or repair services? Contact ChemREADY today to schedule your free consultation.

Did You Know?



What Are Different Types Of Corrosion?

Caustic Corrosion. When a concentrated caustic substance dissolves the protective magnetite layer of a boiler. This is commonly caused by boiler water pH being too high, steam blanketing (poor circulation) or local 'film boiling'. If your boiler has a porous scale, then under deposit corrosion is also possible. Boiler water pH should be a part of your logbook.

Acidic Corrosion. Results from the mishandling of chemicals during acid cleaning operations or the boiler pH being run too low to passivate the carbon steel surfaces of the boiler. Boiler water pH should be a part of your logbook.

Pitting Corrosion. This is one of the most destructive types of corrosion, as it can be hard to predict before a leak forms. Pitting is a localized form of corrosion, in which either a local anodic point or more commonly a cathodic point, forms a small corrosion cell within the surrounding normal surface. Oxygen in feedwater is a common cause of boiler tube pitting. If your boiler is pitting, investigate the proper operation of your deaerator or feedwater tank and chemical treatment. If you have a hot water system, oxygen pitting can occur if the system has a leak and is bringing in fresh water.

Crevice Corrosion. This type of corrosion is also a localized form of corrosion and usually results from a crack in the boiler that does not get good circulation to rinse away caustic.

Galvanic Corrosion. Galvanic corrosion is the degradation of one metal near a joint or juncture that occurs when two electrochemically dissimilar metals are in electrical contact in an electrolytic environment. So, dissimilar metals may need a special dielectric joint, sacrificial anode, or active cathodic protection system to prevent this phenomenon.

Learn More about ChemREADY's Boiler Water Treatment Services

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CC1R26 Unit 1 Pedestal 6A and 2A Sampling and Analysis

Ernest Thomas, Senior Chemist

Executive Summary

Samples obtained on 2/23/2022 from PED 6A and PED 2A in U-2 containment was analyzed via gamma spectroscopy. No short-lived isotopes were detected. No age estimates were generated through comparison of isotopic ratios detected due the inclusion of solid material in the samples. Cs-137, Co-58 and Co-60 ratios were detected in the samples but was unable to be quantified due to sample composition and size. Samples consisted of liquid, likely water and solid material resembling concrete. A pH analysis was performed with all samples having a pH of 10 S.U. which is consistent with water that has been that has been in contact with concrete for an extended time. A dissolved oxygen analysis was attempted but the sample contained too much sediment to be performed.