THE NATIONAL BOARD
OF BOILER AND PRESSURE VESSEL INSPECTORS

Date Distributed:

NATIONAL BOARD INSPECTION CODE
SUBCOMMITTEE INSPECTION

AGENDA

Meeting of July 9, 2025

Cincinnati, OH

The National Board of Boiler & Pressure Vessel Inspectors
1055 Crupper Avenue
Columbus, Ohio 43229-1183
Phone: (614)888-8320

1. **Call to Order**
The meeting will be called to order at 8:00 a.m. Eastern Time, in Madisonville A on the 4th floor of the hotel.

2. **Introduction of Members and Visitors**

3. **Check for a Quorum**

4. **Awards/Special Recognition**

5. **Announcements**
   - This meeting marks the end of Cycle B for the 2027 NBIC edition.
   - The National Board will be hosting a reception on Wednesday evening from 5:30 p.m. to 7:30 p.m. at Ault Park, on the 4th floor of the hotel.
   - The National Board will be hosting breakfast and lunch on Thursday for those attending the Main Committee meeting. Breakfast will be served from 7:00 a.m. to 8:00 a.m. in Madisonville A/B, and lunch will be served from 11:30 a.m. to 12:30 p.m. in Madisonville A/B.
   - Meeting schedules, meeting room layouts, and other helpful information can be found on the National Board website under the **NBIC** tab → NBIC Meeting Information.
   - The NBIC Committee has transitioned from NB File Share to SharePoint. Remember to add any attachments that you'd like to show during the meeting (proposals, reference documents, powerpoints, etc.) to the NBIC SharePoint site (nationalboard.sharepoint.com/sites/NBIC) **prior to the meeting**.
     - Note that access to the NBIC SharePoint site is limited to committee members only.
     - ALL powerpoint attachments/presentations must be sent to the NBIC Secretary for approval prior to the meeting.
     - Contact Jonathan Ellis (*nbicsecretary@nbbi.org*) for any questions regarding NBIC SharePoint access.
   - When possible, please submit proposals in Word format showing "strike through/underline." Project Managers: please ensure any proposals containing text from previous NBIC editions are updated with text from the most current edition.
   - If you'd like to request a new Interpretation or Action item, do so on the National Board Business Center.
     - Anyone, member or not, can request a new item.
   - As a reminder, anyone who would like to become a member of a group or committee:
     - Should attend at least two meetings prior to being put on the agenda for membership consideration. The nominee will be on the agenda for voting during their third meeting.
     - The nominee must submit the formal request along with their resume to the NBIC Secretary **PRIOR TO** the meeting. *nbicsecretary@nbbi.org*
     - If needed, we can also create a ballot for voting on a new member between meetings.
   - Thank you to everyone who registered online for this meeting. The online registration is very helpful for planning our reception, meals, room setup, etc. It is also a good way to make sure we have the most up-to-date contact information. Please continue to use the online registration for each meeting.

6. **Adoption of the Agenda**

7. **Approval of the Minutes of the January 2025 Meeting**
The minutes from the January 2025 meeting can be found on the NBIC Committee information page on the National Board's website, nbbi.org.

8. **Review of Rosters**
   a. **Membership Nominations**
      - **SUBGROUP**: Mr. Wil Griffith (AIA) and Mr. James Bell (Manufacturers) are interested in becoming members of Subgroup Inspection.

   b. **Membership Reappointments**
      - **SUBGROUP**: The following members are up for reappointment: Mr. Pat Polick and Mr. David Rose.

      - **SUBCOMMITTEE**: The following members are up for reappointment: Mr. James Clark, Mr. Pat Polick, and Mr. David Rose.

   c. **Officer Appointments - None**

9. **Open Items Related to Inspection**

   a. **Part 2/3 Task Group Items**
      i. **22-06 - General Description:** Part 2 task group to review Part 3 Item 21-53 (see below)
      ii. **23-08 - General Description:** Part 2 task group to review Part 3 Item 21-67 (note: item 21-67 had a proposal that passed through SG/SC R&A and MC in January 2024.)
      iii. **24-28 - General Description:** Applying PWHT to previously "as welded" item

   b. **PRD**
      i. **Item 24-91** – Require means to prevent safety valve discharge piping blockage for LCDSV (Part 4).

   c. **R&A**
      i. **Item 21-53** – Post repair inspection of weld repairs to CSEF steels. (P. Gilston as PM)

      ii. **Item 24-18** – Definition of Controlled Fill (P. Gilston as PM)

10. **Interpretations**

Item Number: 25-02	**NBIC Location:** 2023 NBIC, Part 2, 4.4.7.3 and 4.5.3 b)	**Attachment Page 1**
General Description: Overriding Part 2 Inspection Requirements with RBI Program **Subgroup:** Inspection **Task Group:** D. Graf (PM), J. Beauregard, J. Sowinski, J. Mangas, L. Burton, B. Ray **Submitted by:** Riley Collins **Explanation of Need:** There needs to be some clarity on whether an RBI program has the ability to override some of the inspection requirements listed in Part 2 as long as all jurisdictional requirements are met.		
January 2025 Meeting Action: After Review of the interpretation, the SG chose to create a TG.		

Item Number: 25-34	NBIC Location: 2023 NBIC, Part 2, 2.3.6.2 b) 2) a. 3.	Attachment Page 2
General Description: Interpretation request into the NBBI for the NB-23 2023 paragraph 2.3.6.2 **Subgroup:** Inspection **Task Group:** None assigned. **Submitted by:** Ari Ben Swartz **Explanation of Need:** Numerous air receivers are found to be less than the required wall thickness.		
July 2025 Meeting Action:		

11. Action Items

a. TG FRP Items

Item Number: NB16-1402	NBIC Location: Part 2, New Supplement	Attachment Page 3
General Description: Life extension for high pressure FRP vessels above 20 years **Subgroup:** FRP **Task Group:** M. Gorman (PM)		
Update from the October 2024 TG FRP Meeting: The task group is finalizing the proposal for this item and should have something ready to present at the July 2025 meeting.		
January 2025 Meeting Action: Progress Report. The Inspection SC took no action on this item. Update: TG FRP approved a proposal for this item at their April 2025 meeting.		

b. TG Historical Items

Item Number: 23-85	NBIC Location: Part 2, S2.14.7	No Attachment
General Description: Review paragraphs to replace with proper verbiage **Subgroup:** SG Historical **Task Group:** M. Wahl (PM), K. Anderson **Explanation of Need:** There is some slang and second person (POV) verbiage throughout these paragraphs. Recommend rewording with proper terminology (such that it could be understood internationally) and changing point of view (e.g., changing "you're pulling water" to "water is being pulled"). Since I don't have the technical knowledge to know what is slang and what isn't, what I have proposed will still need to be reworded.		
January 2025 Meeting Action: Progress Report was given at the Historical TG meeting.		

Item Number: 25-14	NBIC Location: Part 2, S2.10.	No Attachment

General Description: UT Inspection of Boilers with Jackets

Subgroup: SG Historical
Task Group: M. Wahl (PM)

Explanation of Need: Currently this information is not in the same location as the other UT requirements and needs to be updated for proper terminology.

July 2025 Meeting Action:

c. TG Locomotive Items

Item Number: 24-78	NBIC Location: Part 2, S1.2.4.22	No Attachment

General Description: Minimum Washout Plug Thread Engagement

Subgroup: Locomotive
Task Group: B. Zeigler (PM), E. Armpriester, D. Domitrovich

Explanation of Need: Text should be changed to clarify how minimum thread engagement is quantified.

January 2025 Meeting Action:
Progress Report. This is a new item and the Locomotive TG created as task group.

Item Number: 25-05	NBIC Location: Part 2, S1.2.4.22	No Attachment

General Description: Washout plug engagement limits for locomotive boilers.

Subgroup: Locomotive
Task Group: L. Moedinger (PM)

Explanation of Need: There is no current wording for washout plug engagement.

July 2025 Meeting Action:

Item Number: 25-16	NBIC Location: Part 2, S1.2.4.22	No Attachment

General Description: Washout plug obstructions

Subgroup: Locomotive
Task Group: T. Sposato (PM)

Explanation of Need: Analyze possible issues.

July 2025 Meeting Action:

d. SG Inspection Items

Item Number: 23-81	**NBIC Location: Part 2, 4.4.3 b)**	**No Attachment**
General Description: Evaluate Inspector responsibilities relating to 4.4.3 FFS **Subgroup:** Inspection **Task Group:** M. Horbaczewski (PM), V. Scarcella, J. Clark, B. Ray, J. Ferreira, J. Sowinski **Submitted by:** R. Underwood **Explanation of Need:** Currently, 4.4.3-b states the Inspector shall review the condition assessment methodology and ensure the inspection data and documentation are in accordance with Section 4. This proposal would redefine the role and responsibility of the Inspector.		
January 2025 Meeting Action: Mr. Horbaczewski gave a progress report.		

Item Number: 24-03	**NBIC Location: Part 2, Supplement 6**	**No Attachment**
General Description: Revise "Inspector" terminology and requirements in Supplement 6 **Subgroup:** Inspection **Task Group:** B. Wilson (PM), R. Kennedy, and J. Smith **Submitted by:** R. Underwood **Explanation of Need:** Part 2 Supplement 6 should be revised to align with Part 3, Suppl 6 and the DOT. A few references are S6.4.2 a), S6.4.2 c), S6.4.4, S6.4.5, S6.4.6, and S6.4.6.1. However, this may not be an all-inclusive list.		
January 2025 Meeting Action: Progress Report. New PM was assigned during the SG meeting.		

Item Number: 24-28	**NBIC Location: Part 2, S9.9 b) 4)**	**No Attachment**
General Description: Applying PWHT to previously "as welded" item **Subgroup:** Inspection **Task Group:** Brent Ray, Paul Davis, Phil Gilston **Submitted by:** J. Swezy **Explanation of Need:** The NBIC clearly lists the application of PWHT to a PRI that was not previously PWHT by the original Manufacturer as an example of an alteration. I agree with that statement and believe it is appropriate to consider this to be an alteration. I do not under why the NBIC considers this as an acceptable alteration but does not provide its users with any guidance as to how they should address its implementation. It seems very clear to me that applying PWHT to such welds is rarely detrimental when properly applied and should not reduce their strength or toughness. If anything, it should prove helpful rather than harmful under properly considered application. Good engineering practice mandates that a carbon steel vessel undergoing a change to wet H2S service should receive PWHT to provide an improved resistance to hydrogen cracking corrosion. Failing to do so would be irresponsible. The NBIC rules for a change of service even mention this as a factor to consider in Part 2, Table S-9.4.		
January 2025 Meeting Action: A task group was formed to work on this item. **Note: on 1.14.25 at SG RA, George Galanes has pulled this item out of STG PT 2 / PT 3. George will interface with Part 2 once the wording has been finalized. This item to be removed prior to next meeting.**		

Item Number: 24-37	NBIC Location: Part 2, 2.2.10	No Attachment
General Description: Add language in the event boiler can't be secured at the time of inspection **Subgroup:** Inspection **Task Group:** T. Bolden (PM), J. Smith, J. Peterson, W. Hackworth, T. Barker, B. Ross **Submitted by:** V. Scarcella **Explanation of Need:** In some circumstances boilers cannot be shut down and a dead man switch is not allowed.		
January 2025 Meeting Action: Mr. Bolden gave a progress report. The proposal will be sent to SG LB for review and comment.		

Item Number: 24-42	NBIC Location: Part 2, 2.4.1 and 2.4.4	No Attachment
General Description: Add language to NBIC Part 2 in regards to piping inspections **Subgroup:** Inspection **Task Group:** D. Graf (PM), K. Barkdoll, R. Kennedy, B. Wilson, J. Beauregard, W. Griffith, G. Kopp **Submitted by:** V. Scarcella **Explanation of Need:** Two fatal incidents resultant from radiator failure prompted an ask for these changes.		
January 2025 Meeting Action: Mr. Graf gave a progress report.		

Item Number: 24-62	NBIC Location: Part 2, Section 2	No Attachment
General Description: Temporary Boiler Inspection **Subgroup:** Inspection **Task Group:** P. Pollick (PM), V. Newton, B. Ross, M. Horbaczewski, J. Mangus, J. Beaureguard, M. Whitlock **Submitted by:** V. Scarcella **Explanation of Need:** No guidance for inspectors for temporary boiler inspections.		
January 2025 Meeting Action: Mr. Horbaczewski gave a progress report for this item.		

Item Number: 24-75	NBIC Location: Part 2, Table 2.5.8	No Attachment
General Description: NBIC Part II Review table 2.5.8, suggest changes to align with NBIC Part 4 **Subgroup:** Inspection **Task Group:** J. Smith (PM), B. Steinhart, T. Bolden, L. Burton **Submitted by:** V. Scarcella **Explanation of Need:** Tim Baker and Tim Bolden raised needed changes to NBIC Part II in table 2.5.8, the table needs review and alignment with the table in Part 4 3.2.6		
January 2025 Meeting Action: Progress Report. TG was created at the SG meeting.		

Item Number: 24-76	NBIC Location: Part 2, S7.9	No Attachment

General Description: Revision to Part 2, S7.9

Subgroup: Inspection
Task Group: T. Vandini (PM), D. Graf, J. Clark, C. Moultrie, L. Burton, M. Whitlock, P. Polick, J. Roberts

Submitted by: James Roberts

Explanation of Need: Currently commercially refurbishers can inspect pressure vessels per NBIC S7.8.1 through S7.8.5 and place back into service without any statement this inspection was completed and by who.

January 2025 Meeting Action:
Progress Report. TG was created at the SG meeting.

Item Number: 24-84	NBIC Location: Part 2, 2.3.6.10 and 2.3.6.11	No Attachment

General Description: Vessels above 10,000 psi reevaluation of remaining life

Subgroup: Inspection
Task Group: V. Newton (PM), J. Mangas, V. Scarcella, D. Fulford, J. King

Submitted by: Craig Bierl

Explanation of Need: Inspectors need to be able to have a paper trail of the code integrity of these vessels. Changing the original data (in this case, designed cycle life) should ONLY be completed with the involvement of an authorized inspector and MUST be documented on a National Board form in order to be audited by the inservice inspector.

January 2025 Meeting Action:
Progress Report. TG was created at the SG meeting.

Item Number: 24-90	NBIC Location: Part 2, S12.7 d)	No Attachment

General Description: Require means to prevent safety valve discharge piping blockage for LCDSV (Part 2)

Subgroup: Inspection
Task Group: None assigned.
Submitted by: Mark Edwards

Explanation of Need: Adding verbiage to the NBIC Part 1, Part 2 and Part 4 to require a means to prevent foreign material introduction to the safety valve discharge pipe.

January 2025 Meeting Action:
Progress Report. No action was taken as the SG wanted to wait until a proposal has been reviewed by PRD.

Item Number: 24-100	**NBIC Location: Part 2, Section 5**	**No Attachment**
General Description: Add field to NB 6 & NB 7 from JRS Team **Subgroup:** Inspection **Task Group:** None assigned. **Submitted by:** V. Scarcella **Explanation of Need:** Repeatedly came up in investigations and in discussions that after reviewing an inspection form the reader has no idea if the object was operating.		
January 2025 Meeting Action: The proposal that was passed unanimously through SG was presented to the SC. A motion was made to accept the proposal as presented. The motion was seconded and **unanimously approved**. NOTE: During the January 2025 meeting, the Main Committee asked the task group to put this on hold while the National Board reviewed the disclaimer language.		

Item Number: 24-104	**NBIC Location: Part 2, 2.1**	**No Attachment**
General Description: Add language clarifying the limitation of inspections presented by design. **Subgroup:** Inspection **Task Group** V. Scarcella (PM), T. Bolden, J. Sowinski, R. Kennedy, W. Griffith, B. Ross, B. Ray, M. Whitlock **Submitted by:** V. Scarcella **Explanation of Need:** Currently an inspector could be held responsible for conditions they could not reasonably access.		
January 2025 Meeting Action: Progress Report. TG was created at the SG meeting.		

Item Number: 24-105	**NBIC Location: Part 2, 1.5.1**	**Attachment Page 19**
General Description: Need to restrict signatures to inspections for which the inspector was present **Subgroup:** Inspection **Task Group:** None assigned. **Submitted by:** V. Scarcella **Explanation of Need:** It has become practice in one jurisdiction for inspectors to sign inspection reports for apprentices.		
January 2025 Meeting Action: The proposal that was passed with one negative through SG was presented to the SC. After review of this proposal in the SC meeting, they chose to send the proposal out to the **SC for review and comment LB**.		

12. New Items

Item Number: 25-23	**NBIC Location: Part 2, 3.4.8**	**Attachment Page 20**
General Description: Add guidance for tube sag allowance **Subgroup:** Inspection **Task Group:** None assigned. **Submitted by:** V. Scarcella **Explanation of Need:** Inspectors were asking for clarification and better guidance. Item needs a working group to consider language.		
July 2025 Meeting Action:		

Item Number: 25-27	**NBIC Location: Part 2, 2.3.6.2, 2.3.6.4, 4.4, S7.8**	**Attachment Page 21**
General Description: Fitness-for-service coordination with API 579-1/ASME FFS-1 **Subgroup:** Inspection **Task Group:** None assigned. **Submitted by:** J. Hadley **Explanation of Need:** Alert users about situations where acceptance criteria in Part 2 may be less strict than API 579-1/ASME FFS-1.		
July 2025 Meeting Action:		

Item Number: 25-31	**NBIC Location: Part 2, New Supplement**	**No Attachment**
General Description: Add a supplement that lists the standard boiler and pressure vessel types **Subgroup:** Inspection **Task Group:** None assigned. **Submitted by:** V. Scarcella **Explanation of Need:** This would get states using the standard across the country both from a violation and object type.		
July 2025 Meeting Action:		

Item Number: 25-32	**NBIC Location: Part 2, New Supplement**	**No Attachment**
General Description: Referenced standards added supplement to NBIC Part II **Subgroup:** Inspection **Task Group:** None assigned. **Submitted by:** V. Scarcella **Explanation of Need:** Need working group to review and propose appropriate action.		
July 2025 Meeting Action:		

Item Number: 25-36	**NBIC Location: Part 2, S8.2**	**Attachment Page 32**
General Description: Relief valve differential percentage conflict. **Subgroup:** Inspection **Task Group:** None assigned. **Submitted by:** I. McGregor **Explanation of Need:** Clarification is needed to ensure a correct assessment of the recommended differential pressure percentage between the operating pressure and lifting pressure of the pressure relief valve. When making formal recommendations for corrective action due to high operating pressure differentials observed during inspections, the correct recommended value is needed to guide the adjustments necessary.		
July 2025 Meeting Action:		

Item Number: 25-37	**NBIC Location: Part 2, Forms**	**Attachment Page 33**
General Description: Minor changes to NBIC Part 2 forms **Subgroup:** Inspection **Task Group:** None assigned. **Submitted by:** V. Scarcella **Explanation of Need:** Minor changes to NBIC Part 2 forms		
July 2025 Meeting Action:		

13. Future Meetings

- January 12-15, 2026 – New Orleans, LA

14. Adjournment

Respectfully submitted,

Jodi Metzmaier
Subcommittee Inspection Secretary

THE NATIONAL BOARD
OF BOILER AND PRESSURE VESSEL INSPECTORS

Subject:	Overriding Part 2 Inspection Requirements with RBI Program
NBIC Location:	2023 NBIC, Part 2, 4.4.7.3 and 4.5.3 b)
Statement of Need:	There needs to be some clarity on whether an RBI program has the ability to override some of the inspection requirements listed in Part 2 as long as all jurisdictional requirements are met.
Background Information:	NBIC Part 2, Section 4, Para. 4.5.3 specifically states that one of the benefits of having an RBI program is to identify items that do not require inspection or mitigation. However, NBIC Part 2, Section 4, Para. 4.4.7.3 states that PRIs in non-corrosive service are required to have thickness measurements taken.
Proposed Question:	If a company has an established RBI program and has deemed a PRI to be in non-corrosive service through an RBI assessment, can the company choose to omit the thickness measurements called out in Part 2, Section 4, Para. 4.4.7.3 as long as all jurisdictional requirements are met?
Proposed Reply:	Yes.
Committee's Question:	<Question(s) the committee will interpret. Can be the same wording as the proposed question>
Committee's Reply:	<Yes or no response>
Rationale:	<Additional clarification for response>

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Subject:	Interpretation request into the NBBI for the NB-23 2023 paragraph 2.3.6.2
NBIC Location:	2025 NBIC Part 2, 2.3.6.2 b) 2) a. 3.
Statement of Need:	Numerous air receivers are found to be less than the required wall thickness.
Background Information:	https://www.dir.ca.gov/dosh/pressure.html CAL-OSHA Circular Letter PV-2017-1 It is permissible to take a 10% reduction of the nameplate or data report thick § 462. Field Inspections and Reports. (a) (1) Thickness determinations indicating significant reduction in the material thickness over a general area (National Board Inspection Code Par. U-107 may be used as a guide) shall be shown on the inspection report as well as the calculations for the reduction in the allowable working pressure.
Proposed Question:	If there is general uniform wall thinning where the thinnest point is not less than 75% of the required wall thickness, is the required average wall thickness required to be at least the minimum required wall thickness?
Proposed Reply:	No.
Committee's Question:	<Question(s) the committee will interpret. Can be the same wording as the proposed question>
Committee's Reply:	<Yes or no response>
Rationale:	<Additional clarification for response>

NBIC Life Extension/Continuation Testing of ASME High Pressure Carbon Fiber Reinforced Plastic (CFRP) Section X Class III Pressure Vessels

General

An ASME CFRP vessel without inflicted damage from external forces is quite a robust structure with a very long fatigue life. Until recently, ASME Section X Class III CFRP pressure vessels had a 20-year service life limit. That limitation has been removed. However, this vessel class has been in use for less than 20 years and it is important to assess and verify the safety of these vessels considering the gases could be at 15,000 psi or over 1,000 bar. The procedure herein describes how to do modal acoustic emission (MAE) testing of ASME Section X Class III CFRP vessels in order to determine if the service life can be safely extended or continued beyond 20 years for up to an additional twenty (20) years beyond the date of manufacture listed on the vessel's label. Life extension could be called life continuation for the newer vessels that have no specified life, however, life extension is the term used herein for both. Each extended life vessel is subject to requalification testing by MAE testing every five years in order to continue in service for up to 20 years.

Scope

This document applies to ASME Section X Class III CFRP pressure vessels. The vessels can be either fully overwrapped with a load-bearing liner (commonly called Type 3 vessels) or fully overwrapped with a non load-bearing (e.g., plastic) liner (commonly called Type 4 vessels).

References

ASNT-SNT-TC-1A (Recommended Practice Outlines for Qualification of Non-destructive Testing Personnel) or equivalent (e.g., ISO 9712) – Qualifications and certification of NDT personnel.

CGA C.6.2 (STANDARD FOR VISUAL INSPECTION AND REQUALIFICATION OF FIBER REINFORCED HIGH PRESSURE CYLINDERS) or ISO 11623, Gas Cylinders – Composite cylinders and tubes – Periodic inspection and testing.

ISO 19016 Gas cylinders — Cylinders and tubes of composite construction — Modal acoustic emission (MAE) testing for periodic inspection and testing.

ASME Section X Class III High Pressure CFRP Pressure Vessels Background

Many pressure vessels are fabricated by filament winding with carbon fiber reinforcement in an epoxy matrix. ASME vessels are fabricated under Section X, Mandatory Appendix 8. The materials, construction and testing procedures laid out in Appendix 8 must be followed carefully and thoroughly documented.

Once stressed, all composite materials will have internal characteristic damage states consistent with all the many studies found in the open literature on the subject. There will be both matrix damage and fiber damage caused by voids and other defects. Such characteristic damage does not compromise the use or safety of the vessels. Further, there are defects inherent in the fibers and it is well-known that these defects cause fibers (filaments) to fail (rupture) at different loads and times. Again, this is normal and expected behavior. What is not expected is the rupture of a large number of fibers (on the order of a tow or greater) simultaneously at the same position in a vessel. This requires a significant stress concentration of the kind caused by damage that has been inflicted on the vessel by external forces. If a significant stress concentration exists, it is possible for that stress concentration to reduce burst pressure to a value below that required by the safety factor.

Defects in carbon fibers are randomly distributed along the fibers and that carbon fiber strengths follow a Weibull probability distribution. Weaker fibers in a vessel will fail during proof testing after which very few fibers fail at operating pressure under normal service conditions. Stress concentrations that develop in service can cause fibers to fail during subsequent requalification testing. These are usually few in number and serve to relieve stress concentrations. They do not lessen the integrity of the vessel. Fibers normally begin to fail in large numbers once the pressure in the vessel exceeds around 90% of ultimate.

Well-manufactured CFRP pressure vessels are very robust because of the way a fiber break redistributes loads to neighboring fibers and even to the same fiber itself at a distance from a break called the ineffective fiber length. A broken fiber is unloaded only at the ruptured ends. Beyond the ineffective length the fiber is fully loaded again. This is the key reason that these vessels are so rugged and safe.

There are many possibilities for harming a pressure vessel, for example, fire damage. Other types of damage are cuts and impact. Experience, as well as many research studies, has shown that CFRP materials are essentially notch insensitive. For example, in an ISO notch test for Type 3 vessels an axial cut is made halfway through the depth of the cylindrical wall of the vessel with a length in the axial direction of five times the wall thickness. Extensive testing has shown that the effect of such a notch in a typical CNG tank is a burst pressure reduction of typically less than 20%. A CNG tank with an operating pressure of 3,600 psi and a safety factor of 2.25, must burst at 8100 psi or above. A typical design yields a burst pressure of around 10,000 psi, and, in such a case, a 20% reduction in burst pressure reduces the safety factor to just under the 2.25 requirement. The test described herein focuses on ensuring that vessels containing a stress concentration of 1.2 or more are removed from service.

Background for MAE

Note: ISO/TS 19016 contains much additional information on MAE testing, including definitions of terms, and is highly recommended.

Modal acoustic emission (MAE) testing is a type of acoustic emission test (AT) that attempts to make a direct connection between elastodynamic theory predictions of the waveform type, energy and frequency content expected from various damage mechanisms in materials. For this reason the stress waves are measured with absolutely calibrated broadband transducers. The waveforms are digitally captured and stored. Each waveform is analyzed to determine the type of damage event that produced it. For example, a fiber break stress wave can be distinguished from stress waves of other damage mechanisms found in CFRP composite materials. The ability to do this has been reduced to a set of rules in the case of CFRP pressure vessel testing and programmed in software to automatically identify sources and numbers, much as in other fields of acoustics such as SONAR. Research on the effects of various damage mechanisms has taken MAE testing even further. MAE testing is currently used for in-service requalification testing of high pressure CFRP pressure vessels used in transportation under USDOT and Transport Canada rules and regulations. It is also approved for life extension testing of self-contained breathing apparatus pressure vessels under USDOT rules and regulations. The accept/reject criteria use four MAE allowance factors F1, F2, M1 and M2, which are defined and described below.

MAE Allowance Factors and Accept/Reject Criteria

F1 the fiber rupture energy allowed during testing in any single MAE event. The single fiber break energy is calculated by the formula given in this document and divided into the MAE event energy. The number obtained is the number of fibers that ruptured in near proximity to one another simultaneously. The values of F1 for different vessel circumferences and test pressures are given in Table 1.

F2 is the largest single event energy. Delamination and frictional emission wave energies can be much greater than fiber break wave energies. F2 shall be set at 100 x F1.

M1 is the allowed energy rise in the background energy (BE). The background energy is the minimum energy in a windowed portion of the waveform.

M2 is the allowed peak to peak excursion between neighboring maxima and minima of an N point moving average calculated from all BE values.

It is well-known that production vessels have a range of burst pressures. This is driven by statistical variations in the materials and fabrication variables. In these vessels, the random distribution of defects in the materials leads to a statistical failure process.

The hoop fibers control the burst pressure. For example, an axially cut ISO notch cuts across tens or even hundreds of thousands of hoop fibers. A heavily notched vessel always fails at the notch if it is undamaged elsewhere. MAE testing detects fiber ruptures and counts the number of fiber breaks represented by the energy in each fiber break event during a pressure test.

In addition to direct detection of fiber breaks, the MAE test also determines if there is a rise and oscillation of the background energy (BE) level. Energy oscillations are caused when fibers under load rupture, release energy in the form of stress waves (acoustic emission) and their load is transferred through shear in the matrix to neighboring fibers. The rising pressure in a test provides the energy input for the oscillation process as the overloaded fibers fail and transfer their load. All pressure vessels exhibit continuing BEO at some point during pressurization to burst. There is a statistical nature to this process due to the randomness of defects. BEO is never expected at operating pressure or test pressure in a good vessel.

Another way MAE testing detects damage is through frictional emission. Frictional emission is caused by the rubbing of fracture surfaces against each other as the vessel is pressurized and depressurized. Frictional events can be very energetic, far surpassing the energies in fiber breaks. It is mostly detected at lower pressure upon pressurization and depressurization, particularly depressurization when the fracture surfaces are closing upon one another. Frictional emission is usually present and persistent in CFRP vessels even when there is no new damage. It is especially evident after impact damage has caused significant delamination in the vessel.

Personnel Qualifications

The person doing the type testing shall be a senior technical person (SRT – Senior Review Technologist) who holds a degree in mechanical engineering, physics or closely related engineering science discipline and who has extensive experience with MAE testing, plate wave theory, composite materials, laminated plate theory, composite failure models, damage types and their effects, as well as CFRP pressure vessel manufacturing, pressure testing and burst testing, or a Level III technician certified by ISO 9762 or equivalent (e.g., ASNT TC-1A) with equivalent knowledge and experience.

Requalification testing shall be conducted by a Level I or Level II or a person who holds a bachelor's degree in mechanical engineering or physics, and who is trained and under the direct supervision of the SRT or Level III.

General Test Procedure

MAE transducers shall be acoustically coupled to the vessel under test and connected to waveform recording equipment. Waveforms shall be recorded and stored on digital media as the vessel is pressurized. All analysis shall be done on the waveforms. The waveforms of interest are the E (Extensional Mode) and F (Flexural Mode) plate waves. Prior to pressurization, the velocities of the earliest arriving frequency in the E wave and the latest arriving frequency in the F wave shall be measured in the circumferential direction in order to characterize the material and set the sample time (the length of the wave window). The E and F waves shall be digitized and stored for analysis. The test pressure shall be recorded simultaneously with the MAE events.

Equipment

a) Testing System - A testing system shall consist of: 1) sensors; 2) preamplifiers; 3) high pass and low pass filters; 4) amplifiers; 5) A/D (analog-to-digital) converters; 6) a computer program for the collection of data; 7) computer and monitor for the display of data; and 8) a computer program for analysis of data.

Examination of the waveforms event by event shall always be possible and the waveforms for each event shall correspond precisely with the pressure and time data during the test. The computer program shall be capable of detecting the first arrival channel. This is critical to the acceptance criteria below.

Sensors and recording equipment shall be checked for a current calibration sticker or a current certificate of calibration.

b) Sensor Calibration

Sensors shall have a flat frequency response from 50 kHz to 400 kHz. Deviation from flat response (signal coloration) shall be corrected by using a sensitivity curve obtained with a Michelson interferometer calibration system similar to the apparatus used by NIST (National Institute for Standards and Technology). Sensors shall have a diameter no greater than 0.5 in. (13 mm) for the active part of the sensor face. The aperture effect shall be taken into account. Sensor sensitivity shall be at least 0.05 V/ nm.

c) Scaling Fiber Break Energy

The wave energy shall be computed by the formula:

$$U = \frac{1}{Z} \int V^2 \ dt$$

which is the formula for computing energy in the MAE signal, where V is the voltage in volts (V) and Z is the input impedance in ohms (Ω). A rolling ball impact setup shall be used to create an acoustical impulse in an aluminum plate. The measured energy in the wave shall be used to scale the fiber break energy. This scaling is illustrated later on.

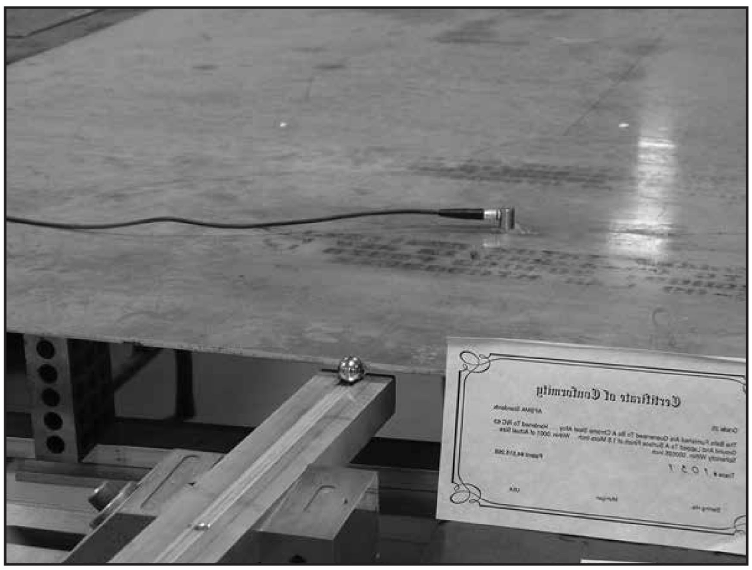

FIGURE 1. ROLLING BALL IMPACT CALIBRATION SETUP

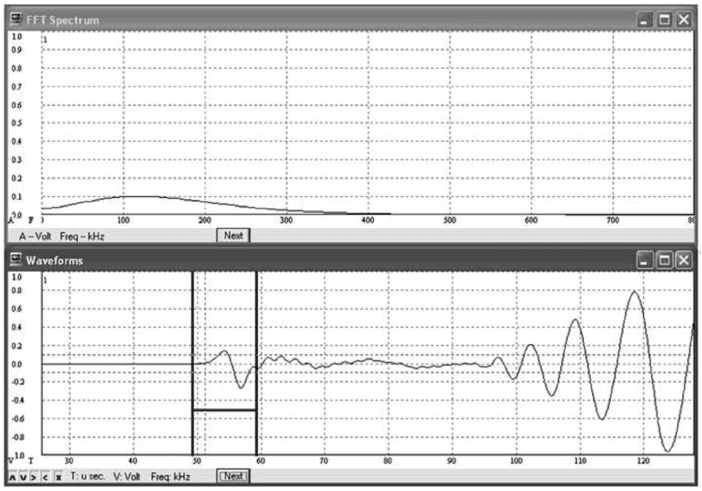

FIGURE 2. FRONT END WAVEFORM - The front end of waveform created by rolling ball impact calibration setup is shown in Figure 2. A Fast Fourier transform (FFT) shows that the center frequency of the first cycle is approximately 125kHz.

The impact setup, an example of which is shown in Figure 1, shall be arranged as follows. The steel ball shall be ½ inch (13 mm) in diameter. The steel ball is a type typically used in machine shops for measuring taper and is commercially available. The ball shall be made of chrome steel alloy hardened to R/C 63, ground and lapped to a surface finish of 1.5 micro-inch (0.0000381 mm), within 0.0001 inch (0.0025 mm) of actual size and sphericity within 0.000025 inch (0.00064 mm). The plate shall be made of 7075 T6 aluminum, be at least 4 ft x 4 ft (1200 mm X 1200 mm) in size, the larger the better to avoid reflections, be 1/8 inch (3.2 mm) in thickness and be simply supported by steel blocks. The inclined plane shall be aluminum with a machined square groove 3/8 inch (9.5 mm) wide which supports the ball and guides it to the impact point. The top surface of the inclined plane shall be positioned next to the edge of the plate and stationed below the lower edge of the plate such that the ball impacts with equal parts of the ball projecting above and below the plane of the plate. A mechanical release mechanism shall be used to release the ball down the plane.

The ball roll length shall be 12 inch (305 mm) and the inclined plane angle shall be 6 degrees. The impact produces an impulse that propagates to sensors coupled to the surface of the plate 12 inches (305 mm) away from the edge. The sensors shall be coupled to the plate with vacuum grease. The energy of the leading edge of the impulse, known as the wave front shall be measured. The vertical position of the ball impact point shall be adjusted gradually in order to “peak up” the acoustical signal, much as is done in ultrasonic testing where the angle is varied slightly to peak up the response. The center frequency of the first cycle of the E wave shall be confirmed as 125 kHz ± 10 kHz. See Figure 2. The energy value in joules of the first half cycle of the E wave shall be used to scale the fiber break energy, as illustrated there. This shall be an “end to end” calibration meaning that the energy shall be measured using the complete MAE instrumentation (sensor, cables, preamplifiers, amplifiers, filters and digitizer) that are to be used in the actual testing situation.

The energy linearity of the complete MAE instrumentation (sensor, cables, preamplifiers, amplifiers, filters and digitizer) shall be measured by using different roll lengths of 8, 12 and 16 inches (203, 305, and 406 mm).

The start of the E wave shall be from the first cycle of the waveform recognizable as the front end of the E wave to the end of the E wave which shall be taken as 10 microsecond (μs) later. (The time was calculated from the dispersion curves for the specified aluminum plate.) A linear regression shall be applied to the energy data and a goodness of fit R2 > 0.9 shall be obtained.

d) Preamplifiers and Amplifiers – low noise and high fidelity are important to achieve the required sensitivity.

e) Filters - A high pass filter of 20 kHz shall be used. A low pass filter shall be applied to prevent digital aliasing that occurs if frequencies higher than the Nyquist frequency (half the sampling rate) are in the signal.

f) A/D - The sampling speed and memory depth (wave window length) are dictated by the test requirements and calculated as follows: Vessel length = L inches (meters). Use C_E = 0.2 in./μs (5080 m/s) and C_F = 0.05 in./μs (1270 m/s), the speeds of the first arriving frequency in the E wave and last arriving frequency in the F wave, respectively, as a guide. The actual dispersion curves for the material shall be used if available.

L / C_E = T1 μs. This is when the first part of the direct E wave will arrive.

L / C_F = T2 μs. This is when the last part of the direct F wave will arrive.

(T2 – T1) x.1.5 is the minimum waveform window time and allows for pretrigger time.

The recording shall be quiescent before the front end of the E wave arrives. This is called a “clean front end”. The sampling rate, or sampling speed, shall be such that aliasing does not occur. A minimum of 2 MHz is recommended.

The recording system (consisting of all preamplifiers, amplifiers, filters and digitizers beyond the sensor) shall be calibrated by using a 20 cycle long tone burst with 0.1 V amplitude at 100, 200, 300, and 400 kHz. The system shall display an energy of

$$U = V^2\, NT/2Z \ (J)$$

at each frequency, where V=0.1 volts, N = 20, Z is the preamplifier input impedance in ohms (Ω) and T is the period of the cycle in seconds (s).

SENSOR PLACEMENT

At least two sensors shall be used in any MAE test regardless of vessel size so that electromagnetic interference (EMI) is easily detected by simultaneity of arrival. Sensors shall be placed at equal distances around the circumference of the vessel on the cylindrical portion of the vessel adjacent to the tangent point of the dome such that the distance between sensors does not exceed 24 in. (610 mm). Adjacent rings of sensors shall be offset by ½ a cycle. For example, if the first ring of sensors is placed at 0, 120, and 240 degrees, the second ring of sensors is placed at 60, 180, and 300 degrees. This pattern shall be continued along the vessel length at evenly spaced intervals, such intervals not to exceed 24 in. (610 mm) along the axis of the vessel, until the other end of the vessel is reached. See Figure 3. The diameter referred to is the external diameter of a vessel.

Maximum distance between sensors in the axial and circumferential directions shall not exceed 24 inches (609 mm) as measured along the cylinder axis. The diagonal distance created by offsetting every other row will be greater than 24 inches. This spacing allows for capturing the higher frequency components of the acoustic emission impulses and high channel count wave recording systems are readily available. If it is demonstrated that the essential data can still be obtained using a greater distance, and the authority having jurisdiction concurs, the spacing may be adjusted accordingly.

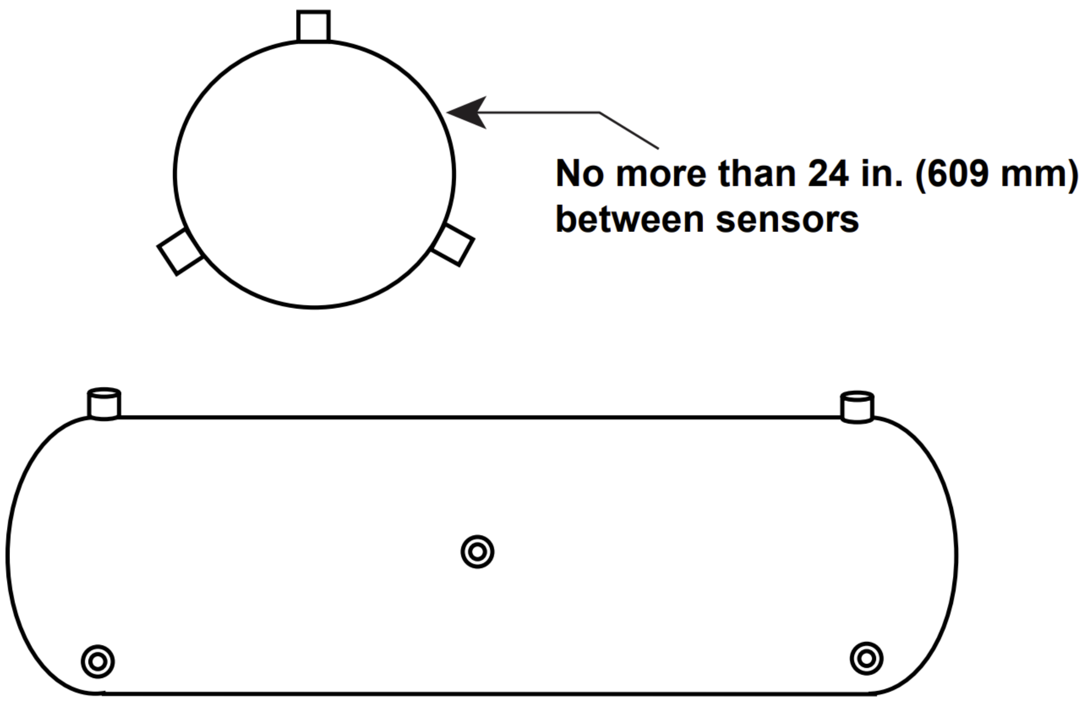

FIGURE 3. SENSOR SPACING AND PATTERN. No more than 24 in. (609 mm) between sensors as measured along the cylinder axis. The diagonal distance to neighboring sensors created by offsetting every other row will be greater than 24 inches.

Analysis Procedure and Accept/Reject Criteria

Before applying the evaluation procedure below all noise must be eliminated from the data set. Noise comes in many forms with characteristic features. See ISO 19016 for detailed information about the different types of noise waveforms. Only events with clean front ends shall be used for accept/reject evaluation.

a) In order to determine if fiber bundle breakage has occurred during the filling operation the frequency spectra of the direct E and F waves shall be examined and the energies in certain frequency ranges shall be computed as given below.

b) Definitions

Energies (U) in the ranges are defined as:

50 – 400 kHz: U0

100 – 200 kHz: U1

250 – 400 kHz: U2

The criteria for determining if high frequency spectrum events have occurred is given by the following formulas:

U0 ≥ (U_{FBB})

U2 / (U1 + U2) ≥ 15%

U2 / U0 ≥ 10%

U_{FBB} is the energy of a fiber bundle break calculated using the average breaking strength from the manufacturer's data or independent test data. The manufacturer's data shall be used if available. The formula that shall be used for calculating average fiber break energy in joules (J) is

$$U_{FB} = \frac{1}{2}(E * A * \delta * \varepsilon^2)$$

where E is the Young's modulus of the fiber in pascals (Pa), ε is the strain to failure of the fiber, A is area of the fiber in square meters (m2), and δ is the ineffective fiber length in meters (m) for the fiber and matrix combination. If the ineffective length is not readily available, ten (10) times the fiber diameter shall be used.

c) Example of Fiber Break Energy Calculation

Suppose d = 7 μm, E = 69.6 GPa and ε = 0.01 (average breaking strain) for some carbon fiber. Using A = πd2 /4 and δ = 10d,

$$U_{FB} = \frac{1}{2}(E * A * \delta * \varepsilon^2)$$

$$U_{FB} = 13.4 * \ 10^{-9}\ (J)$$

d) Example of Scaling Calculation

Suppose that the rolling ball impact (RBI) acoustical energy measured by a particular high fidelity MAE transducer is U^{AE}_{RBI} = 5 x 10-10 J and the impact energy U_{RBI} = 1.9 x 10-3 J (due to gravity). A carbon fiber with a break energy of U_{FB} = 13.4 x10^{-9} J would correspond to a wave energy of

U^{AE}_{FB} = U_{FB} x U^{AE}_{RBI} / U_{RBI}

U^{AE}_{FB} = 13.4 x10^{-9} J x 5 x 10^{-10} J / 1.9 x 10^{-3} J

U^{AE}_{FB} = 3.5 x 10^{-15} J.

This is the number that is used to calculate the value of U_{FBB} that is used in the fiber break criterion.

e) Amplifier Gain Correction All energies shall be corrected for gain. (20 dB gain increases apparent energy 100 times and 40 dB gain 10,000 times.)

f) Accept/Reject Criteria

Criterion 1: $U_{FBB} \leq F1 \times U_{FB}$, where U_{FB} has been calculated and scaled by the rolling ball impact energy as in the examples below. If this criterion is not met, significant fiber bundle break damage has occurred during the test and the vessel shall be removed from service.

Criterion 2. For a vessel to be acceptable no AE event shall have an energy greater than (F2) x U_{FB} at anytime during the test.

Criterion 3. Background energy of any channel shall not exceed 10 times the quiescent background energy of that channel.

Criterion 4. Any oscillation in background energy with a factor of two excursion between minima and maxima shows that the vessel is struggling to handle the pressure. Pressure shall be reduced immediately, and the vessel removed from service.

Table 1: MAE allowance factors for vessels with a 2.25 safety factor and 3,600 psi working pressure. Common vessel diameters (or circumferences) are given. Weibull parameters for the probability calculation were shape = 5 and scale = 508 ksi. Common winding pattern of OXOXO, where O=hoop and X=helical.

Fiber T700			
Working Pressure	3600 psi		
Test Pressure	5400 psi	4500 psi	
Circumference (in.)	F1	F1	
25.13	2500	1000	
50.26	10000	4200	
100.52	42000	17000	
157	104000	41000	

The allowance factors in Table 1 assume T700 carbon fiber in an epoxy matrix. Values for other carbon fibers can be calculated from material properties found in the open literature. The shape parameter is a measure of dispersion. The greater the dispersion in fiber strength, the more fibers that fail at lower pressures including test pressures. The scale parameter is a 30% knockdown of the published 5000 MPa (725 ksi) fiber strength.

NBIC Vessel Life Extension Information Form

This needs to be filled out only once and attached to the test form below for each vessel of the same type undergoing requalification for an additional five years beyond 20 years from the manufacturing date stated on the vessel's original label.

Fiber Manufacturer's data: Fiber strength, X __________ (Pa or psi)

Fiber Young's Modulus, E _______________ (Pa or psi)

Fiber Diameter, d ______________ (micron or in.)

Vessel overall length ______________ (cm or in.)

Vessel cylindrical section length ______________ (cm or in.)

Vessel circumference ________________________ (cm or in.)

Fiber Break Energy Calculation

The formula for fiber break energy shall be used

$U_f = (½\, X^2/E)(pi\, d^2/4)\delta$,

where E is fiber Young's modulus (Pa), X is fiber strength (Pa) , d is fiber diameter (m), pi is 3.14 and δ is the ineffective fiber length. If the ineffective length is unknown, a value of 10 shall be used.

Calculated value of fiber break energy U_f _______________ (Joule)

This value shall be input into the software for evaluating energies in waveforms of detected fiber breaks.

MAE Recording Equipment Data

Equipment Manufacturer__________________

Model Name/Number_____________________

Number of recording channels used _____________

Digitization Rate_____________ (must be equal or greater than 2 MHz)

Number of bits for A/D converter ___________________

Number of points per waveform ____________________

Number of pretrigger points per waveform______________

Note: The equivalent to discreet waveform data capture shall be produced by software if streaming capture is used. Must be capable of determining first arrival channel for every MAE event.

Has the equipment been calibrated? Date of Calibration______________

Calibration method? (Toneburst frequency = 100 kHz, number of cycles = 20 and voltage amplitude = 0.1 V) ____

Toneburst generator Model __________________________ Calibration date ______________

Calculated energy of calibration toneburst _____________ (Joule)

Measured energy of calibration toneburst ______________ (Joule)

Amplifier gain in addition to preamplifier gain to be used during testing __________ (dB)

Transducer Data

Transducer Manufacturer and Model Number _______________________________

Published bandwidth ___________________

Integral preamplifier? Y/N If yes, the gain is _________ (dB).

Transducers must be calibrated using the Rolling Ball Impact (RBI). They must also be absolutely calibrated using a Michelson Interferometer or other methods equivalent to ASTM E1106-12. Sensor sensitivity shall be at least 0.05 V/nm at the preamplifier input. MAE sensors shall have a diameter no greater than 0.5 inch for the active part of the face and the aperture effect shall be considered for MAE testing.

Calibration Date _____________

Is absolute calibration curve attached to this form? If not, testing shall not be performed.

Has transducer energy RBI conversion factor been measured? If not, testing shall not be performed.

Transducer energy conversion factor determined from RBI ______________

Transducer Spacing and Pattern

Standard pattern is no more than 24 inch intervals between sensors around the circumference and between rows of sensors on an axial line from one end of the cylindrical portion of the vessel to the other as specified earlier. Alternatively, attenuation measurements can made that allow a greater distance to be used between transducers in either the axial or circumferential directions provided that the frequencies necessary to determine fiber break events are detectable. This means the amplitude of the 400 kHz component of a 0.3mm 2H Pentel pencil lead break on the surface at one transducer is at least a factor of 1.4 above the noise level when measured at the nearest distant axial and circumferential transducers. The amplitude of the 400 kHz frequency component of the detected waveform shall be noted.

400 kHz amplitude at axial transducer spacing ____________________ (Volt)

400 kHz amplitude at circumferential transducer spacing ____________________(Volt)

Total number of transducers used in test _______________

Describe and provide a rough sketch below of the alternative spacing pattern to be used based on attenuation measurements.

Pressurization

Pressure shall be applied hydrostatically by a computer-controlled system. Proper precautions should be observed for test personnel safety.

A pressure output voltage shall be supplied to the MAE instrumentation according to the voltage level requirement of the MAE recording system.

Pressure gage type and model ___________________

MAE transducers shall be attached and checked for proper functioning either by recording pencil lead breaks or auto-sensor test results. The quiescent background energy shall be recorded automatically for every channel just before pressurization begins.

ASME Section X Class III Pressure Vessel Requalification/Life Extension Test Report Form

MAE Test Technician

Technician Name ____

Certification Agency and Certification Number ____

Or

Certifying Authority, Certification Level, and Certification Date

____

Vessel Data

Vessel Manufacturer ____

Date Manufactured _____________________________________

Operating Pressure ______________________________

Service (e.g., CNG, hydrogen) _____________________

Vessel Serial Number _____________________________

Date of last requalification test ___________________________

Visual Examination

Note: The VE must be performed prior to running an MAE test.

The VE procedure and accept/reject criteria can be found in Section X Mandatory Appendix 8.

VE performed by __________________________

Date _____________________________

Result (Pass or Fail. Note reason for failure.) ____

Test Procedure

The test shall be conducted with modern MAE equipment. Modern means that the equipment is automated to the point that the test technician is a running a software program that can compute and display live during the test any violation of the accept/reject criteria. The test technician shall verify that the values (numbers) of the criteria have been input into the software. The MAE instrumentation, including the MAE transducers, shall be fully calibrated as described earlier in this document. The MAE instrumentation shall be fully capable of all displays, waveform acquisition and storage as previously described.

The technician shall verify amplifier gain settings, waveform digitizer settings, have been properly input. The pressure gage input shall be verified as working properly. All required data capture and evaluation plots shall be displayed on the computer screen.

1. Verify each transducer has a current calibration document.

2. Record serial number (S/N) and calibration date for each transducer used in the test.

3. Verify all transducers are well-coupled mechanically and acoustically to the vessel.

4. An auto-sensor test shall be performed, and the acoustical response of each transducer shall be recorded by the computerized equipment. In case a transducer response is 6 dB below the average response level, the technician can recouple it and retest the response. If it is still not acceptable, it shall be replaced with a similar transducer and the new transducer's S/N and calibration date noted.

5. Connect pressure gage to MAE equipment and verify signal.

6. A leak check shall be performed at 10% of test pressure. Pressure shall be increased at a rate of not less than 10 psi/sec but not greater than 100 psi/sec. Pressurization rate shall not permit flow noise. Pressure shall be held at 125% of operating pressure for five minutes before proceeding to test pressure. Test pressure shall be held for fifteen minutes. Pressure shall be reduced to zero psi. After pressure is reduced to zero, a transducer coupling check should be performed (auto-sensor test) and documented.

Note: The vessel under test may still be in service. The test may be conducted by pressurizing pneumatically, in which case the MAE test pressure will be lower than the normal hydrostatic test pressure of 3/2 or 5/3 of working pressure. If the MAE test pressure is lower than that used in the type testing (for example, if fill pressure or developed pressure is used) the appropriate accept/reject criteria shall be provided by the SRT in writing and noted here.

The MAE computer shall display waveforms for each channel, events and pressure versus time, and background energy versus time. If an accept/reject violation occurs, the pressure shall be reduced, and the vessel rejected for life extension/continuation.

The following numbers shall be noted immediately following the MAE test:

The pressure at which the BE energy first rises by more than 2 times the quiescent background energy shall be noted. BE initial rise pressure ______________ (psi) and energy level _______________ (Joule). (If no rise, so state.) There shall be no rise in BE greater than 10 x the quiescent energy.

The pressure at which a fall and subsequent rise of the BE (called background energy oscillation or BEO) with a peak-to-peak energy greater than a factor of two (2) shall be noted. BEO Pressure _____________ (psi) (If no oscillation, so state.) There shall be no oscillations with a peak-to-peak energy greater than 2.

Highest event energy ______________ (Joule) Shall be less than F2 x Uf.

Highest fiber break event energy ____________ (Joule) Shall be less than F1 x Uf.

Do all the numbers meet the MAE A/R criteria? Yes/No (Circle one.)

7. All the waveforms for a vessel that fails shall be saved and provided to the SRT. The waveforms for a vessel that passes can be discarded, but the test displays at the final pressure showing that the accept criteria have been met shall be attached to this form, a copy of which shall be retained with the vessel records by the owner of the vessel. A copy shall be retained by the entity performing the test for a period of six (6) years.

8. A vessel that has passed shall have a label attached stating approval for continued service for five years.

THE NATIONAL BOARD
OF BOILER AND PRESSURE VESSEL INSPECTORS

Subject:	Need to restrict signatures to inspections for which the inspector was present
NBIC Location:	Part 2, 1.5.1
Statement of Need:	It has become practice in one jurisdiction for inspectors to sign inspection reports for apprentices.
Background Information:	

Proposed Text:

The inspector is required to be present during the inspection and should only sign documents pertaining to inspections at which they were in attendance.

PART 2, SECTION 1
INSPECTION — GENERAL REQUIREMENTS FOR INSERVICE INSPECTION OF PRESSURE-RETAINING ITEMS

1.5.1 INSERVICE INSPECTION ACTIVITIES

Any defect or deficiency in the condition, operating, and maintenance practices of a boiler, pressure vessel, piping system, and pressure relief devices noted by the Inspector shall be discussed with the owner or user at the time of inspection and recommendations made for the correction of such defect or deficiency shall be documented. Use of a checklist to perform inservice inspections is recommended. The inspector shall be present during the inspection and shall only sign documents pertaining to inspections which they performed.

THE NATIONAL BOARD
OF BOILER AND PRESSURE VESSEL INSPECTORS

Subject:	**Add guidance for tube sag allowance**
NBIC Location:	Part 2, 3.4.8a)
Statement of Need:	Inspectors were asking for clarification and better guidance. Item needs a working group to consider language.
Background Information:	This item was summitted on behalf of Patrick McGiveron, an inspector working for Chief Clark.

Proposed Text:

3.4.8 OVERHEATING

a) Overheating is one of the most serious causes of deterioration. Deformation and possible rupture of pressure parts may result.

b) Attention should be given to surfaces that have either been exposed to fire or to operating temperatures that exceed their design limit. It should be observed whether any part has become deformed due to bulging or blistering. If a bulge or blister reduces the integrity of the component or when evidence of leakage is noted coming from those defects, proper repairs must be made.

Subject:	**Fitness-for-service coordination with API 579-1/ASME FFS-1**
NBIC Location:	Part 2, Sections: 2.3.6.2 Compressed Air, 2.3.6.4 Liquid Ammonia, 4.4.7.2 Method for Estimating Inspection Intervals, 4.4.8 Evaluating Inspection Intervals, S7.8 Acceptance Criteria [for LPG]
Statement of Need:	Alert users about situations where acceptance criteria in Part 2 may be less strict than API 579-1/ASME FFS-1.
Background Information:	Portions of closed Item 23-17 didn't make it into the 2025 edition and also don't seem to have been folded into a broader effort on fitness for service, as of the January 2025 meeting.

Proposed Text:

2.3.6.2 COMPRESSED AIR VESSELS

a) Compressed air vessels include receivers, separators, filters, and coolers. Considerations of concern include temperature variances, pressure limitations, vibration, and condensation. Drain connections should be verified to be free of any foreign material that may cause plugging.

b) Inspection shall consist of the following:

1) Welds — Inspect all welds for cracking or gouging, corrosion, and erosion. Particular attention should be given to the welds that attach brackets supporting the compressor. These welds may fail due to vibration;

2) Shells/Heads — Externally, inspect the base material for environmental deterioration and impacts from objects. Hot spots and bulges are signs of overheating and should be noted and evaluated for acceptability. Particular attention should be paid to the lower half of the vessel for corrosion and leakage. For vessels with manways or inspection openings, an internal inspection should be performed for corrosion, erosion, pitting, excessive deposit buildup, and leakage around inspection openings. UT thickness testing may be used where internal inspection access is limited or to determine actual thickness when corrosion is suspected;

a. UT Acceptance Criteria. These may not meet API 579-1/ASME FFS-1, including near welds, supports, structural discontinuities, for less than 0.1-inch vessel-wall remaining, if brittle fracture is a concern, or possibly other circumstances.

1. For line or crevice corrosion, the depth of the corrosion shall not exceed 25% of the required wall thickness.

2. Isolated pits may be disregarded provided that their depth is not more than 50% of the required thickness of the pressure vessel wall (exclusive of any corrosion allowance), provided the total area of the pits does not exceed 7 sq. in. (4,500 sq. mm) within any 8 in. (200 mm) diameter circle, and provided the sum of their dimensions along any straight line within that circle does not exceed 2 in. (50 mm).

3. For a corroded area of considerable size, the thickness along the most critical plane of such area may be averaged over a length not exceeding 10 in. (250 mm). The thickness at the thinnest point shall not be less than 75% of the required wall thickness, and the average thickness shall meet API 579-1/ASME FFS-1.

b. If the corrosion exceeds any of the above criteria, the following options are available to the owner/user.

1. The owner/user may conduct a complete UT survey of the vessel to verify remaining vessel wall thickness.

2. The vessel shall be removed from service until the vessel is repaired by an "R" ~~stamp holder~~ Certificate Holder.

3. The vessel shall be removed from service until it can be de-rated to a lower MAWP subject to review and approval by the Jurisdiction.

4. A fitness-for service analysis is performed by a qualified organization.

5. The vessel is permanently removed from service.

3) Fittings and Attachments — Inspect all fittings and attachments for alignment, support, deterioration, damage, and leakage around threaded joints. Any internal attachments such as supports, brackets, or rings shall be visually examined for wear, corrosion, erosion, and cracks;

4) Operation — Check the vessel nameplate to determine the maximum allowed working pressure and temperature of the vessel. Ensure the set pressure of the safety valve does not exceed that allowed on the vessel nameplate and determine that the capacity of the safety valve is greater than the capacity of the compressor. Ensure there is a functioning manual or automatic condensate drain; and

5) Quick-Closure Attachments — Filter-type vessels usually have one quick-type closure head for making filter changes, see NBIC Part 2, 2.3.6.5.

2.3.6.4 LIQUID AMMONIA VESSELS

Vessels in liquid ammonia service are susceptible to stress corrosion cracking (SCC) [~~(~~see NBIC Part 2, 3.3.2 b)~~)~~] in areas of high stress. High-strength and coarse-grained materials seem to be more at risk of SCC than are fine-grained or more moderate strength materials, although no commonly used steels appear to be immune to the problem. Postweld heat treatment of new or weld-repaired vessels or cold formed heads is beneficial in reducing the incidence of SCC. The presence of 0.2% minimum water in the liquid ammonia also inhibits SCC. Any leak should be thoroughly investigated and the necessary corrective action initiated.

a) Internal inspection

   1) Where existing openings permit, perform a visual internal inspection of the vessel. Look for any obvious cracks (very advanced SCC) and note areas that are subject to high stress such as welds, welded repairs, head-to-shell transitions, sharp interior corners, and interior surfaces opposite external attachments or supports.

   2) Fittings, such as liquid level gage floats and excess flow valves, should be removed or otherwise protected from power buffing or light sandblasting when preparing the interior surface of the vessels for inspection.

   3) Vessels in services where liquid ammonia is used as a reactant or is being preheated/vaporized should be inspected for localized corrosion in the reaction or vaporizing zones.

b) Examination and detection of SCC

   1) All interior welds and highly stressed areas should be examined by the Wet Fluorescent Magnetic Particle Testing method (WFMT) using an A/C yoke for magnetization. Note that weld cracks are often transverse in orientation. It is extremely important to ensure that the NDE method used will disclose cracks in any orientation.

   2) If cracks are discovered, a calculation shall be made to determine what depth of grinding may be carried out for crack removal (without encroaching on the minimum thickness required by the original code of construction).

   3) Where possible, crack removal by grinding is the preferred method of repair. Since the stresses at the crack tips are quite high, even very fine cracking shall be eliminated.

   4) Where crack depth is such that removal requires welded repair, a weld procedure shall be employed that will minimize HAZ hardening and residual stresses. Welded repairs, regardless of the depth of the repair, shall be postweld heat treated. The use of alternative welding methods in lieu of PWHT is permitted. Any repairs required and associated postweld heat treatment shall be completed in accordance with NBIC Part 3.

   5) Re-inspection by WFMT after welded repair shall be done to ensure complete crack removal.

   6) It is not intended to inhibit or limit the use of other NDE evaluation methods. It is recognized that acoustic emission and fracture mechanics are acceptable techniques for assessing structural integrity of vessels. Analysis by fracture mechanics may be used to assess the structural integrity of vessels when complete removal of all ammonia stress cracks is not practical. If alternative methods are used, the above recommendation that all cracks be removed, even fine cracks, may not apply. In addition to NDE and repair of liquid ammonia vessels that are susceptible to SCC, it is acceptable to use fitness for service evaluation methods to determine acceptability of a pressure-retaining item to perform its intended function. These methods shall be consistent with NBIC Part 2, 4.4, *Methods To Assess Damage Mechanisms And Inspection Frequency For Pressure-Retaining Items*.

c) Inspection of parts and appurtenances

1) If valves or fittings are in place, check to ensure that these are complete and functional. Parts made of copper, zinc, silver, or alloys of these metals are unsuitable for ammonia service and shall be replaced with parts fabricated of steel or other suitable materials.

2) Check that globe valves are installed with the direction of flow away from the vessel.

3) Observe that excess flow valves are properly installed and in good repair.

4) Check that hydrostatic relief valves are installed in the system piping where required.

5) Piping shall be observed to be a minimum of Schedule 80 if threaded and Schedule 40 if welded. Seamless or ERW piping is acceptable. Type F piping shall not be used for ammonia service.

6) Fittings shall be forged or Class 300 malleable iron. Seal welding is permitted only with forged fittings.

7) The Inspector shall note the pressure indicated by the gage and compare it with other gages on the same system. If the pressure gage is not mounted on the vessel itself, it should be ascertained that the gage is installed on the system in such a manner that it correctly indicates actual pressure in the vessel.

8) The Inspector shall note the liquid level in the vessel by observing the liquid level gage or other liquid level indicating device.

d) Inspection of pressure relief devices

1) See NBIC Part 2, 2.5 for the inspection of pressure relief devices used to prevent the overpressure of liquid ammonia vessels. Pressure relief devices in ammonia service shall not be tested in place using system pressure. Bench testing or replacement is required, depending on the type of pressure relief device used.

2) The Inspector shall note the replacement date marked on vessel safety valves and piping system hydrostatic relief valves requiring replacement every five years.

e) External inspection of insulated vessels

1) Insulated pressure vessels can suffer from aggressive external corrosion that is often found beneath moist insulation. The Inspector should closely examine the external insulation scaling surfaces for cold spots, bulges, rust stains, or any unusual conditions in previous repair areas. Bulging or distorted insulation on refrigerated vessels may indicate the formation of ice patches between the vessel shell and insulation due to trapped moisture. Careful observation is also required where the temperatures of insulated vessels cycle continually through the freezing temperature range.

2) The lower half and the bottom portions of insulated vessels should receive special focus, as condensation or moisture may gravitate down the vessel shell and soak into the insulation, keeping it moist for long periods of time. Penetration locations in the insulation or fireproofing, such as saddle supports, sphere support legs, nozzles, or fittings should be examined closely for potential moisture ingress paths. When moisture penetrates the insulation, the insulation may actually work in reverse, holding moisture in the insulation and/or near the vessel shell.

3) Insulated vessels that are run on an intermittent basis or that have been out of service require close scrutiny. In general, a visual inspection of the vessel's insulated surfaces should be conducted once per year.

4) The most common and superior method to inspect for suspected corrosion under insulation (CUI) damage is to completely or partially remove the insulation for visual inspection. The method most commonly utilized to inspect for CUI without insulation removal is by x-ray and isotope radiography (film or digital) or by real-time radiography, utilizing imaging scopes and surface profilers. The real time imaging tools will work well if the vessel geometry and insulation thickness allows. Other less common methods to detect CUI include specialized electromagnetic methods (pulsed eddy current and electromagnetic waves) and long range ultrasonic techniques (guided waves).

5) There are also several methods to detect moisture soaked insulation, which is often the beginning for potential CUI damage. Moisture probe detectors, neutron backscatter, and thermography are tools that can be used for CUI moisture screening.

6) Proper surface treatment (coating) of the vessel external shell and maintaining weather-tight external insulation are the keys to prevention of CUI damage.

f) Acceptance criteria. These may not meet API 579-1/ASME FFS-1, including near welds, supports, structural discontinuities, for less than 0.1-inch vessel-wall remaining, if brittle fracture is a concern, or possibly other circumstances.

The following are the acceptance criteria for liquid ammonia vessels. Vessels showing indications or imperfections exceeding the conditions noted below are considered unacceptable.

1) Cracks

Cracks in the pressure vessel boundary (e.g., heads, shells, welds) are unacceptable. When a crack is identified, the vessel shall be removed from service until the crack is repaired by an "R" ~~Stamp holder~~ Certificate Holder or the vessel permanently removed from service. (See NBIC Part 3, *Repairs and Alterations*.)

2) Dents

When dents are identified that exceed the limits set forth below, the vessel shall be removed from service until the dents are repaired by an "R" ~~Stamp holder~~ Certificate Holder, a fitness for service analysis is performed, or the vessel permanently retired from service.

a. Dents in Shells

The maximum mean dent diameter in shells shall not exceed 10% of the shell diameter, and the maximum depth of the dent shall not exceed 10% of the mean dent diameter. The mean dent diameter is defined as the average of the maximum dent diameter and the minimum dent diameter. If any portion of the dent is closer to a weld than 5% of the shell diameter, the dent shall be treated as a dent in a weld area, as shown in b. below.

b. Dents in Welds

The maximum mean dent diameter on welds (i.e., part of the deformation includes a weld) shall not exceed 10% of the shell diameter. The maximum depth shall not exceed 5% of the mean dent diameter.

c. Dents in Heads

The maximum mean dent diameter on heads shall not exceed 10% of the shell diameter. The maximum depth shall not exceed 5% of the mean dent diameter. The use of a template may be required to measure dents on heads.

3) Bulges

When bulges are identified that exceed the limits set forth below, the vessel shall be removed from service until the bulges are repaired by an "R" ~~Stamp holder~~ Certificate Holder or a fitness for service analysis is performed, the vessel may also be permanently retired from service.

a. Bulges in Shells

If a bulge is suspected, the circumference shall be measured at the suspect location and at several places remote from the suspect location. The variation between measurements shall not exceed 1%.

b. ~~Dents~~Bulges in Heads [Already approved for 2025 edition.]

If a bulge is suspected, the radius of the curvature shall be measured by the use of templates. At any point the radius of curvature shall not exceed 1.25% of the diameter for the specified shape of the head.

4) Cuts or Gouges

When a cut or gouge exceeds 25% of the original wall thickness of the vessel, the vessel shall be removed from service until it is repaired by an "R" ~~Stamp Holder~~ Certificate Holder or a fitness-for-service analysis is performed. The vessel may also be permanently retired from service.

5) Corrosion

a. For line or crevice corrosion, the depth of the corrosion shall not exceed 25% of the original wall thickness.

b. Isolated pits may be disregarded provided that their depth is not more than 50% of the required thickness of the pressure vessel wall (exclusive of any corrosion allowance), provided the total area of the pits does not exceed 7 sq. in. (4,500 sq. mm) within any 8 in. (200 mm) diameter circle, and provided the sum of their dimensions along any straight line within that circle does not exceed 2 in. (50 mm).

c. For a corroded area of considerable size, the thickness along the most critical plane of such area may be averaged over a length not exceeding 10 in. (250 mm). The thickness at the thinnest point shall not be less than 75% of the required wall thickness, and the average thickness shall meet API 579-1/ASME FFS-1. When general corrosion is identified that exceeds the limits set forth in this paragraph, the pressure vessel shall be removed from service until it is repaired by an "R" ~~Stamp holder~~ Certificate Holder or a fitness-for-service analysis is performed, or the vessel may be permanently retired from service.

4.4.7.2 METHOD FOR ESTIMATING INSPECTION INTERVALS FOR EXPOSURE TO CORROSION

a) When the pressure-retaining item is exposed to service temperatures below the creep range, and the corrosion rate controls the remaining wall thickness of the pressure-retaining item, the inspection interval shall be calculated by the formula below or by other industry methods as accepted by the Jurisdiction.

$$\underset{\text{(years)}}{\text{remaining life}} = (t_{(actual)} - t_{(required)}) \,/\, \underset{\text{rate}}{\text{corrosion}}$$

$t_{(actual)}$ = thickness in inches (mm) measured at the time of inspection for the limiting section used in the determination of $t_{(required)}$.

$t_{(required)}$ = minimum allowable thickness in inches (mm) for the limiting section of the pressure-retaining item or zone. It shall be the greater of the following:

1) The calculated thickness, exclusive of the corrosion allowance, required for the pressure relieving device set pressure, static head, or other loading and design temperature; or

2) The minimum thickness permitted by the provision of the applicable section of the original code of construction.

Corrosion Rate = inches (mm) per year of metal removal as a result of corrosion.

b) Any suitable nondestructive examination method may be used to obtain thickness measurements, provided the instruments employed are calibrated in accordance with the manufacturer's specification or an acceptable national standard.

1) If suitably located existing openings are available, measurements may be taken through the openings.

2) When it is impossible to determine thickness by nondestructive means, a hole may be drilled through the metal wall and thickness gage measurements taken.

c) For new pressure-retaining items or PRIs for which service conditions are being changed, one of the following methods shall be employed to determine the probable rate of corrosion from which the remaining wall thickness, at the time of the next inspection, can be estimated:

1) The corrosion rate as established by data for pressure-retaining items in the same or similar service; or

2) If the probable corrosion rate cannot be determined by the above method, on-stream thickness determinations shall be made after approximately 1,000 hours of service. Subsequent sets of thickness measurements shall be taken after additional similar intervals until the corrosion rate is established.

d) Corrosion-Resistant Lining

When part or all of the pressure-retaining items have a corrosion-resistant lining, the interval between inspections of those sections so protected may be based on recorded experience with the same type of lining in similar service, but shall not exceed ten years, unless sufficient data has been provided to establish an alternative inspection interval. If there is no experience on which to base the interval between inspections, performance of the liner shall be monitored by a suitable means, such as the use of removable corrosion probes of the same material as the lining, ultrasonic examination, or radiography. To check the effectiveness of an internal insulation liner, metal temperatures may be obtained by surveying the pressure-retaining item with temperature measuring or indicating devices.

e) Two or More Zones

When a pressure-retaining item has two or more zones of pressure or temperature and the required thickness, corrosion allowance, or corrosion rate differ so much that the foregoing provisions give significant differences in maximum periods between inspections for the respective zones (e.g., the upper and lower portions of some fractionating towers), the period between inspections may be established individually for each zone on the basis of the condition applicable thereto, instead of being established for the entire vessel on the basis of the zone requiring the more frequent inspection.

f) Above-Ground Pressure Vessels

All pressure vessels above ground shall be given an external examination after operating the lesser of five years, or one quarter of remaining life, preferably while in operation. Alternative intervals resulting in longer periods may be assigned provided the requirements of this section have been followed. Inspection shall include determining the condition of the exterior insulation, the supports, and the general alignment of the vessel on its supports. Pressure vessels that are known to have a remaining life of over ten years or that are prevented from being exposed to external corrosion (such as being installed in a cold box in which the atmosphere is purged with an inert gas, or by the temperature being maintained sufficiently low or sufficiently high to preclude the presence of water), need not have the insulation removed for the external inspection. However, the condition of the insulating system and/or the outer jacketing, such as the cold box shell, shall be observed periodically and repaired if necessary.

g) Interrupted Service

1) The periods for inspection referred to above assume that the pressure-retaining item is in continuous operation, interrupted only by normal shutdown intervals. If a pressure-retaining item is out of service for an extended interval, the effect of the environmental conditions during such an interval shall be considered.

2) If the pressure-retaining item was improperly stored, exposed to a detrimental environment or the condition is suspect, it shall be given an inspection before being placed into service.

3) The date of next inspection, which was established at the previous inspection, shall be revised if damage occurred during the period of interrupted service.

h) Circumferential Stresses

For an area affected by a general corrosion in which the circumferential stresses govern the MAWP, the least thicknesses along the most critical plane of such area may be averaged over a length not exceeding:

1) The lesser of one-half the pressure vessel diameter, or 20 in. (500 mm) for vessels with inside diameters of 60 in. (1.5 m) or less; or

2) The lesser of one-third the pressure vessel diameter, or 40 in. (1 m), for vessels with inside diameters greater than 60 in. (1.5 m), except that if the area contains an opening, the distance within which thicknesses may be averaged on either side of such opening shall not extend beyond the limits of reinforcement as defined in the applicable section of the ASME Code for ASME Stamped vessels and for other vessels in their applicable codes of construction.

i) Longitudinal Stresses

If because of wind loads or other factors the longitudinal stresses would be of importance, the least thicknesses in a length of arc in the most critical plane perpendicular to the axis of the pressure vessel may be averaged for computation of the longitudinal stresses. The thicknesses used for determining corrosion rates at the respective locations shall be the most critical value of average thickness. The potential for buckling shall also be considered.

j) Local Metal Loss

These acceptance criteria may not meet API 579-1/ASME FFS-1, including near welds, supports, structural discontinuities, for less than 0.1-inch vessel-wall remaining, if brittle fracture is a concern, or possibly other circumstances.

Corrosion pitting shall be evaluated in accordance with NBIC Part 2, 4.4.8.7. Widely scattered corrosion pits may be left in the pressure-retaining item in accordance with the following requirements:

1) Their depth is not more than one-half the required thickness of the pressure-retaining item wall (exclusive of corrosion allowance);

2) The total area of the pits does not exceed 7 sq. in. (4,500 sq mm) within any 50 sq. inches (32,000 sq. mm); and

3) The sum of their dimensions (depth and width) along any straight line within this area does not exceed 2 in. (50 mm).

k) Weld Joint Efficiency Factor

When the surface at a weld having a joint efficiency factor of other than one is corroded as well as surfaces remote from the weld, an independent calculation using the appropriate weld joint efficiency factor shall be made to determine if the thickness at the weld or remote from the weld governs the maximum allowable working pressure. For the purpose of this calculation, the surface at a weld includes ~~1 in. (25 mm) on either side of the weld, or two times the minimum thickness on either side of the weld, whichever is greater~~ its heat-affected zone and also includes at least a weld band, centered on the weld, that has width of 2 in. (50.8 mm) or twice the furnished plate thickness, whichever is greater. For components with closely spaced openings and for background, see API 579-1/ASME FFS-1, Annex 2C.2.5 (2021 or later edition).

l) Formed Heads

1) When evaluating the remaining service life for ellipsoidal, hemispherical, torispherical or toriconical shaped heads, the minimum thickness may be calculated by:

a. Formulas used in original construction; or

b. Where the head contains more than one radii of curvature, the appropriate strength formula for a given radius.

2) When either integral or non-integral attachments exist in the area of a knuckle radius, the fatigue and strain effects that these attachments create shall also be considered.

m) Adjustments in Corrosion Rate

If, upon measuring the wall thickness at any inspection, it is found that an inaccurate rate of corrosion has been assumed, the corrosion rate to be used for determining the inspection frequency shall be adjusted to conform with the actual rate found.

n) Riveted Construction

For a pressure-retaining item with riveted joints, in which the strength of one or more of the joints is a governing factor in establishing the maximum allowable working pressure, consideration shall be given as to whether, and to what extent, corrosion will change the possible modes of failure through such joints. Also, even though no additional thickness may have originally been provided for corrosion allowance at such joints, credit may be taken for the corrosion allowance inherent in the joint design.

4.4.8 EVALUATING INSPECTION INTERVALS OF PRESSURE-RETAINING ITEMS EXPOSED TO INSERVICE FAILURE MECHANISMS

Pressure-retaining items are subject to a variety of inservice failure mechanisms that are not associated with corrosion. The following provides a summary of evaluation processes that may require a technical evaluation to assess resultant inspection intervals.

Some acceptance criteria in this section may not meet API 579-1/ASME FFS-1, including near welds, supports, structural discontinuities, for less than 0.1-inch vessel-wall remaining, if brittle fracture is a concern, or possibly other circumstances.

S7.8 ACCEPTANCE CRITERIA

The acceptance criteria for LPG pressure vessels is based on successfully passing inspections without showing conditions beyond the limits shown below. These acceptance criteria may not meet API 579-1/ASME FFS-1, including near welds, supports, structural discontinuities, for less than 0.1-inch vessel-wall remaining, if brittle fracture is a concern, or possibly other circumstances.

...

S7.8.2 DENTS

a) Shells

The maximum mean dent diameter in shells shall not exceed 5% of the shell diameter, and the maximum depth of the dent shall not exceed 5% of the mean dent diameter. The mean dent diameter is defined as the average of the maximum dent diameter and the minimum dent diameter. If any portion of the dent is closer to a weld than 5% of the shell diameter, the dent shall be treated as a dent in a weld area, see b) below.

b) Welds

The maximum mean dent diameter on welds (i.e., part of the deformation includes a weld) shall not exceed ~~10%~~ 5% of the shell diameter. The maximum depth shall not exceed 5% of the mean dent diameter.

c) Head

The maximum mean dent diameter on heads shall not exceed ~~10%~~ 5% of the shell diameter. The maximum depth shall not exceed 5% of the mean dent diameter. The use of a template may be required to measure dents on heads.

[Explanation for reviewers (not proposed text):
Allowed dent diameter near welds and in heads (higher risk locations) should not be twice the 5% allowed for shells, in paragraph (a) above.
Alternative: replace these acceptance criteria with a reference to API 579-1/ASME FFS-1.]

...

S7.8.4 CUTS OR GOUGES

When a cut or a gouge exceeds 25% of the original wall thickness of the pressure vessel, the pressure vessel shall be removed from service until it is repaired by a qualified repair organization or permanently removed from service.

...

Subject:	Relief valve differential percentage conflict.
NBIC Location:	Part 2, S8.2
Statement of Need:	Clarification is needed to ensure a correct assessment of the recommended differential pressure percentage between the operating pressure and lifting pressure of the pressure relief valve. When making formal recommendations for corrective action due to high operating pressure differentials observed during inspections, the correct recommended value is needed to guide the adjustments necessary.
Background Information:	HWH boilers observed in the field sometimes operate in excess of this differential and close to the relief valve setpoint. The conflict in example b) shows a 20 percent differential, not the apparently intended 25 percent in the introductory paragraph.

Proposed Text:

S8.2 HOT-WATER HEATING BOILERS
For hot-water heating boilers, the recommended pressure differential between the pressure relief valve set pressure and the boiler operating pressure should be at least 10 psi (70 kPa), or 25% of the boiler operating pressure, whichever is greater. Two examples follow:

a) If the pressure relief valve of a hot-water heating boiler is set to open at 30 psi (200 kPa), the boiler operating pressure should not exceed 20 psi (140 kPa).

b) If the pressure relief valve of a hot water heating boiler is set to open at 100 psi (700 kPa), the boiler operating pressure should not exceed 75~~80~~ psi (~~550~~ 515 kPa). Section IV of the ASME Code does not require that pressure relief valves used on hot water heating boilers have a specified blowdown. Therefore, to help ensure that the pressure relief valve will close tightly after opening and when the boiler pressure is reduced to the normal operating pressure, the pressure at which the valve closes should be well above the operating pressure of the boiler.

FORM NB-4
NEW BUSINESS OR DISCONTINUANCE
USED BY AUTHORIZED INSPECTION AGENCIES

To: ______________________________ JURISDICTION

______________________________ 1. DATE OF SERVICE

2. Notice of: ☐ New business ☐ Discontinuance or cancellation ☐ Refusal to inspect

3. Effective date ______________

4. Type of object: ☐ High pressure boiler ☐ Low pressure boiler ☐ Pressure vessel

5. OBJECT	6. OWNER'S NO.	7. JURISDICTION NO.	8. NATIONAL BOARD NO.	9. NAME OF MANUFACTURER

10. NAME OF OWNER

11. NAME OF OWNER INCLUDING COUNTY

12. LOCATION OF OBJECT INCLUDING COUNTY

13. USER OF OBJECT (IF SAME AS OWNER SHOW "SAME")

14. DATE OF LAST CERTIFICATE INSPECT., IF ANY	15. CERTIFICATE ISSUED	16. REASON FOR DISCONTINUANCE OR CANCELLATION
	☐ Yes ☐ No	☐ Phys. Condition ☐ Out of use ☐ Other

17. ~~REMARKS~~ (USE REVERSE SIDE)
INSPECTORS NARRATIVE

18. BY: ______________________________
INSPECTION AGENCY REP. BRANCH OFFICE

This form may be obtained from The National Board of Boiler and Pressure Vessel Inspectors, 1055 Crupper Ave., Columbus, OH 43229

NB-4 Rev. 2

FORM NB-5 BOILER OR PRESSURE VESSEL DATA REPORT

FIRST INTERNAL INSPECTION

Standard Form for Jurisdictions Operating Under the ASME Code

Complete When Not Registered National Board

1	DATE INSPECTED MO | DAY | YEAR	CERT EXP DATE MO | YEAR	CERTIFICATE POSTED ☐ Yes ☐ No	OWNER NO.	JURISDICTION NUMBER	NAT'L BD NO. ☐	OTHER NO. ☐
2	OWNER				NATURE OF BUSINESS	KIND OF INSPECTION ☐ Int ☐ Ext	CERTIFICATE INSPECTION ☐ Yes ☐ No
	OWNER'S STREET ADDRESS NUMBER				OWNER'S CITY	STATE	ZIP
3	USER'S NAME - OBJECT LOCATION				SPECIFIC LOCATION IN PLANT	OBJECT LOCATION - COUNTY	
	USER'S STREET ADDRESS NUMBER				USER'S CITY	STATE	ZIP
4	CERTIFICATE COMPANY NAME				CERTIFICATE COMPANY CONTACT NAME	EMAIL	
	CERTIFICATE COMPANY ADDRESS				CERTIFICATE COMPANY CITY	STATE	ZIP
5	TYPE ☐ FT ☐ WT ☐ CI ☐ AIR TANK ☐ WATER TANK Other			YEAR BUILT	MANUFACTURER	YEAR INST	☐ New ☐ Secondhand
6	USE ☐ Power ☐ Process ☐ Steam Htg ☐ HWH ☐ HWS ☐ Storage ☐ Heat Exchange ☐ Other ______				FUEL (BOILER)	METHOD OF FIRING (BOILER)	PRESSURE GAGE TESTED ☐ Yes ☐ No
7	PRESSURE This Inspection ______ Prev. Inspection ______			SAFETY-RELIEF VALVES Set at ______	EXPLAIN IF PRESSURE CHANGED		
8	IS CONDITION OF OBJECT SUCH THAT A CERTIFICATE MAY BE ISSUED? ☐ Yes ☐ No (If no, explain fully on back of form - listing code violation)					PRESSURE TEST ☐ Yes ______ psi Date ______ ☐ No	
9	SHELL No.	DIAMETER ☐ ID in. ☐ OD	OVERALL LENGTH ft. in.	THICKNESS in.	TOTAL HTG SURFACE (BOILER) Sq. Ft.	MATERIAL ASME Spec Nos	
10	ALLOWABLE STRESS psi	BUTT STRAP Thks in ☐ Single ☐ Double		HEADERS - WT BOILERS Thickness in.	TYPE ☐ Box ☐ Sinuous ☐ Wtr Wall ☐ Other ______		
11	TYPE LONGITUDINAL SEAM ☐ Lap ☐ Butt ☐ Welded ☐ Brazed ☐ Riveted			RIVETED Dia Hole in.	PITCH in. X in. X in.	SEAM EFF %	
12	HEAD THICKNESS in.	HEAD TYPE ☐ Plus ☐ Minus ☐ Fixed ☐ Flat ☐ Movable ☐ Quick Opening		RADIUS DISH in.	ELLIP RATIO	BOLTING No. Dia. in. Material ______	
13	TUBE SHEET THICKNESS in.	TUBES No. Dia. in. Length ft. in.			PITCH (WT BLRS) in. X in.	LIGAMENT EFF %	
14	**FIRE TUBE BOILERS**	DISTANCE UPPER TUBES TO SHELL Front in. Rear in.		STAYED AREA FRONT HEAD { Above Tubes ______ Below Tubes ______	REAR HEAD { Above Tubes ______ Below Tubes ______		
	STAYS ABOVE TUBES Front No. Rear No.		TYPE ☐ Head to Head ☐ Diagonal ☐ Welded ☐ Weldless		AREA OF STAYS Front Rear		
	STAYS BELOW TUBES Front No. Rear No.		TYPE ☐ Head to Head ☐ Diagonal ☐ Welded ☐ Weldless		AREA OF STAYS Front Rear		
15	FURNACE - TYPE Adamson (No. Sect ______) ☐ Corrugated ☐ Plain ☐ Other			THICKNESS in.	TOTAL LENGTH ft. in.	TYPE LONG. SEAM ☐ Welded ☐ Riveted ☐ Seamless	
16	STAYBOLTS - TYPE Threaded Welded Hollow Drilled (Size Hole ______ in.)			DIAMETER in.	PITCH in. X in.	NET AREA sq. in.	
17	SAFETY-RELIEF VALVES No. Size	TOTAL CAPACITY ______ Cfm ______ Lb/Hr ______ Btu/Hr		OUTLETS No. Size	PROPERLY DRAINED ☐ Yes ☐ No (*If no, explain on back of form*)		
18	**STOP VALVES**	ON STEAM LINE ☐ Yes ☐ No	ON RETURN LINES ☐ Yes ☐ No	OTHER CONNECTIONS ☐ Yes ☐ No	STEAM LINES PROPERLY DRAINED ☐ Yes ☐ No (*If no, explain on back of form*)		
19	FEED PIPE Size in.	FEED APPLIANCES No.	TYPE DRIVE ☐ Steam ☐ Motor	**CHECK VALVES**	FEED LINE ☐ Yes ☐ No	RETURN LINE ☐ Yes ☐ No	
20	WATER GAGE GLASS No.	TRY COCKS No.	BLOWOFF PIPE Size in. Location	INSPECTION OPENINGS COMPLY WTH CODE ☐ Yes ☐ No (*If no, explain on back of form*)			
21	CAST-IRON BOILERS Length ______ in. Width ______ in. Height ______ in.		SECTIONS No.	DOES WELDING ON STEAM, FEED BLOWOFF AND OTHER PIPING COMPLY WITH CODE? ☐ Yes ☐ No (*If no, explain on back of form*)			
22	SHOW ALL CODE STAMPING ON BACK OF FORM. Give details (use sketch) for special objects NOT covered above - such as double wall vessels, etc.			DOES ALL MATERIAL OTHER THAN AS INDICATED ABOVE COMPLY WITH CODE? ☐ Yes ☐ No (*If no, explain on back of form*)			
23	NAME AND TITLE OF PERSON TO WHOM REQUIREMENTS WERE EXPLAINED:						
24	I HEREBY CERTIFY THIS IS A TRUE REPORT OF MY INSPECTION Signature of Inspector	IDENT NO.	EMPLOYED BY		IDENT NO.		

This form may be obtained from The National Board of Boiler and Pressure Vessel Inspectors, 1055 Crupper Ave., Columbus, OH 43229

NB-5 Rev. 1

~~OTHER CONDITIONS AND REQUIREMENTS~~

INSPECTORS NARRATIVE

CODE STAMPING

(BACK)

FORM NB-6 BOILER-FIRED PRESSURE VESSEL REPORT OF INSPECTION

Standard Form for Jurisdictions Operating Under the ASME Code

1. DATE INSPECTED: ____________ (Month/Day/Year) CERTIFICATE EXPIRATION DATE: ____________ (Month/Day/Year) CERTIFICATE POSTED: ☐ YES ☐ NO

USER NUMBER: ____________ NAT'L BD NUMBER ☐ OR SERIAL # (IF CAST IRON) ☐ ____________

FIRST INSPECTION: YES ☐ NO ☐ JURISDICTION NUMBER: ____________

NATIONAL BOARD NUMBER: ____________ OTHER NUMBER: ____________

2. EQUIPMENT LOCATION NAME: ____________

EQUIPMENT LOCATION ADDRESS: ____________ (Equipment Location Street) ____________ (Equipment Location City)

____________ (Equipment Location State) ____________ (Equipment Location Zip Code)

NATURE OF BUSINESS: ____________

KIND OF INSPECTION: ☐ INTERNAL ☐ EXTERNAL CERTIFICATE RENEWAL: ☐ YES ☐ NO

3. CERTIFICATE BUSINESS NAME: ____________

CERTIFICATE CONTACT: ____________ (NAME) ____________ (Email)

CERTIFICATE MAILING ADDRESS: ____________ (Certificate Mailing Street) ____________ (Certificate Mailing City)

____________ (Certificate Mailing State) ____________ (Certificate Mailing Zip Code)

4. INVOICE BUSINESS: ____________ (Name)

CERTIFICATE INVOICE CONTACT: ____________ (Name) ____________ (Email)

INVOICE ADDRESS: ____________ (Invoice Address Street) ____________ (Invoice Address City)

____________ (Invoice Address State) ____________ (Certificate Mailing Zip Code)

5. TYPE: ☐ FT ☐ WT ☐ CI ☐ OTHER: ____________ ASME/OTHER CODE: ____________

MANUFACTURER: ____________ YEAR BUILT: ____________

MANHOLE ☐ HANDHOLE ☐ NEITHER ☐ CERTIFICATE DURATION (MONTHS): ____________

6. USE: ☐ POWER ☐ PROCESS ☐ STEAM HEATING ☐ HWH ☐ HWS ☐ OTHER

FUEL TYPE: ____________ METHOD OF FIRING: ____________

LOCATION IN PLANT: ____________

7. LOW WATER CUTOFF INSTALLED: YES ☐ NO ☐ TESTED: YES ☐ NO ☐

HIGH LIMIT TEMP/PRESSURE INSTALLED: YES ☐ NO ☐ WAS BOILER FIRED: YES ☐ NO ☐

COMBUSTION CONTROLS: CSD-1 ☐ NFPA ☐ OTHER ☐ ______

COMBUSTION AIR VERIFIED: YES ☐ NO ☐

8. ARE THERE ANY KNOWN OUTSTANDING (OPEN) VIOLATIONS FOR THIS EQUIPMENT? ☐ YES ☐ NO (IF YES, EXPLAIN FULLY UNDER ADVERSE CONDITIONS FOUND)

LOG/RECORD REVIEW: YES ☐ NO ☐

PRESSURE TEST: ☐ YES PSI: ______ DATE: ______ ☐ NO

9. STAMPED MAWP: ______ MINIMUM PRD REQUIRED CAPACITY: ______

NUMBER OF PRD'S: ______ TOTAL CAPACITY: ______

SET PRESSURE: ______ CAPACITY: ______

SET PRESSURE: ______ CAPACITY: ______

SET PRESSURE: ______ CAPACITY: ______

10. ~~INSPECTORS COMMENTS~~: (Verify any repairs were completed by a qualified repair company, and when applicable, the proper repair/ alterations forms are completed.)

INSPECTORS NARRATIVE

______

11. ~~ADVERSE CONDITIONS FOUND~~: ______

CONDITIONS TO BE ADDRESSED

______

12. REQUIREMENTS: ______

13. PERSON TO WHOM REQUIREMENTS WERE EXPLAINED: ______ (Name) ______ (Title)

______ (Email) ______ (Phone Number)

14. I HEREBY CERTIFY THIS IS A TRUE REPORT OF MY INSPECTION:

NB COMMISSION NUMBER: ______ EMPLOYED BY: ______

IDENTIFICATION NUMBER: ______ SIGNATURE OF INSPECTOR: ______

FORM NB-7 PRESSURE VESSELS REPORT OF INSPECTION

Standard Form for Jurisdictions Operating Under the ASME Code

1. DATE INSPECTED: ______ (Month/Day/Year) m/d/yyyy CERTIFICATE EXPIRATION DATE: ______ (Month/Day/Year) m/d/yyyy CERTIFICATE POSTED: ☐ YES ☐ NO

USER NUMBER: ______ JURISDICTION NUMBER: ______

NATIONAL BOARD NUMBER: ☐ OR SERIAL NUMBER: (IF CAST IRON) ☐ ______

FIRST INSPECTION: YES ☐ NO ☐

2. EQUIPMENT LOCATION NAME: ______

NATURE OF BUSINESS: ______

KIND OF INSPECTION: ☐ INTERNAL ☐ EXTERNAL CERTIFICATE RENEWAL: ☐ YES ☐ NO

3. EQUIPMENT LOCATION ADDRESS: ______ (Equipment Location Street) ______ (Equipment Location City)

______ (Equipment Location State) ______ (Equipment Location Zip Code)

4. CERTIFICATE BUSINESS NAME: ______

CERTIFICATE CONTACT: ______ (NAME) ______ (Email)

5. CERTIFICATE MAILING ADDRESS: ______ (Certificate Mailing Street) ______ (Certificate Mailing City)

______ (Certificate Mailing State) ______ (Certificate Mailing Zip Code)

6. INVOICE BUSINESS: ______ (Name)

CERTIFICATE INVOICE CONTACT: ______ (Name) ______ (Email)

7. INVOICE ADDRESS: ______ (Invoice Address Street) ______ (Invoice Address City)

______ (Invoice Address State) ______ (Certificate Mailing Zip Code)

8. TYPE: AIRTANK ☐ WATER TANK ☐ OTHER: ☐ ______ ASME/OTHER CODE: ______

MANUFACTURER: ______ YEAR BUILT: ______

MANHOLE ☐ HANDHOLE ☐ NEITHER ☐ CERTIFICATE DURATION (MONTHS): ______

9. USE: ☐ STORAGE ☐ PROCESS ☐ HEAT EXCHANGE ☐ OTHER: ______

HORIZONTAL ☐ VERTICAL ☐ LENGTH: ______ DIAMETER: ______

10. STAMPED MAWP: ______________________ MINIMUM PRD REQUIRED CAPACITY: ______________________

NUMBER OF PRD'S: ____________ TOTAL CAPACITY: ____________

SET PRESSURE: ____________ CAPACITY: ____________

SET PRESSURE: ____________ CAPACITY: ____________

SET PRESSURE: ____________ CAPACITY: ____________

OVERPRESSURE PROTECTION BY SYSTEM DESIGN: ☐ SIZE (ft^3 or Gallons): ______________________

11. ARE THERE ANY KNOWN OUTSTANDING (OPEN) VIOLATIONS FOR THIS EQUIPMENT? ☐ YES ☐ NO (IF YES, EXPLAIN FULLY UNDER ADVERSE CONDITIONS FOUND)

PRESSURE TEST: YES ☐ PSI ________ Date ________ (m/d/yyyy) NO ☐

INSPECTORS NARRATIVE

12. ~~INSPECTORS COMMENTS~~: (Verify any repairs were completed by a qualified repair company, and when applicable, the proper repair/alterations forms are completed.)

13. ~~ADVERSE CONDITIONS FOUND~~: **CONDITIONS TO BE ADDRESSED**

14. REQUIREMENTS:

15. PERSON TO WHOM REQUIREMENTS WERE EXPLAINED: ______________________ (Name) ______________________ (Title)

______________________ (Email) ______________________ (Phone Number)

16. I HEREBY CERTIFY THIS IS A TRUE REPORT OF MY INSPECTION:

NB COMMISSION NUMBER: ______________________ EMPLOYED BY: ______________________

IDENTIFICATION NUMBER: ______________________ SIGNATURE OF INSPECTOR: ______________________