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Virtual Conference
January 19-20, 2022

Office of Nuclear Reactor Regulation

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Abstract

The 2022 14th ASME/NRC OM Code Symposium, jointly sponsored by the American Society of Mechanical Engineers and the U.S. Nuclear Regulatory Commission, provides a forum for exchanging information on technical, programmatic, and regulatory issues associated with inservice testing programs at nuclear power plants, including the design, operation and testing of valves, pumps, and dynamic restraints. The symposium provides an opportunity to discuss improvements in design, operation, and testing of valves, pumps, and dynamic restraints that help to ensure their reliable performance. The participation of industry representatives, regulatory personnel, and consultants ensures the presentation of a broad spectrum of ideas and perspectives on the improvement of testing programs and methods for valves and pumps at nuclear power plants.

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The Steering Committee, American Society of Mechanical Engineers (ASME), and the U.S. Nuclear Regulatory Commission (NRC) gratefully acknowledge the efforts of the opening session speakers, session chairs, and authors for their invaluable contribution to the success of the symposium. We recognize the contribution of international representatives in providing a broad perspective to the valve and pump issues under consideration in the United States. We sincerely appreciate the excellent work of Mr. Oliver Martinez of ASME in coordinating the symposium. Our thanks also go to the NRC publications staff and technical editors for their extensive efforts in preparing the symposium proceedings.

Disclaimer

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The views expressed in these proceedings are those of the individual authors and do not necessarily reflect the views or policies of the U.S. Nuclear Regulatory Commission and other participating Federal agencies.

The papers have been copy edited and recast into a standard format. By consensus, English units have been used as an expression of current industry practice with metric units also indicated where possible.

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ASME Fellow, GSE TrueNorth
Former Chair of the ASME Operation and Maintenance Standards Committee

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U.S. Nuclear Regulatory Commission

Keynote Speaker:
Commissioner Jeff Baran
U.S. Nuclear Regulatory Commission

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Overview of NRC NUREG-1482, Revision 3, Guidelines for Inservice Testing at Nuclear Power Plants – Inservice Testing of Pumps and Valves, and Inservice Examination and Testing of Dynamic Restrains (Snubbers) at Nuclear Power Plants*

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*This paper was prepared by staff of the NRC. It may present information that does not currently represent an agreed-upon NRC staff position. The NRC has neither approved nor disapproved the technical content.

Abstract

The U.S. Nuclear Regulatory Commission (NRC) staff issued Revision 3 to NUREG-1482, "Guidelines for Inservice Testing at Nuclear Power Plants," to assist nuclear power plant licensees in establishing a basic understanding of the regulatory basis for pump and valve inservice testing (IST) programs and dynamic restraints (snubbers) inservice examination and testing programs. Since the issuance of Revision 2 to NUREG-1482, certain tests and measurements required by earlier editions and addenda of the American Society of Mechanical Engineers (ASME) *Operation and Maintenance of Nuclear Power Plants*, Division 1, OM Code: Section IST (OM Code) have been clarified, updated, or revised. The revision to NUREG-1482 and its Appendix A incorporates and addresses those changes, and includes the IST programs guidelines related to new reactors.

This revision includes a new Appendix B related to guidance for treatment of pumps, valves, and dynamic restraints (snubbers) during implementation of 10 CFR 50.69, "Risk-Informed Categorization and Treatment of Structures, Systems, and Components for Nuclear Power Plants." The revised guidance incorporates lessons learned and experience gained since the previous revision to NUREG-1482. This paper provides an overview of the contents of NUREG-1482 and those changes, and discusses how they affect NRC guidance on implementing pump and valve IST programs, and dynamic restraint (snubber) inservice examination, testing and service life monitoring programs. This paper highlights important changes to NUREG-1482, but is not intended to provide a complete record of all changes to the document. The NRC intends to continue to develop and improve its guidance on IST and inservice inspection (ISI) methods through active participation in the ASME OM Code consensus process; interactions with various

technical organization and user groups; and periodic updates of NRC-published guidance and issuance of generic communications as the need arises.

Introduction

The U.S. Nuclear Regulatory Commission (NRC) provides licensees with guidelines and recommendations for developing and implementing programs for the inservice testing of pumps and valves and inservice examination and testing of dynamic restraints (snubbers) at commercial nuclear power plants. In NUREG-1482, the staff discusses the regulations; the components to be included in an inservice testing (IST) program; and the preparation and content of cold shutdown justifications, refueling outage justifications, and requests for relief from and alternatives to the ASME OM Code requirements. The staff also gives specific guidance on relief and alternatives acceptable to the NRC and advises licensees on the use of this information at their facilities. The staff discusses the revised standard technical specifications (TS) for the IST program requirements and provides guidance on the process a licensee may follow upon finding an instance of noncompliance with the OM Code.

In the past, NRC staff issued this NUREG to assist the industry in eliminating unnecessary requests for relief and to provide guidelines and examples acceptable to the staff that might be useful to a licensee considering an alternative IST method to that required in the ASME OM Code. It is hoped that the guidance in NUREG-1482 will assist the industry in establishing a consistent IST approach. Implementation of the guidance is strictly voluntary and may change depending on advancements in technology or IST techniques. The NUREG also discusses some examples of the use of portions of later OM Code editions and addenda that licensees may implement if the related requirements stated in the applicable recommendations are met. The NRC guidance and recommendations provided in this NUREG do not supersede any regulatory inservice examination and testing requirements specified in Title 10 of the *Code of Federal Regulations* (10 CFR) 50.55a, “Codes and standards.”

Revision 3 to NUREG-1482 incorporates regulatory guidance applicable to the 2015 through 2017 Editions to the ASME OM Code. This paper is based on the 2015 through 2017 Editions of the ASME OM Code incorporated by reference in Section 50.55a, “Codes and standards,” in Title 10, “Energy,” of the *Code of Federal Regulations* (10 CFR 50.55a).

Specifically, the NRC staff is issuing Revision 3 to NUREG-1482 for the following reasons:

1. 10 CFR 50.55a Rule (Implemented August 2017)
    a. ASME OM Code 2009 Edition, 2011 Addenda, and 2012 Edition
        - New Appendix III, Motor-Operated Valves (MOVs)
        - Pyrotechnic-actuated (squib) valve surveillance for new reactors
    b. 10 CFR 50.55a conditions including
        - (b)(3)(i) on NQA-1 update
        - (b)(3)(ii) specifying Appendix III conditions for MOVs
            (A) 5-year or three refueling outage initial evaluation

            (B) impact on risk when extending high-risk MOV test intervals

            (C) risk categorization methods

            (D) MOV TS stroke time requirements

- (b)(3)(iii) specifying new reactor conditions for
  - (A) power-operated valve periodic verification
  - (B) check valve bidirectional testing
  - (C) flow-induced vibration
  - (D) operational readiness of pumps, valves, and dynamic restraints in high-risk non-safety systems (RTNSS) in reactors with passive core cooling systems
- (b)(3)(iv) specifying conditions on check valve condition monitoring (Appendix II)
- (b)(3)(vii) specifying ISTB conditions for pumps in current reactors
- (b)(3)(viii) specifying ISTE conditions for risk-informed IST programs
- (b)(3)(ix) specifying ISTF conditions for pumps in new reactors
- (b)(3)(x) specifying acceptance of OM Code Case OMN-20
- (b)(3)(xi) specifying supplemental conditions for valve position indication
- (f)(4) specifying OM Code IST program scope for Class 1, 2, and 3 pumps and valves, and use of augmented IST programs for non-Code safety-related pumps and valves

2. 10 CFR 50.55a Rule (Implemented June 3, 2020)
   a. 2015 and 2017 Edition of the OM Code
      - New Appendix IV (air-operated valves)
   b. OM Code Case Rulemakings
   c. OM Code Cases in Regulatory Guide (RG) 1.192, “Operation and Maintenance Code Case Acceptability, ASME OM Code,” incorporated by reference in 10 CFR 50.55a since issuance of NUREG 1482 Revision 2
   d. OM Code Cases being considered in current rulemaking and revision to RG 1.192
3. Incorporate IST operating experience / lessons learned
4. Incorporate MOV operating experience / lessons learned
5. Add information concerning use of latest Code incorporated by reference in 10 CFR 50.55a instead of plants’ “Code of Record”
6. General update to reflect current guidance (e.g., preconditioning), remove outdated guidance, and correct omissions from or errors in Revision 2 to NUREG-1482.
7. Added information to clarify “Scope of Snubber Program,” while converting from ASME *Boiler and Pressure Vessel Code* (BPV Code), Section XI, to ASME OM Code requirements.
8. Added information to clarify that “compensating strut” is a mechanical snubber and should be included in the plant’s snubber program and required to meet ASME OM Code requirements
9. Added a new flow diagram for use of ASME BPV Code, Section XI, and ASME OM Code for snubbers based on 10 CFR 50.55a requirements
10. Added additional information regarding the use of the Code Cases OMN-13, “Performance-Based Requirements for Extending the Snubber Inservice Visual Examination at LWR Power Plants,” to extend the snubbers inservice visual examination interval up to 10 years.
11. Added additional information regarding the use of the Code Case OMN-15, “Performance-Based Requirements for Extending the Snubber Inservice Operational Readiness Testing Interval at LWR Power Plants,” to extend the snubbers inservice functional testing interval up to 10 years.

12. Included guidance regarding Fleet vs. Plant Snubber Programs.
13. Added information regarding importance of lubricant (grease) in mechanical snubber for Service Life Monitoring Program.
14. Added new Appendix B to NUREG-1482 to provide testing and surveillance guidance for pumps, valves, and snubbers in 10 CFR 50.69 programs.
15. Ensure that reference documents are available on the NRC Public website (www.nrc.gov) for easy access to users.

Discussion

The format of the NUREG-1482, Revision 3, is the same as the previous revision and a typical IST program plan (i.e., Development and Implementation, General Guidance, Valves, Pumps, Technical Specifications, Code Non-Compliance, and Risk-Informed Inservice Testing). NUREG-1482, Appendix A contains inservice examination, testing and service life monitoring (SLM) of dynamic restrains (snubbers). NUREG-1482, Appendix B, "Guidance for Treatment of Pumps, Valves, and Dynamic Restraints (Snubbers) during Implementation of 10 CFR 50.69," provides IST guidance for nuclear power plant licensees implementing 10 CFR 50.69. Throughout the General Guidance, Valves, and Pumps sections of NUREG-1482, IST requirements for which licensees have requested relief or proposed alternatives are discussed, and guidance is provided on the type of information that should typically be included. They also discuss Code and regulatory issues and provide recommendations and guidance as needed. The discussions of issues and recommendations are not intended to impose additional requirements beyond that required by the Code or the regulations and, as such, do not represent backfits. Rather, these discussions are intended to clarify existing requirements of the Code or the regulations, and may provide recommendations to ensure that Code and other regulatory requirements continue to be met.

Section 1 of NUREG-1482 provides the regulatory basis, regulatory history of NRC staff guidance on IST requirements, and a synopsis of this report.

10 CFR 50.55a defines the requirements for applying industry codes and standards to boiling water reactor (BWR) and pressurized water reactor (PWR) nuclear power facilities. Each of these facilities is subject to the conditions in paragraphs (b), (f), and (g) of 10 CFR 50.55a, as they relate to ISI and IST programs.

The ASME OM Code is a national, voluntary consensus standard. The NRC approves or mandates the use of editions and addenda to the codes in 10 CFR 50.55a through the rulemaking process of "incorporation by reference." Once the ASME OM Code edition or addenda is incorporated by reference into the NRC's regulations, each provision of the code that 10 CFR 50.55a incorporates by reference constitutes a legally binding NRC requirement imposed by rule.

One June 3, 2020, the NRC staff revised the NRC regulations in 10 CFR 50.55a(a) to incorporate by reference the 2015 through 2017 Edition of the ASME OM Code. Subsection ISTA provides general IST requirements. Subsections ISTB, ISTC, and ISTD provide IST requirements for pumps, valves, and dynamic restraints, respectively. Subsection ISTE describes an acceptable Risk-Informed IST alternative. Subsection ISTF provides IST requirements for pumps in post-2000 nuclear power plants. Based on those requirements, nuclear power plant licensees must establish IST programs, specify the components included in the program as well as the test methods and frequencies for those components, and implement the program in accordance with the OM Code.

Where a test requirement of the OM Code is determined to be impractical for a facility, the NRC regulations in 10 CFR 50.55a(f)(5)(iii) allow the licensee to submit a request for relief from the given requirement, along with information to support the determination. Relief requests generally detail the reasons for deviating from the Code requirements and propose alternative testing methods or frequencies. Under 10 CFR 50.55a(f)(6)(i), the Commission is authorized to evaluate licensees' relief requests, and may grant the requested relief or impose alternative requirements, considering the burden that the licensee might incur if the Code requirements were enforced for the given facility.

10 CFR 50.55a(f)(5)(iv) and 10 CFR 50.55a(g)(5)(iv) require that where a pump or valve or snubber test requirement by the Code is determined to be impractical and is not included in the IST program, a relief request must be submitted for NRC review and approval not later than 12 months after the expiration of the initial 120-month interval of operation from the start of the facility commercial operation. The licensee must re-submit the relief request for each subsequent 120-month interval of operation during which the test is determined to be impractical.

Pursuant to 10 CFR 50.55a(z)(1) and (2), the Commission may authorize a nuclear power plant licensee to implement an alternative to the Code requirements. In such case, the alternative must ensure an acceptable level of quality and safety, or demonstrate that the Code requirement presents a hardship without a compensating increase in the level of quality and safety.

Section 2 of NUREG-1482 discusses the development and implementation of an IST program. It describes compliance considerations (including ASME OM Code Case applicability), discusses the scope of an IST program, and provides guidance for presenting information in IST programs, including cold shutdown justifications, refueling outage justifications, and relief requests. The section includes a sample list of plant systems for BWRs and PWRs that typically (but not necessarily) contain Code pumps or valves that perform a safety function. The section also includes information needed for licensees to establish the tests and test frequencies for pumps and valves in an IST program.

The NRC staff developed RG 1.192, "Operation and Maintenance Code Case Acceptability ASME OM Code," to identify ASME OM Code Cases that are acceptable for use as alternatives to the ASME OM Code requirements with conditions, as applicable. The NRC staff also developed RG 1.193, "ASME Code Cases not Approved for Use." Where an ASME OM Code Case is accepted in a specific revision to RG 1.192 that has been incorporated by reference in 10 CFR 50.55a, a licensee may implement the Code Case listed in RG 1.192 without obtaining further NRC review, if the Code Cases are used in their entirety, with any supplemental conditions specified in the regulatory guide.

In June 2004, the Nuclear Energy Institute (NEI) issued a white paper titled "Standard Format for Requests from Commercial Reactor Licensees Pursuant to 10 CFR 50.55a, Revision 1." The white paper provides useful guidance in determining the appropriate regulatory requirement under which a "relief request" is submitted to the NRC for approval as well as the appropriate format and content to use in the request. The term "relief request" is used loosely in the NEI white paper to denote the various types of submittals to the NRC allowed by 10 CFR 50.55a including alternatives to the regulation [10 CFR 50.55a(z)], impractical relief requests [10 CFR 50.55a(f)(5)(iii)], and requests to use later Code Editions and Addenda [10 CFR 50.55a(f)(4)(iv)]. The NEI white paper has been reviewed by NRC staff, and the staff generally agrees with the format and content in the white paper and encourages its use, provided the request terminology is used properly.

Occasionally, the NRC receives IST program submittals or partial submittals that lack the start and end dates of the 120-month IST interval or the specific Code Edition and Addenda in use. Some licensees, when developing their IST programs, were not aware that the regulations are issued or updated throughout the year through issuance of Federal Register notices. The *Code of Federal Regulations* is a codification of the general and permanent rules published in the Federal Register, and is kept up to date by the individual issues of the *Code of Federal Regulations* to determine the appropriate Code Edition and Addenda as required in 10 CFR 50.55a(a) rather than the effective date of the rule as noted in the Federal Register notice. Consequently, licensees must use latest version of the 10 CFR 50.55a from the www.ecfr.gov.

Section 3 of the NUREG-1482 provides guidance and NRC recommendations for several general aspects of IST. The significant clarification and guidance in this section fall into three categories: (1) inservice test intervals/frequencies, (2) testing at power/on-line testing/entry in limiting conditions for operation (LCOs), and (3) preconditioning. With regard to test intervals, the NRC may approve relief for extending a test interval for extenuating circumstances in which (1) compliance would result in hardship or unusual difficulty without a compensating increase in the level of quality and safety, or (2) the system design makes compliance impractical. Impractical conditions justifying test deferrals are those that could result in an unnecessary plant shutdown, cause unnecessary challenges to safety systems, place undue stress on components, cause unnecessary cycling of equipment, or unnecessarily reduce the life expectancy of the plant systems and components. Any requested relief would typically include a technical justification for the deferment. Test interval deferrals and exercise frequencies typically have been applied to requests to perform IST cold shutdowns or refueling outages. Unless accompanied by other acceptable rationale, the necessity to enter into an LCO to perform IST would not be sufficient to justify deferring testing until a cold shutdown or refueling outage. Guidance on issues regarding the applicability of LCO and surveillance requirements has been previously issued by the NRC in GL 87-09. If a licensee chooses to defer testing from quarterly to cold shutdown, or to refueling outages, other justification must be included in addition to entry into an LCO. If the deferral is not justified by additional basis, the licensee must perform tests quarterly, or during cold shutdown (as justified), with entry into the LCO for IST to be completed within the out-of-service time allowed by TS.

Preconditioning of structures, systems, and components (SSCs) continues to be an issue of discussion between licensees and NRC staff. In Information Notice (IN) 97-16, “Preconditioning of Plant Structures, Systems, and Components Before ASME Code Inservice Testing or Technical Specification Surveillance Testing,” the NRC staff discussed the longstanding concern regarding unacceptable preconditioning of plant SSCs before testing. The staff noted that experience has demonstrated that some testing cannot be performed without disturbing or altering the equipment. The staff also indicated that any such disturbance or alteration would be expected to be limited to the minimum necessary to perform the test and to prevent damage to the equipment. The staff alerted licensees that, in certain cases, the safety benefit of some preconditioning activities might outweigh the benefits of testing in the as-found condition. NRC Inspection Procedure IP 71111, Attachment 22, “Surveillance Testing,” dated January 1, 2020, provides updated guidance on preconditioning with respect to surveillance testing.

Where the ASME OM Code typically does not provide specific provisions related to as-found testing of a pump or valve in the IST program, the staff considers acceptable preconditioning to include such activities as (1) periodic venting of pumps which is not routinely scheduled directly prior to testing but may occasionally be performed before testing; (2) pump venting directly prior to testing provided the venting operation has proper controls with a technical evaluation to establish that the amount of gas vented would not adversely affect pump operation; (3) occasional lubrication of a valve stem prior to testing of the valve where stem lubrication is not typically performed prior to testing; and (4) unavoidable movement due to the set-up and connection of test equipment. In each instance of acceptable preconditioning, the licensee is expected to have a documented evaluation of the preconditioning activity and justification for continued confidence in the IST program to assess the operational readiness of the pump or valve. Unacceptable preconditioning of pumps and valves in the IST program includes such activities as (1) routine lubrication of a valve stem prior to testing the valve; (2) operation of a pump or valve shortly before a test if such operation could be avoided through plant procedures with personnel and plant safety maintained; and (3) venting a pump immediately prior to testing without proper controls and scheduling. Further clarification and guidance is provided in NUREG 1482, Section 3.5.

Section 4 of the NUREG-1482 provides guidance and recommendations on valve issues. Revision 3 addresses check valves, power-operated valves (e.g., motor-, air-, and hydraulically-operated valves), safety and relief valves, and miscellaneous valves such as manual valves and pressure isolation valves. NUREG-1482, Section 4, also provides guidance on instrumentation and instrument accuracy.

As operating experience with the recent Code changes grows, issues regarding valve IST will continue to emerge and be resolved. The NRC staff intends to continue to update and improve its IST guidance through participation in standards development organizations and technical groups, issuance of generic communications such as information notices, regulatory issue summaries, and generic letters, as well as through regular updates of NRC guidance documents (e.g., NUREG-1482) as the need arises.

Section 5 of the NUREG-1482 provides guidance and recommendations on pump issues. Revision 3 addresses the use of reference curves, evaluation of pump vibration, Group A and Group B pump tests and comprehensive pump test (CPT), minimum flow lines, instrument and equipment accuracy, pump drivers as well as other issues of interest in the IST of pumps.

A CPT may be substituted for a Group A test or Group B test. A Group A test may be substituted for a Group B test. A preservice test may be substituted for any inservice test. All pumps would receive a preservice or baseline test followed by quarterly (periodic) tests. The Code allows the less rigorous pump testing to be performed for certain pumps on a quarterly frequency while requiring a pump test to be performed with more accurate flow instrumentation every 2 years at ±20 percent of pump design flow. The intent is to be able to routinely monitor for degradation using the quarterly test and to verify design capability using the CPT.

The NRC staff may accept the use of a lower flow (reference values less than ±20% of the design flow), as required by Subsection ISTB for the comprehensive test, if the licensee demonstrates in a relief request the impracticality of establishing a reference value within ±20% of the design flow for the CPT. The proposed alternative methods to detect hydraulic degradation and trend degradation must provide reasonable assurance of the pump’s operational readiness. The NRC reviews these relief requests on a case-by-case basis.

Pump drivers are outside of the scope of the ASME OM Code with the exception of vibration testing for vertical line shaft pumps where the driver is an integral part of the pump. Most of the pumps are driven by electric motors, which are connected via coupling shafts. Motor vibration due to coupling misalignment might not be realized or measured at the pump. Small changes in vibration of a motor can have significant effects on the pump operation and affect the operational readiness of the pump. While excluded from the ASME OM Code, the health of pump drivers should be included in a licensee's overall plan for the assessment of its pumping systems.

Institute of Electrical and Electronics Engineers (IEEE) Standard 741-2007, "IEEE Standard Criteria for the Protection of Class 1E Power Systems and Equipment in Nuclear Power Generating Stations," briefly addresses the vibration issue, and refers to IEEE C37.96-2000, "IEEE Guide for AC Motors Protection," for motors. IEEE 741-2007 includes testing and surveillance requirements, and lists several standards in the reference section for testing. IEEE C37.96-2000 extensively addresses the vibration issue on electric motors because of its significant impact on internal parts such as bearings, lubricants, and protective devices.

Subsection ISTF, "Inservice Testing of Pumps in Water-Cooled Reactor Nuclear Power Plants – Post-2000 Plants," in the OM Code provides IST requirements for pumps in new reactors. The Subsection ISTF provisions for pumps in new reactors specify an inservice test on a quarterly frequency. The NRC has incorporated by reference Subsection ISTF in 10 CFR 50.55a with a condition to ensure that the provisions of Appendix V are implemented.

Section 6 of the NUREG-1482 discusses revised standard TSs. The purpose of a pump or valve inservice test is to assess the operational readiness of the component. Inservice tests are designed to detect component degradation by assessing component performance in relation to operating characteristics when the component was known to be operating acceptably. Thus, the data or information obtained during these tests provide insight into the ability of a component to perform its safety-related function under design-basis conditions until the next test. In contrast, TS surveillance requirements typically assess system capability; e.g., the ability of a system or component (e.g., pump) to deliver the flow rate assumed in an accident analysis at the time of the test. The revised standard TS reflect the fact that licensees are required by 10 CFR 50.55a to establish and implement an IST program. Section 6 further discusses this topic and reaffirms previous guidance with respect to Code versus TS test frequencies.

Section 7 of the NUREG-1482 discusses the process for licensees to follow when a Code nonconformance is found. This section is being updated to clarify the relationship between Code and TS noncompliance. The guidance in this section is not being significantly changed with the exception of deleting a discussion on Design Bases reviews and including further clarifying guidance on starting points for time periods in TS action statements.

Section 8 of the NUREG-1482 discusses the development of a risk-informed IST program. RG 1.175, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Inservice Testing," describes an acceptable alternative approach for applying risk insights from probabilistic risk assessment (PRA), in conjunction with established traditional engineering information, to improve a nuclear power plant's IST program. The approach described in RG 1.175 addresses the high-level safety principles specified in RG 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," and attempts to strike a balance between defining an acceptable process for developing risk-informed IST programs without being overly prescriptive. As discussed in RG 1.175, licensees proposing to implement a risk-informed IST program are required to submit a request to implement an alternative to the OM Code in accordance with 10 CFR 50.55a(z).

Section 8 discusses several factors to be taken into consideration when preparing (and in evaluating) such relief requests to ensure that the proposed alternative provides an acceptable level of quality and safety. The list is not all inclusive but does provide a useful starting point. Over the past several years, the ASME has developed a series of risk-informed Code Cases related to testing of pumps and valves. When using the ASME's risk-informed Code Cases, the testing and performance monitoring of individual components must be performed as specified in the risk informed component Code Cases (e.g., OMN-1, OMN-4, OMN-7, OMN-11, and OMN-12) as modified by any conditions specified in RG 1.192. The use of the Code Cases is discussed in both Section 2 and Section 8 of NUREG-1482.

The OM Code, Subsection ISTE, "Risk-Informed Inservice Testing of Components in Water-Cooled Reactor Nuclear Power Plants," addresses overall aspects of risk-informed IST programs. As indicated in 10 CFR 50.55a(b)(3)(viii), licensees may not implement the risk-informed approach for inservice testing of pumps and valves specified in Subsection ISTE in the 2009 Edition through the 2017 Edition of the OM Code, without first obtaining NRC authorization. The NRC staff is reviewing Subsection ISTE in the 2020 Edition of the OM Code as part of the incorporation by reference of that edition of the OM Code in 10 CFR 50.55a with any applicable conditions.

Appendix A of the NUREG-1482 provides information related to snubber inservice examination, testing and service life monitoring regulation, scope and its implementation at various nuclear plants similar to details provided to the inservice testing of pumps and valves provided above, and added additional information and topics related to snubbers (Items 7 through 15) as provided in the Introduction.

A newly added Appendix B of the NUREG-1482 provides information related to guidance for treatment of pumps, valves, and dynamic restraints (snubbers) during implementation of 10 CFR 50.69.

Conclusion

The NRC intends to continue to revise its guidance as experience is gained and lessons are learned through participation in the ASME OM Code committees and technical organizations, and through regular updates of NRC published guidance as the need arises. Revision 3 to NUREG-1482 is an update incorporating the most recent regulatory changes including the incorporation by reference of the ASME OM Code, 2015 Edition through 2017 Edition. To the extent practical, it reflects the applicable section, subsection, or paragraph of the appropriate documents (10 CFR Part 50, ASME OM Code, and regulatory guides). Revision 2 is still valid and may continue to be used by those licensees who have not updated their IST program to the 2012 OM Code (or later). The requirement for licensees to periodically update their IST programs to later ASME OM Code Editions and Addenda is governed by 10 CFR 50.55a. In the future, NUREG-1482 will be updated on an 'as-needed" basis, as Code requirements evolve or other regulatory changes in direction affect the guidance therein.

The guidance provided in many sections herein may be used for requesting relief from or alternatives to ASME OM Code requirements. However, licensees may also request relief or authorization of an alternative that is not in conformance with the guidance. In evaluating such requested relief or alternatives, the NRC uses the guidelines and recommendations of NUREG-1482, where applicable. The NRC may reference a recommendation from NUREG-1482 in safety evaluations, and grant relief or authorize an alternative if the licensee has addressed all of the aspects included in the applicable section.

The guidelines and recommendation provided in NUREG-1482 and its Appendix A and Appendix B do not supersede the regulatory requirements specified in 10 CFR 50.55a. Further, NUREG-1482 does not authorize the use of alternatives to, or grant relief from, the ASME OM Code requirements for inservice testing of pumps and valves, or inservice examination and testing of dynamic restraints (snubbers), incorporated by reference in 10 CFR 50.55a.

Acknowledgements

I would like to thank my senior colleagues Thomas Scarbrough and Robert Wolfgang for reviewing this paper and providing valuable input.

References

1. American Society of Mechanical Engineers/American National Standards Institute (ASME/ANSI), Code for Operation and Maintenance of Nuclear Power Plants, New York.

2. U. S. Code of Federal Regulations, Title 10, “Energy,” Chapter 1, Part 50, “Domestic Licensing of Production and Utilization Facilities.”

3. NUREG-1482, “Guidelines for Inservice Testing at Nuclear Power Plants,” Revision 3, July 2020, ADAMS Accession No. ML20202A473.

4. Nuclear Energy Institute (NEI), White Paper, “Standard Format for Requests from Commercial Reactor Licensees Pursuant to 10 CFR 50.55a, Revision 1,” June 2004, ADAMS Accession No. ML070100400.

ASME OM Code Cases

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Abstract

The American Society of Mechanical Engineers (ASME) *Operation and Maintenance of Nuclear Power Plants*, Division 1, OM Code: Section IST (OM Code) utilizes a process that allows new innovation to be quickly and retroactively applied via documents known as Code Cases. Code Cases are frequently initiated via the ASME OM Code Inquiry process, which typically asks for an alternative to existing requirements.

The number of ASME OM Code Cases have been relatively few compared to other ASME Codes and Standards as this committee is relatively new and smaller in scope when compared to the other Codes and Standards. In the past, Code Cases were published as companion documents with new ASME OM Code Editions or Addenda. As a matter of a policy change, ASME will no longer be including these Code Cases as companion documents.

For a limited time, ASME is providing Code Cases not previously published with past ASME OM Code Editions or Addenda free of charge as a download from the ASME CSTools website located on the ASME OM Standards Committee web page. A new section in the ASME OM Code will include a comprehensive list of the ASME OM Code Cases and the Editions and Addenda to which they apply.

This paper will describe the ASME policy change for OM Code Cases. The ASME OM Code Cases will be described in general to give the potential end user a foundation of understanding regarding their intended purpose and usage limitation. An overview of the new ASME OM Code Case Index, which will be published as part of the ASME OM Code, will be provided to convey the details of this new section.

The regulatory process regarding Code Cases will be addressed to clarify the means by which they may be implemented for components under the Inservice Testing regulatory requirements under Section 50.55a, “Codes and Standards,” in Part 50, “Domestic Licensing of Production and Utilization Facilities,” to Title 10, “Energy,” of the *Code of Federal Regulations* (10 CFR 50.55a). Code Cases specifically approved for use by either the 10 CFR 50.55a regulation, or its companion Regulatory Guide 1.192, “Operation and Maintenance Code Case Acceptability, ASME Code,” after its incorporation by reference in 10 CFR 50.55a, will be discussed. The discussion will include an examination of any regulatory limitations placed on these documents for implementation.

The final section of the paper will discuss those Code Cases not generally approved by regulatory documents at the present time. The process by which the U.S. Nuclear Regulatory Commission (NRC) reviews and approves these documents will be examined to ensure a basic understanding of how the process functions. The paper discusses the means available to obtain approval from the NRC for Code Case use by an Inservice Testing Program before they are generically approved for industry use.

1.0 Introduction

We use many acronyms in the nuclear power industry. After working at a power plant for about a year, each person's vocabulary tends to expand to encompass the many acronyms for everyday use with co-workers. The American Society of Mechanical Engineers (ASME) acronym is one of the most recognized in the world. Most people who work in the nuclear power industry know what the ASME acronym means. The OM after ASME is an acronym for the "Operation and Maintenance of Nuclear Power Plants." The ASME Operation and Maintenance of Nuclear Power Plants Codes and Standards Committee is a body of engineers who are highly regarded in their nuclear power industry field of expertise. This presentation is about a special kind of document this committee creates and utilizes, which is known as a "Code Case."

2.0 ASME Codes and Standards Documents

The ASME OM Codes and Standards Committee writes documents that convey technical requirements for nuclear power plants. Some of these documents convey they are Codes while others refer to themselves as Standards in the title. What is the difference between documents described as a Standard compared to a document described as a Code? The difference is the law, which compels the use of a Code verses a technical document that is not compelled by law. Keep in mind that Standards may be something that can be used to meet legal requirements, but the law may not stipulate the document by name or even if it does, it would not require its use like the law does for a Code.

The ASME OM Codes and Standards Committee was originally the ASME OM Standards Committee. This changed when the Nuclear Regulatory Authority, who regulates the law in part by using the regulation 10 CFR 50.55a, changed the requirements for testing safety-related dynamic restraints, pumps, and valves to reference the ASME OM Code that collectively was created from a series of OM Standards. The present Charter of the ASME OM Codes and Standards Committee describes the purpose of this committee as follows: "To develop, review, maintain, and coordinate codes, standards, and guides applicable to the safe and reliable operation and maintenance of nuclear power plants." It was immediately recognized as a Code body that a convenient means was needed to avoid stifling innovations in both technology and processes.

3.0 ASME Code Cases

The ASME OM Code utilizes a process that allows new innovation to be quickly and retroactively applied via documents known as Code Cases. Code Cases are frequently initiated via the ASME OM Code Inquiry process.

ASME OM Code Case Basics

ASME OM Code Cases most typically ask a question regarding an alternative means or methods to accomplish a requirement to verify the operational readiness of pumps, valves, overpressure protection devices, or snubbers within the scope of ISTA-1100. The use of a Code Case may convey an appropriate means to gain experience to overcome uncertainty with the use of new technology or methods.

Code Cases are intended to be temporary. While this is not always how they are used by ASME at large, the ASME OM Code Committee at this time intends to incorporate all Code Cases into the ASME OM Code. As with other ASME Code Committees, there may be situations where Code Cases are not incorporated in the Code. Engineering judgement is applied by committee members to determine when Code Case requirements have sufficient confidence from implementing experience.

Code Case Format

ASME OM Code Cases may be requested by providing a written “Statement of Need” with “Background Information.” Anyone who can provide a “statement of need” can initiate the development of a Code Case. The ASME OM Committee defines these terms under the Code Revisions and Additions section as follows:

- Statement of Need. Provide a brief explanation of the need for the revision(s) or addition(s).
- Background Information. Provide background information to support the revision(s) or addition(s), including any data or changes in technology that form the basis for the request that will allow the Committee to adequately evaluate the proposed revision(s) or addition(s). Sketches, tables, figures, and graphs should be submitted as appropriate. When applicable, identify any pertinent paragraph in the Code that would be affected by the revision(s) or addition(s) and paragraphs in the Code that reference the paragraphs that are to be revised or added.

The initial Code Case is to be written in a manner similar to the Code Revision and Addition process with a Question and Reply format. The proposal should identify the Code Section and Division to which the Code Case is intended to apply. Refer to the front of the ASME OM Code for the section titled “Correspondence with the OM Committee” for details on how to request Code Cases.

ASME Code Case Publication Policy Change

The number of ASME OM Code Cases have been relatively few compared to other ASME Codes and Standards. In the past, Code Cases were published as companion documents with new ASME OM Code Editions or Addenda. As a matter of a policy change, ASME will no longer be including these Code Cases as companion documents.

For a limited time, ASME is providing Code Cases not previously published with past ASME OM Code Editions or Addenda free of charge as a download from the ASME CSTools website located on the ASME OM Standards Committee web page. A new section in the ASME OM Code includes a comprehensive list of the ASME OM Code Cases and the Editions and Addenda to which they apply. This new section of the ASME OM Code is included with the front matter with the title “Applicability Index for ASME OM Cases.”

Regulatory Approval Required

All Code Cases must be approved by the regulatory authority that compels the use of the ASME OM Code prior to use. In the USA, certain Code Cases may be approved for use by the Inservice Testing regulatory requirements under 10 CFR 50.55a. The other regulatory document associated with the use of ASME OM Code Cases in the USA is Regulatory Guide 1.192, “Operation and Maintenance Code Case Acceptability, ASME Code.” Code Cases specifically approved for use by the NRC may include limitations or conditions. This is the case for the ASME OM Code Committee’s first Code Case which is known as ASME Code Case OMN-1. While the NRC did approve this in the past via 10 CFR 50.55a, there were a number of conditions that also had to be met or satisfied with its use.

Code Cases Not Approved by the Regulatory Authority

Regulatory Guide 1.193, “ASME Code Cases Not Approved for Use,” describes a number of Code Cases that the NRC staff has considered for generic approval and use. For various reasons, the NRC staff determined the Code Cases referenced contained within this document were not acceptable for use on a generic basis. It should be noted that this document includes a discussion for the basis of the decision, which may be used to apply for the use of the Code Case via the regulation 10 CFR 50.55a(z), which permits the use of alternatives to the Code requirements referenced in 10 CFR 50.55a.

At the time of this writing, the ASME OM Code Committee had only two Code Cases in Regulatory Guide 1.193 that are deemed unacceptable for generic use. One of these is Code Case OMN-10, Rev. 0, “Requirements for Safety Significance Categorization of Snubbers Using Risk Insights and Testing Strategies for Inservice Testing of LWR Power Plants,” July 1, 2000. The description listed in Table 3 as the basis is provided here as an example.

> The method used for categorizing snubbers could result in certain snubbers being inappropriately categorized as having low safety significance. These snubbers would not be adequately tested or inspected to provide assurance of their operational readiness. In addition, unexpected extensive degradation in feedwater piping has occurred which would necessitate a more rigorous approach to snubber categorization than presently contained in this Code Case.

If a user wants to use Code Case OMN-10, this concern would have to be addressed to the satisfaction of the NRC in either the initial 10 CFR 50.55a(z) submittal or a subsequent Request for Additional Information (RAI) that may seek additional technical or implementation details.

ASME OM Code Cases not described as approved for use by regulatory documents in the USA must have regulatory approval via 10 CFR 50.55a(z) before they are used as the sole means to implement ASME Code Requirements. The only way ASME OM Code Cases may be used without this regulatory approval is when the existing ASME Code requirements are still satisfied. This approach is typically only used when research is being conducted to support an intention to obtain regulatory approval for ASME OM Code Case use.

Code Cases Not Yet Reviewed by NRC

New Code Cases have been taking many years to be reviewed and approved for generic use by the NRC. Because these documents frequently convey immediate needs for Licensees, a request may be submitted to the NRC for the purposes of obtaining permission for use. Alternative methodologies to specific requirements in the ASME OM Code may be requested via the requirements of 10 CFR 50.55a(z) when they can be demonstrated to maintain an equivalent level of safety and quality.

4.0 Conclusion

Code Cases provide a convenient means to incorporate innovations in technology and processes. Anyone may request an OM Code Case using the descriptions contained in the front matter of the latest edition of the ASME OM Code. Regulatory approval is required prior to using a Code Case as an alternative to the requirements within the ASME OM Code. In the USA, OM Code Cases are approved for use in the regulation 10 CFR 50.55a or by Regulatory Guide 1.192, as incorporated by reference in 10 CFR 50.55a. Requests to use OM Code Cases not approved by either of these documents may be requested via the regulation 10 CFR 50.55a(z), which permits the use of alternatives to the Code requirements referenced in 10 CFR 50.55a, where justified to the NRC.

5.0 References

1. *U.S. Code of Federal Regulations,* Title 10, “Energy,” Part 50, “Domestic Licensing of Production and Utilization Facilities” (Available on NRC or U.S. Government Publishing Office Web site)
2. United States Nuclear Regulatory Commission (U.S. NRC), Regulatory Guide (RG) 1.192, “Operation and Maintenance Code Case Acceptability, ASME OM Code” (Available on NRC Web site)
3. USNRC, RG 1.193, “ASME Code Cases Not Approved For Use” (Available on NRC Web site)
4. ASME OM Code, 2020 Edition, *Operation and Maintenance of Nuclear Power Plants* (Available through ASME Web site)

Augmented IST Program Requirements – Scope and Testing*

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* This paper was prepared by staff of the Tennessee Valley Authority (TVA). The information presented herein is based on the personal opinion of the author and does not represent an agreed-upon TVA staff position.

Abstract

The purpose of this presentation is to raise awareness on the requirements in Section 50.55a, "Codes and standards," in Title 10, "Energy," of the *Code of Federal Regulations* (10 CFR 50.55a), paragraph (f)(4), for development and implementation of an Augmented Inservice Testing (IST) Program. This presentation will highlight the changes in 10 CFR 50.55a rulemaking that changed the scope of the regulatory required IST Program to include all safety-related components regardless of their site-specific American Society of Mechanical Engineers (ASME) *Boiler and Pressure Vessel Code* (BPV Code) Class equivalent classification. This presentation will also describe the available options to address those components classified as ASME BPV Code Class 1, 2, or 3 equivalent versus those that are not classified as ASME BPV Code equivalent which also meet the scope statement of ASME *Operation and Maintenance of Nuclear Power Plants*, Division 1, OM Code: Section IST (OM Code), Subsection ISTA, "General Requirements," paragraph ISTA-1100, "Scope."

I. Introduction

Regulatory requirements for licensees to develop, implement, and periodically update a formal program for testing of pumps, valves, pressure relief devices, and dynamic restraints has been in place since 1977. The first regulatory mention of an Augmented Inservice Testing (AIST) Program appeared in 10 CFR 50.55a(f)(6)(ii) in the year 2000. However, the actual scope of Inservice Testing (IST) Programs were essentially unchanged until 2017 when new regulatory requirements were imposed. This paper aims to provide clarification of the current regulatory requirements for the scope of IST and AIST Programs. In order to do this, it is important to provide a brief history of these regulatory requirements and evolution of the ASME Code.

II. History of Scope Requirements

Initial Requirement for Inservice Testing (IST) Program

In 1977, 10 CFR 50.55a(g) required development, implementation of an Inservice Inspection (ISI) Program for ASME *Boiler and Pressure Vessel Code* (BPV Code) Class 1, Class 2, and Class 3 that complies with the ASME BPV Code, Section XI, 1974 Edition through 1975 Addenda as referenced in 10 CFR 50.55a(b)

ASME BPV Code, Section XI, 1974 Edition, is the first edition that included Subsection IWP, “Inservice Testing of Pumps in Nuclear Power Plants,” and Subsection IWV, “Inservice Testing of Valves in Nuclear Power Plants.” In the beginning and for many years thereafter, the IST Program was a subset of the ASME BPV Code, Section XI, ISI Program.

Applicable IST Program Scope

Governing Regulatory: 10 CFR 50.55a(g) – ASME BPV Code Class 1, 2, and 3

ASME BPV Code: Subsection IWP-1100 and IWV-1100 – ASME BPV Code Class 1, 2, and 3

Transition from ASME Section XI to ASME Operation and Maintenance (OM)

In 1998, 10 CFR 50.55a(g) required development, implementation of an Inservice Inspection (ISI) Program for ASME BPV Code Class 1, Class 2, and Class 3 that complies with the ASME BPV Code, Section XI, 1988 Addenda through 1989 Edition, as referenced in 10 CFR 50.55a(b).

The 1988 Addenda of Section XI revised Subsection IWP and Subsection IWV to remove the previous requirements and simply point to the 1988 Addenda of ASME/ANSI *Operation and Maintenance of Nuclear Power Plants* (OM) Part 6 and Part 10, respectively. It is also worth noting that the 1988 Addenda of ASME BPV Code, Section XI, also revised Subsection IWF to include pointers to the 1988 Addenda of OM Part 4 for testing of the dynamic restraint portion of component supports.

From this point forward, testing of pump, valves, pressure relief devices, and dynamic restraints transitioned out of ASME BPV Code, Section XI, and into the ASME OM Code as follows:

- OM Part 4, Examination and Performance Testing of Nuclear Power Plant Dynamic Restraints (Snubbers)
- OM Part 6, Inservice Testing of Pumps in Light-Water Reactor Power Plants
- OM Part 10, Inservice Testing of Valves in Light-Water Reactor Power Plants

Applicable IST Program Scope

Governing Regulatory: 10 CFR 50.55a(g) – ASME BPV Code Class 1, 2, and 3

ASME OM Code: Part 4 – ASME BPV Code Class 1, 2, 3, and MC

ASME OM Code: Part 6 and Part 10 – Based on component function and NOT limited to ASME BPV Code Class.

Part 6 Scope Statement - The pumps covered are those, provided with an emergency power source, which are required in shutting down a reactor to the cold shutdown condition, maintaining the cold shutdown condition, or mitigating the consequences of an accident.

Part 10 Scope Statement - The active or passive valves covered are those which are required to perform a specific function in shutting down a reactor to the cold shutdown condition, in maintaining the cold shutdown condition, or in mitigating the consequences of an accident. The pressure-relief devices covered are those for protecting systems or portions of systems which perform a required function in shutting down a reactor to the cold shutdown condition, in maintaining the cold shutdown condition, or in mitigating the consequences of an accident.

Transition of IST / AIST Program Scope Based on Safety-Related Function vs Code Class

Final rulemaking for 10 CFR 50.55a published in *Federal Register* Vol. 82, No. 136, dated Tuesday, July 18, 2017, which became effective on August 17, 2017, resulted in a significant change in the scope of IST / AIST Programs. Essentially, this change expanded the regulatory required scope of IST / AIST to be based on component function and NOT limited to ASME BPV Code Class 1, 2, or 3 components as specified in the ASME OM Code. This is the first time that the 10 CFR 50.55(f)(4) scope statement and the ASME OM Code scope statements have been in alignment. The specific change to 10 CFR 50.55a(f)(4) is shown below for reference.

Before	After
Throughout the service life of a boiling or pressurized water-cooled nuclear power facility, pumps and valves that are classified as ASME Code Class 1, Class 2, and Class 3 must meet the inservice test requirements (except design and access provisions) set forth in the ASME OM Code and addenda that become effective subsequent to editions and addenda specified in paragraphs (f)(2) and (3) of this section and that are incorporated by reference in paragraph (a)(1)(iv) of this section, to the extent practical within the limitations of design, geometry, and materials of construction of the components.	Throughout the service life of a boiling or pressurized water-cooled nuclear power facility, pumps and valves that are within the scope of the ASME OM Code must meet the inservice test requirements (except design and access provisions) set forth in the ASME OM Code and addenda that become effective subsequent to editions and addenda specified in paragraphs (f)(2) and (3) of this section and that are incorporated by reference in paragraph (a)(1)(iv) of this section, to the extent practical within the limitations of design, geometry, and materials of construction of the components. The inservice test requirements for pumps and valves that are within the scope of the ASME OM Code but are not classified as ASME BPV Code Class 1, Class 2, or Class 3 may be satisfied as an augmented IST program in accordance with paragraph (f)(6)(ii) of this section without requesting relief under paragraph (f)(5) of this section or alternatives under paragraph (z) of this section. This use of an augmented IST program may be acceptable provided the basis for deviations from the ASME OM Code, as incorporated by reference in this section, demonstrates an acceptable level of quality and safety, or that implementing the Code provisions would result in hardship or unusual difficulty without a compensating increase in the level of quality and safety, where documented and available for NRC review.

III. Methods to Ensure Regulatory Compliance

Following the rulemaking effective on August 17, 2017, described above, the scope of IST / AIST Programs is determined by the ASME OM Code. The pertinent portion of the ASME OM Code, Subsection ISTA-1100, “Scope,” is provided, in part, below.

> ”…These requirements apply to
>
> (a) pumps and valves that are required to perform a specific function in shutting down a reactor to the safe shutdown condition, in maintaining the safe shutdown condition, or in mitigating the consequences of an accident
>
> (b) pressure relief devices that protect systems or portions of systems that perform one or more of the three functions identified in (a)
>
> (c) dynamic restraints (snubbers) used in systems that perform one or more of the three functions identified in (a), or to ensure the integrity of the reactor coolant pressure boundary”

The OM scope statement is essentially the same as the 10 CFR 50.2 definition of safety-related structures, systems and components with the exception that the ASME OM Code doesn’t include language related to integrity of the reactor coolant pressure boundary.

The first step in determining IST Program scope before the 2017 rulemaking was to compile a list of ASME BPV Code Class 1, 2, and 3 components, and then determine which of the components on the code class list met the scope criteria of the ASME OM Code. After the 2017 rulemaking, it is necessary to compile a list of components that meet the scope of the ASME OM Code and then determine their ASME BPV Code Class. Those components that are both: 1) In scope of the ASME OM Code; and 2) ASME BPV Code Class 1, 2, or 3 are required to be in the scope of the IST Program. Components that are in the scope of the ASME OM, Code but are NOT ASME BPV Code Class 1, 2, or 3 may be treated differently. The language of 10 CFR 50.55a(f)(4) provides two options for licensees to address this case. Figure 1 and Figure 2 below illustrates the differences between IST and AIST.

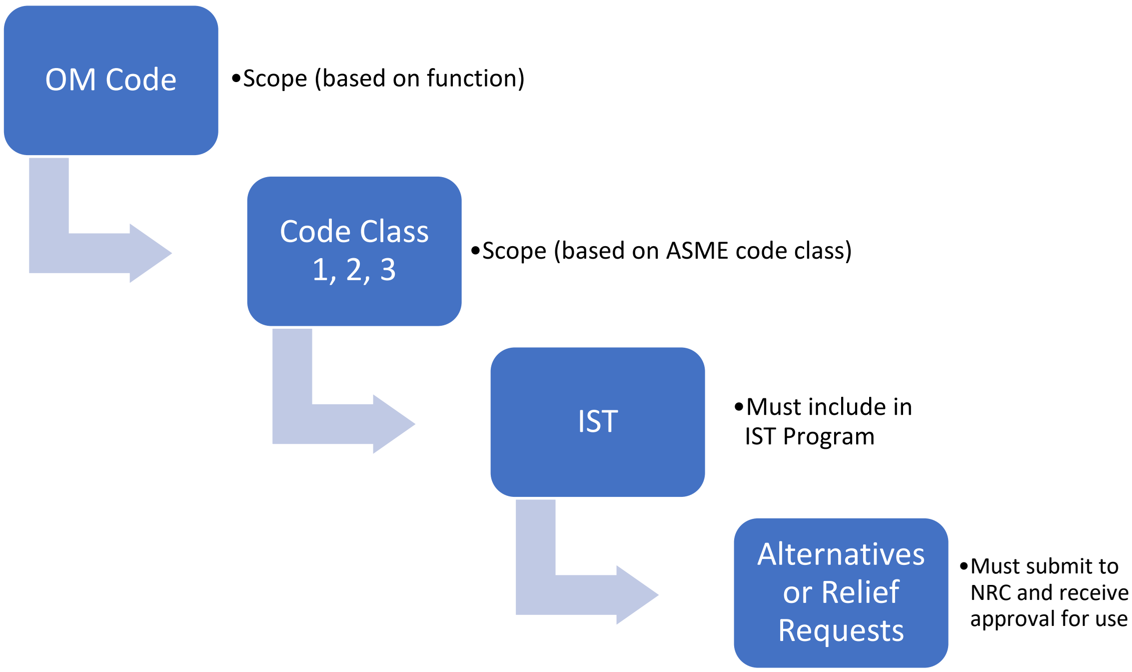

Figure 1: IST Program Scope

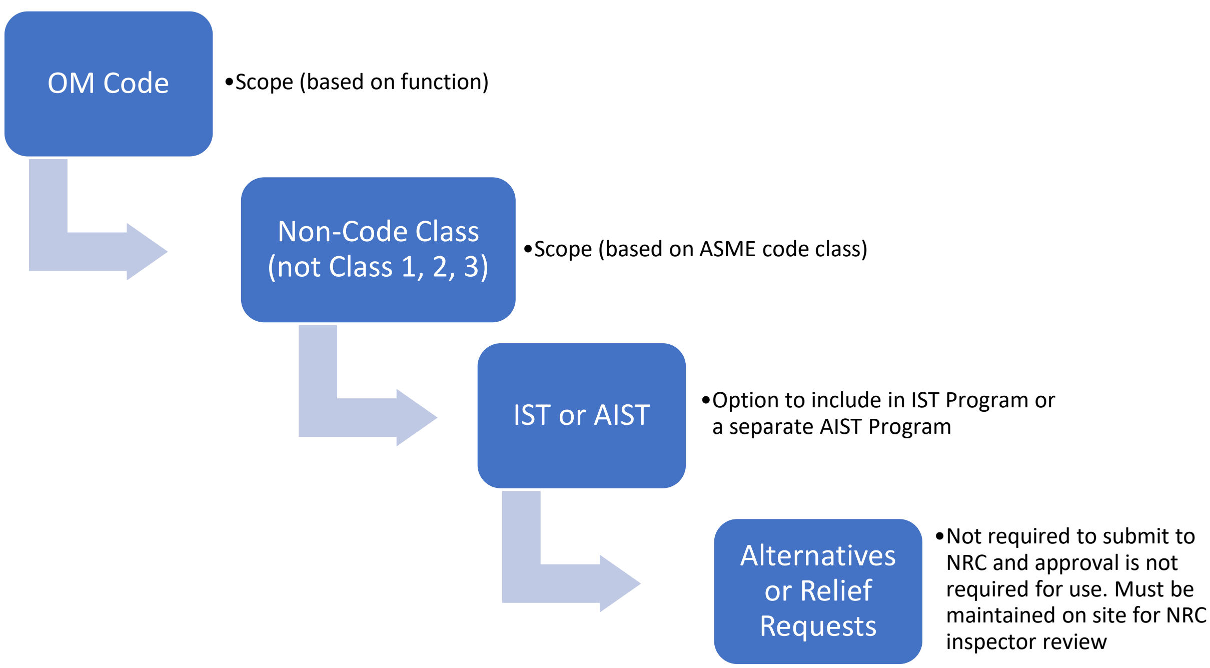

Figure 2: AIST Program Scope

The only real difference between components in scope of the AIST Program and IST Program is with respect to alternative requests and relief requests. Specifically, alternative and relief requests for AIST Program components are not required to be submitted to NRC for review and approval for use. AIST alternative and relief requests should be written to the same level of rigor as if they would be submitted to NRC review and approval. They must be available at the site for review by NRC inspectors as needed.

IV. Conclusion

The 10 CFR 50.55a rulemaking changes effective on August 17, 2017, represent a significant change by placing component function as the primary criteria for scoping into the IST Program. It is the first time that NRC has mandated inclusion of non-Code Class components in the scope of testing in accordance with ASME OM Code (IST Program). In addition, it is the first time NRC has provided guidance for the scope of an AIST Program and the benefits it offers with respect to relaxation of alternative and relief request requirements. Prior to this rulemaking, an AIST Program was discussed in 10 CFR 50.55a(f)(6(ii), but there was no specific requirement or guidance for its use.

The 10 CFR 50.55a rulemaking changes effective on August 17, 2017, have the potential to cause a significant increase in the number of components in the scope of the AIST and IST Programs depending on licensee's plant-specific design.

V. References

1. U.S. *Code of Federal Regulations*, Title 10, "Energy," Part 50, "Domestic Licensing of Production and Utilization Facilities," and Part 50.55a, "Codes and Standards." (Available on NRC or U.S. Government Printing Office (GPO) website.)

2. ASME *Boiler & Pressure Vessel Code*. (Available through ASME website.)

3. ASME *Operation and Maintenance of Nuclear Power Plants*, Division 1, OM Code: Section IST. (Available through ASME website.)

4. *Federal Register*, 82 Fed. Reg. 136, dated July 18, 2017. (Available through the National Archives and Records Administration website).

Pumps

Track Chairs: Thomas Robinson, Nebraska Public Power District, and Thomas Ruggiero, PE, ASME Fellow, OM Standards Committee Member

Pump Performance Requirements, Test Margins, and the Impact of Emergency Diesel Generator Voltage and Frequency Tolerances

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Abstract

Accurate calculation of pump performance margins relative to test acceptance criteria are driven by a variety of requirements and constraints. Inputs including design-basis required performance, acceptance criteria assumptions, test conditions, and field versus vendor data are required. Test margin with respect to safety analysis limits may be more limiting than the American Society of Mechanical Engineers (ASME) *Operation and Maintenance of Nuclear Power Plants*, Division 1, OM Code: Section IST (OM Code) [1] inservice testing (IST) requirements. In response to component design basis inspection (CDBI) and design basis assurance inspection (DBAI) findings of potentially non-conservative equipment performance when operating at the extremes of Emergency Diesel Generator (EDG) Technical Specification (TS) limits of frequency and voltage, Westinghouse and the Pressurized Water Reactor Owners Group (PWROG) developed WCAP-17308-NP-A [2] to provide a simplified approach to incorporate these limits, by treating them as uncertainties, into design basis pump test acceptance criteria. The basic methodology provides a general approach to account for uncertainties by adjusting pump curves and test acceptance criteria. Depending on the magnitude of the EDG and instrument uncertainties, adjusted design basis related test acceptance criteria may challenge the tested performance of the pumps. Margin can be recovered by reducing uncertainties and taking credit for any available margin in the safety analyses.

Nomenclature

ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
ESF	Engineered Safety Features
f_{Nom}	frequency, hertz (Hz)
g	gravitational acceleration, ft/sec^2
NPSH	Net Positive Suction Head, ft
P_D	pump discharge pressure, psig
P_S	pump suction pressure, psig
TAC	Test Acceptance Criteria
TDH	total developed head, ft
U_f	uncertainty in frequency, Hz
U_V	uncertainty in voltage, V
$U_{\Delta H}$	uncertainty in pump developed head measurement, ft
$U_{\Delta H\text{-}Q}$	uncertainty in pump developed head due to flow uncertainty, ft

$U_{\Delta H\text{-}\omega}$ uncertainty in pump developed head due to speed uncertainty, ft
V_D pump discharge velocity, ft/sec
V_S pump suction velocity, ft/sec
V_{Nom} nominal nameplate or supply voltage, V
Z_D pump discharge pressure sensor elevation, ft
Z_S pump suction pressure sensor elevation, ft
DH differential head, feet
DP differential pressure, psid
ρ fluid density, lb/ft^3
ω_{Synch} synchronous speed, rpm
ω_{Nom} nominal, asynchronous speed, rpm

1. Introduction

This paper will discuss and compare pump inservice and Technical Specification requirements and tests, design basis performance, instrumentation and EDG uncertainties and their impact on performance and test acceptance criteria, and differences between measured pump performance and vendor pump performance curves.

NRC Information Notice IN 97-90 [3] alerted nuclear power plant owners of the need to ensure that design requirements are considered in addition to the ASME OM Code requirements when establishing test acceptance criteria to ensure that each safety-related pump achieves its minimum design basis required performance. Notices of violation of 10 CFR Part 50, Appendix B [4], Criterion XI, "Test Control," have been issued when IST limits were found to be non-conservative with respect to the design basis required performance assumed in safety analyses, which are established in accordance with 10 CFR Part 50, Appendix B, Criterion III, "Design Control."

The allowable pump performance typically includes a range of minimum and maximum performance limits that may take the form of head-flow curves or a single parameter such as flow rate. Emergency Core Cooling System (ECCS) performance is typically analyzed using both minimum and maximum pump curves due to the wide range of events included in the plant safety analyses and their consequences, which results in these pumps operating over a wide range of flow rates in response to varying system boundary pressures and reservoir water levels during the course of an event. Other Engineered Safety Feature (ESF) pumps may have safety-related minimum curves while the maximum pump performance is limited solely for pump runout prevention and to ensure adequate net positive suction head available (NPSHA). Pump curves are inputs to hydraulic system analyses to determine delivered flow rates for a wide range of plant conditions. System design dictates system resistance which, in conjunction with the pump performance, sets the delivered flow. Accident and transient analyses determine plant (RCS, containment, steam plant) response using the delivered flow rates to mitigate the consequences of abnormal events. Some accident analyses utilize a combination of minimum and maximum performance limits.

ASME OM Code, Subsection ISTB/ISTF limits assume compliance with specified instrumentation limits and are used to assess operational readiness by comparison to established reference values; however, when assessing pump performance relative to safety analysis assumed performance, actual instrument uncertainties must be taken into account. ASME OM Part 28 provides guidance for assessing performance uncertainty and test margin. Consideration of Emergency Diesel Generator (EDG) frequency and voltage uncertainties for steady-state operation will further reduce test margin. Westinghouse has assisted several utilities in implementing WCAP-17308-NP-A to revise pump test acceptance criteria. In some cases, design basis related test acceptance criteria adjusted for EDG and instrument uncertainties have challenged the tested performance of safety-related pumps.

Examples will be provided of the impact of EDG voltage and frequency tolerances and instrument uncertainties on pump performance along with options for test margin recovery when the revised test acceptance criteria result in unacceptable pump performance. These test margin recovery options consider the relationships between pump performance and system configuration and the resulting effects on accident analysis delivered flow.

2. Materials and Methods

The basic WCAP-17308-NP-A methodology provides a general approach to account for uncertainties by adjusting pump curves, which may require supplemental analysis for certain safety analysis acceptance criteria, such as system resistance, if applicable. The WCAP methodology focuses on the impact of EDG Technical Specification Frequency and Voltage limits, treated as uncertainties, on IST limits for safety related pumps and also includes methods for applying EDG corrections to valves, fans, EDG Power, and EDG Fuel Consumption. The NRC Final Safety Evaluation (FSE) for WCAP-17308-NP-A added conditions including the requirement to evaluate impacts on other safety related components such as uninterruptible power supplies, heaters, battery chargers, etc. Some performance requirements may also be contained in the TS's or Technical Requirements Manual (TRM). Only steady-state EDG performance needs to be evaluated. Transients, e.g., EDG loading, are excluded. Inclusion criteria for pumps includes:

- FSAR Chapter 6 and 15
- Auto loaded on Diesel
- Required to run continuously

These criteria typically limit the scope to ECCS pumps and a subset of other ESF Pumps, Valves, and Fans. It is worth noting that the methodology is not NSSS dependent. The PWROG has authorized the release of WCAP-17308-NP-A to Boiling Water Reactor Owners Group (BWROG) members for their internal use. Westinghouse has applied the methodology to both PWR and BWR plants.

To summarize the analytical methodology, the impact on pump total developed head (TDH) is calculated as a total uncertainty based on the instrument and EDG uncertainties impact on TDH uncertainty derived from the pump TDH form of Bernoulli Equation (1) and a speed uncertainty equation (2).

$$TDH = \frac{144}{\rho}(P_D - P_S) + (Z_D - Z_S) - \frac{V_D^2 - V_S^2}{2g} \quad (1)$$

Where:

ρ = fluid density, lb/ft^3
g = gravitational acceleration, ft/sec^2
P_D = pump discharge pressure, psig
P_S = pump suction pressure, psig
V_D = pump discharge velocity, ft/sec
V_S = pump suction velocity, ft/sec
Z_D = pump discharge pressure sensor elevation, ft

Z_S = pump suction pressure sensor elevation, ft

$$U_{\omega} = \left[\left[\frac{V_{Nom}(f_{Nom}+|U_f|)}{(V_{Nom}-|U_V|)f_{Nom}}\right]^2 - 1\right]\left(\omega_{Synch} - \omega_{Nom}\right) + \left[\frac{(f_{Nom}+|U_f|)}{f_{Nom}} - 1\right]\omega_{Nom} \quad \text{[WCAP-17308-NP-A Eq. 5] (2)}$$

Where:

U_f = uncertainty in frequency, Hz
U_V = uncertainty in voltage, V
ω_{Synch} = synchronous speed, rpm
ω_{Nom} = nominal, asynchronous speed, rpm
f_{Nom} = frequency, Hz
V_{Nom} = nominal nameplate or supply voltage, V

The overall uncertainty of the TDH, $U_{\Delta H,Total}$ is calculated by combining individual TDH uncertainties using the square root sum of the squares SRSS method. The overall uncertainty is calculated using Equation (3). Refer to [2] for definitions of the individual terms and derivations. Note that the calculation of $U_{\Delta H\text{-}Q}$ requires the first derivative of the pump curve that can be determined either numerically or analytically.

$$U_{\Delta H,Total} = \sqrt{U_{\Delta H}^2 + U_{\Delta H-Q}^2 + U_{\Delta H-\omega}^2} \quad \text{[WCAP-17308-NP-A Eq. 7] (3)}$$

Where:

$U_{\Delta H}$ = uncertainty in pump developed head measurement, ft
$U_{\Delta H\text{-}Q}$ = uncertainty in pump developed head due to flow uncertainty, ft
$U_{\Delta H\text{-}\omega}$ = uncertainty in pump developed head due to speed uncertainty, ft

Pump Test Acceptance Criteria (TAC) based on pump curves are generated by adjusting the pump curves by $U_{\Delta H,Total}$ to account for flow and pressure instrumentation as well as the EDG frequency and voltage limits. Minimum curves are shifted up, and maximum curves are shifted down. The net effect is to tighten the allowable operating band for the pumps.

Several methods for test margin recovery can be considered, including 1) reducing the EDG frequency and voltage uncertainties, 2) reducing instrument uncertainties, 3) correcting the test data or TAC for pressure gauge location biases due to velocity head, elevation head, and friction head, 4) modification of the safety analysis pump curves.

3. Results and Discussion

Figures 1 – 6 illustrate the impact of these adjustments on a typical Intermediate Head Safety Injection Pump (IHSI). While the ASME OM comprehensive pump test (CPT) limits of required instrument accuracies of 0.5% for pressure and 2% for flow (Table ISTB-3510-1, [1]) result in a moderate loss of test margin (Figure 2) relative to the design basis safety analysis (SA) curves (Figure 1), the impact of the EDG Standard Tech Spec (STS) [5] uncertainties (2% frequency and 10% voltage) is much more pronounced (Figure 3). A similar reduction in margin is seen when pressure measurement uncertainty is reduced to 0.1% and combined with the EDG uncertainties in Figure 4. Figure 5 shows the effect of only the reduced uncertainty pressure instrumentation. Finally, Figure 6 shows the effect of reducing the frequency uncertainty to 0.3 Hz (0.5% for 60 Hz systems) and the voltage uncertainty to 5%. The reduced frequency uncertainty has a dominant effect on the margin recovery, changing the speed uncertainty from 2.3% (80 rpm) to 0.7% (25 rpm) for a nominal motor speed of 3540 rpm. When TAC are differential pressure or head as a function of flow, the adjusted curves can be used to directly calculate new TAC. Some pumps have flow-based TAC requirements that may require consideration of the system resistance and the resulting change in flow based on the adjusted curves and the resistance. Resistances may be static or dynamic, where the latter are dependent on control valve automatic response to system conditions. Systems with flow control capability may require analysis in addition to the pump curve adjustments. ECCS flow balance acceptance criteria may also be affected by the uncertainty adjustments. Plants with resistance-based flow balance criteria may need to adjust the resistances for the EDG and instrument uncertainties, depending on the relationship between pump performance and resistance criteria.

The standard ASME OM Code limits for the CPT from [1] Table ISTB-5121-1 for this pump are compared to the adjusted safety analysis limits in Figures 7 and 8. In this example, the Unit 1 pumps are shown as being tested at a higher flow rate than the Unit 2 pumps for illustration purposes. Also, the applicable OM limits are taken from an ASME OM Code edition prior to 2012 where the High Action limit was $1.03DP_r$ as opposed to $1.06DP_r$ in editions 2012 and later. Noteworthy observations include 1) the IHSI 2B Maximum Action limit is less than $1.03DP_r$ due to the safety analysis pump curve constraint, 2) the adjusted safety analysis TAC are more limiting than the OM Max Action and Min Action Limits for all pumps in Figure 7, and 3) the OM Min Alert limit is more limiting than the safety analysis TAC. For this example, the recent IST data were very close to, or exceeded, the safety analysis Max TAC. Therefore, a means to recover margin is necessary for these pumps. The result of increasing the maximum curve is shown in Figure 8.

Reduction of the EDG frequency and voltage uncertainties is already illustrated in Figures 5 and 6. The frequency uncertainty used is representative of typical EDG governors used in the industry that have speed control accuracy of 0.25% (0.15 Hz for 60 Hz systems), plus allowances for the instrument loop components. Actual voltage uncertainties may also be reduced due to regulator capability, but the voltage drop from the EDG to the motor terminals must also be considered.

Pressure and flow measurement uncertainty can be improved using modern, digital or high accuracy analog instrumentation to further reduce the total uncertainty adjustment for the pump curves. Other improvements, although not as straightforward as using high accuracy gauges can also recover margin. Some utilities have credited lower flow measurement uncertainties by calibrating the flow orifices via lab testing and also using precise installation techniques. Wear, misalignment, and reverse installation of flow measurement orifices may also contribute to what appears to be pump degradation when it is due instead to an instrumentation issue.

Correcting the TAC or test data for pressure gauge location and piping biases due to velocity head, elevation head, and friction head should be performed whenever test data is compared to vendor provided pump curve data. Vendor data are typically provided in terms of total developed head versus flow rate for a specific process fluid temperature, usually identified as specific gravity on certified test data tables and curves, and at a specific pump speed, and were determined in accordance with industry test standards such as those from the Hydraulic Institute. As such, the vendor test TDH versus flow includes these corrections which are referenced to the pump flanges. For pumps with small differences between suction and discharge piping diameters, distance of pressure gauges from pump flanges, and pressure gauge elevations, these corrections can be trivial in terms of percent of TDH, but pumps with large difference between suction and discharge pipe diameters and particularly high flow rates may require TDH correction. However, flow measurement inaccuracy or bias due to instrument deviations from design specifications such as wear or misalignment of orifices, plugging of annubar ports, and large differences in test temperature from calibration temperature may also cause measurement error requiring correction or compensation to allow proper comparison to reference data. For example, a fluid temperature variation equal to the RWST TS limit 40°F < T < 120°F can result in a variation in the differential pressure (DP) of up to 1.2%. If DP is converted to DH using the actual test temperature, this error can be eliminated.

Failure to correct or compensate for deviations from vendor test conditions or to diagnose degradation in measurement equipment can be the difference between passing or failing an inservice test. On a related note, preservice pump test results for some pumps have been observed to consistently underperform vendor certified test results. This may be due to failure to make appropriate corrections to test data, flow instrument issues, or possibly because the piping configuration deviates sufficiently from the vendor test configuration that inherent installation biases prevent the pump from developing the vendor certified performance. This can be caused by a number of factors, notably, presence of excessive numbers of pipe bends, elbows, and/or pipe reducers that are too close to the pump suction or pressure and flow instruments. Depending on the piping configuration, it may be difficult to differentiate between measurement artifact and degraded performance due to installation. A persistent inability to reproduce vendor test performance my require a thorough evaluation of the entire piping configuration. Also worth investigating is whether the pump speed matches the vendor test speed. Significant differences should trigger evaluation of the entire pump set including motor condition and electrical supply parameters.

Since the safety analysis based TAC resulted in negative maximum limit test margin for the example pump, a margin recovery analysis was completed to determine the allowable upward shift in the maximum curve. This type of analysis requires flow margin between the ECCS delivered flow rates and the safety analysis required flow rates or a determination of no impact on the accident safety analyses. The former can be accommodated when total delivered flow rates used in the accident analyses are more conservative than those determined by an updated system flow analysis. In other cases, a change to the analyzed performance of one pump may not adversely impact the total system flow from multiple pumps. In the latter case, a change in the delivered flows may not result in an adverse impact to the limiting safety analysis case. Either determination requires a coordinated evaluation of total system flow and impacts on the plant safety analyses.

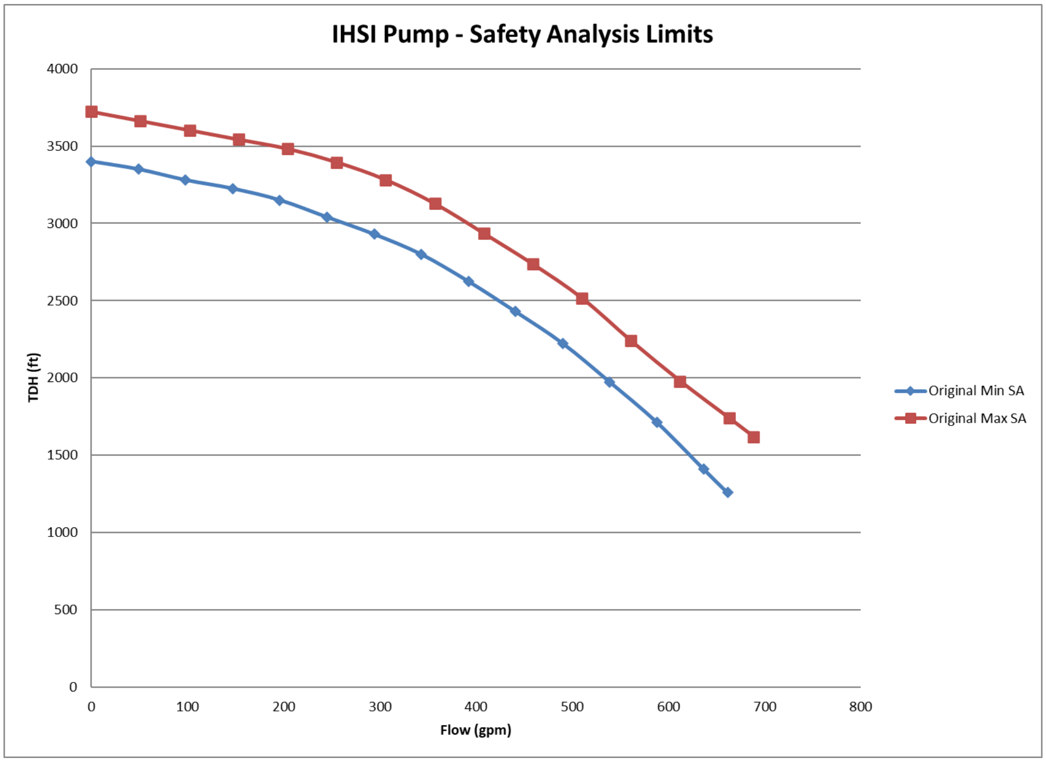

Figure 1: Typical Min and Max IHSI Pump Safety Analysis Limits

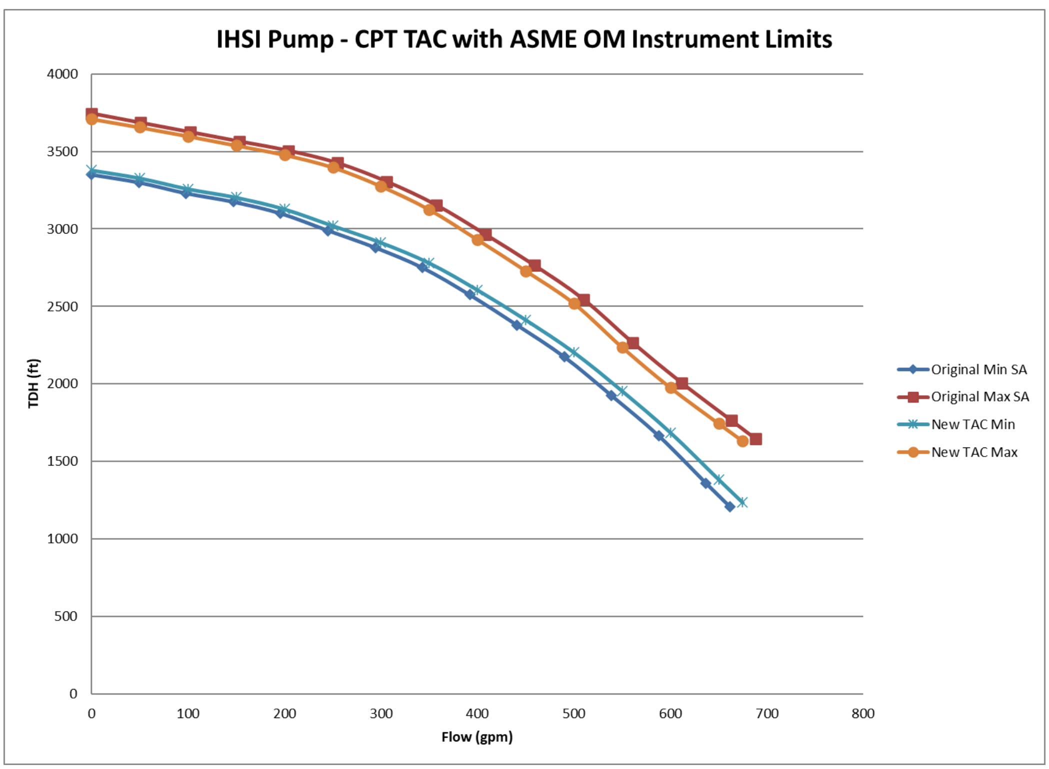

Figure 2: Min and Max IHSI Pump Safety Analysis Limits with ASME OM Instrument Uncertainties

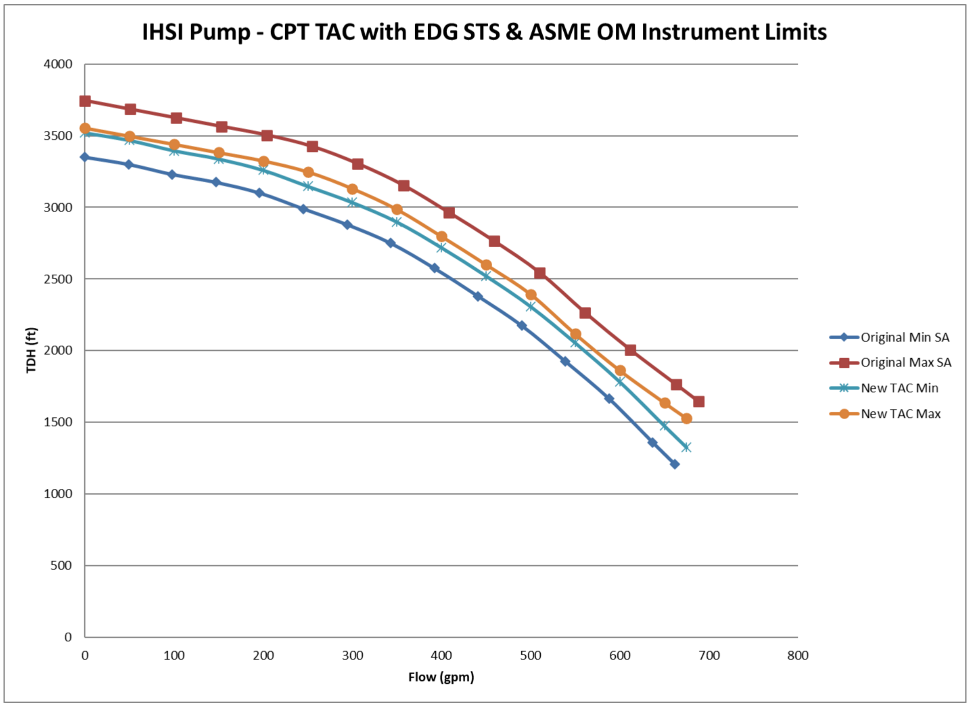

Figure 3: Min and Max IHSI Pump Safety Analysis Limits with ASME OM & EDG STS Uncertainties

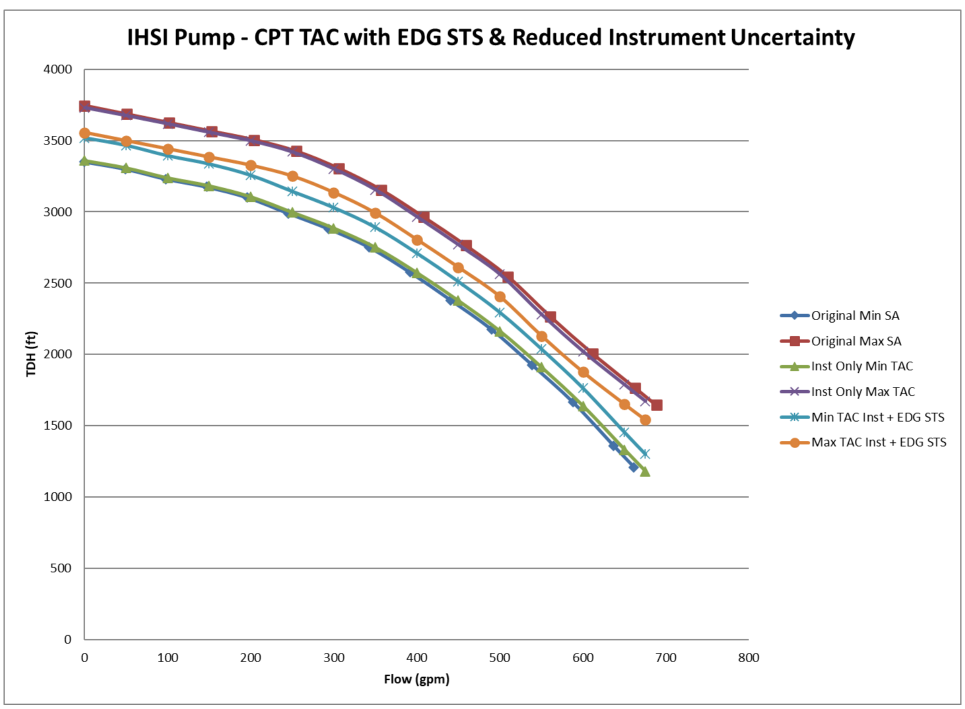

Figure 4: IHSI Pump Safety Analysis Limits with CPT Instrument & EDG STS Uncertainties

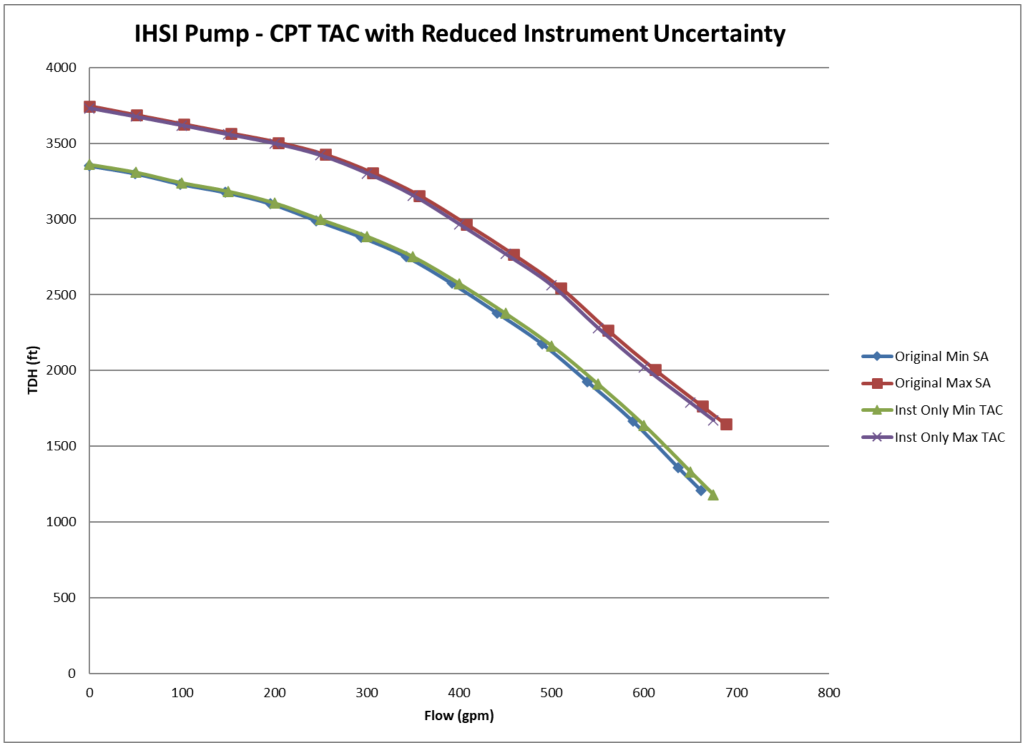

Figure 5: Min and Max IHSI Pump Safety Analysis Limits with CPT Instrument Uncertainties

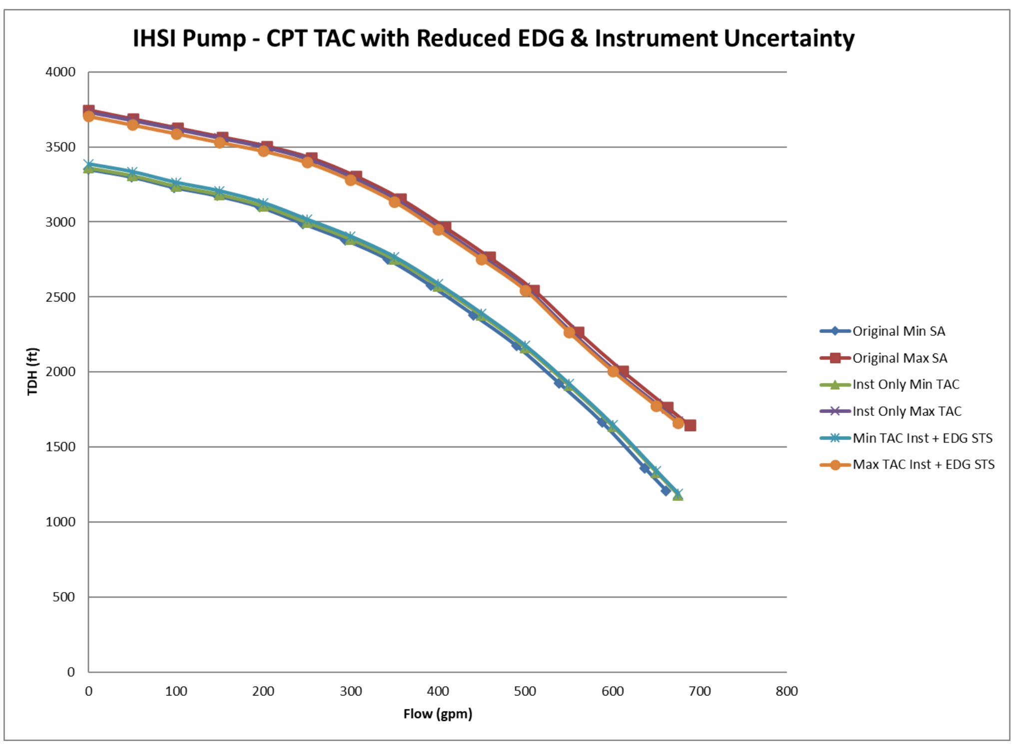

Figure 6: IHSI Pump Safety Analysis Limits with CPT Instrument & Reduced EDG Uncertainties

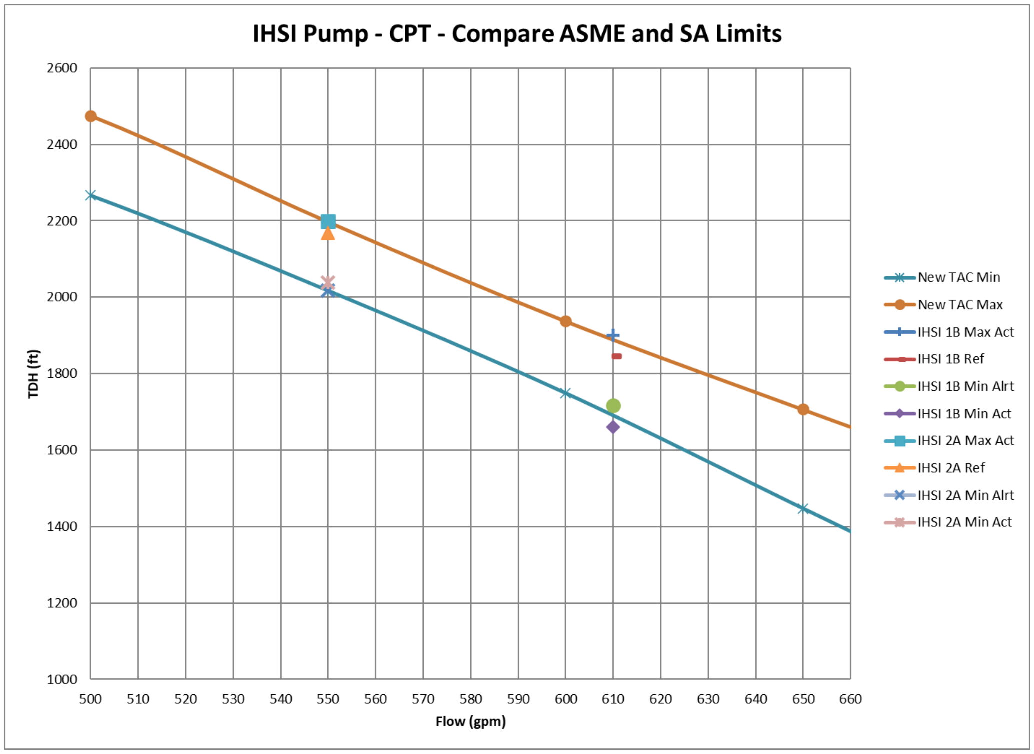

Figure 7: ASME OM Limits for Two (2) IHSI Pumps compared to Original Safety Analysis Pump Curves Using CPT Instrument and Reduced EDG Uncertainties

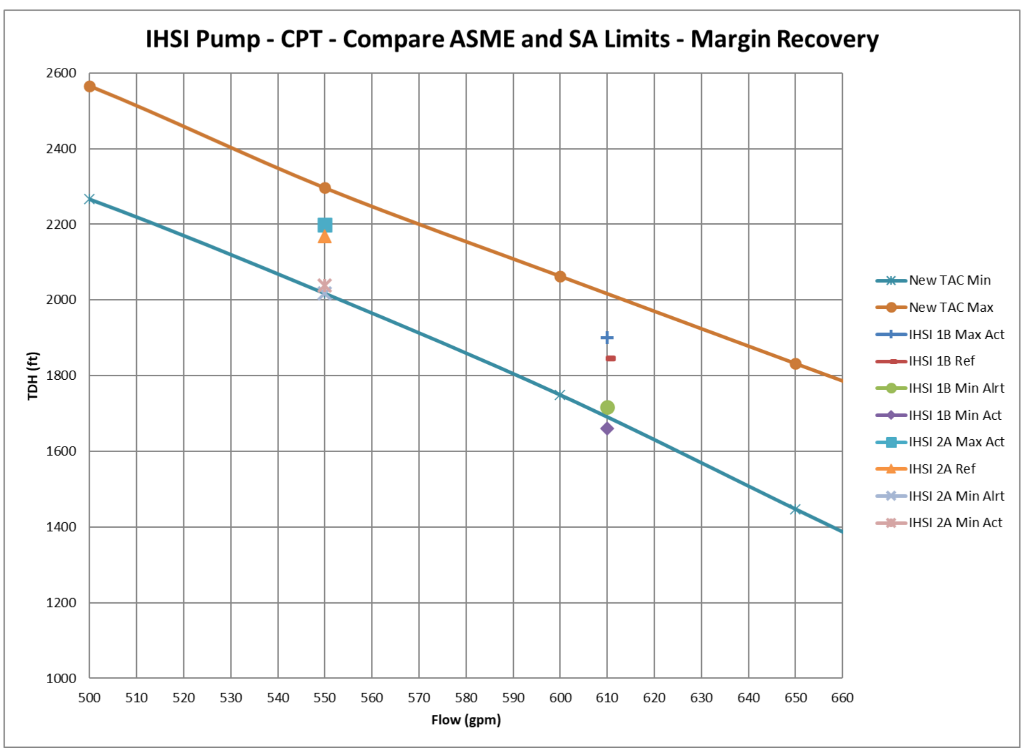

Figure 8: ASME OM Limits for Two (2) IHSI Pumps compared to Revised Safety Analysis Pump Curves adjusted for Uncertainties after Margin Recovery Analysis

4. Conclusion

Several utilities have implemented the methods of WCAP-17308-NP-A to revise pump test acceptance criteria to account for the impact of EDG voltage and frequency tolerances and instrument uncertainties on design-basis required pump performance. Options are available for test margin recovery without the need to revise safety analyses or to repair or replace pumps when the revised test acceptance criteria result in unacceptable pump performance. In extreme cases of significant pump degradation, repair or replacement may be the only option to restore design-basis required performance.

References

1. ASME OM Code, *Operation and Maintenance of Nuclear Power Plants*, Division 1, OM Code: Section IST, The American Society of Mechanical Engineers, New York, NY.

2. Westinghouse Report WCAP-17308-NP-A Revision 0, "Treatment of Diesel Generator (DG) Technical Specification Frequency and Voltage Tolerances," July 2017.

3. NRC Information Notice IN 97-90, "Use of Nonconservative Acceptance Criteria in Safety-Related Pump Surveillance Tests."

4. Title 10 Code of Federal Regulations, Chapter 1, Part 50, "Domestic Licensing of Production and Utilization Facilities."

5. NUREG-1431, Rev. 4, "Standard Technical Specifications Westinghouse Plants, " U.S. Nuclear Regulatory Commission, April 2012.

Operationally Focused Management of Pumps in Alert: Using Analysis to Remove a High Pressure Safety Injection Pump from Increased-Frequency Test Schedule

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Abstract

Pressurized water reactor designs preclude full-flow testing of certain safety-related standby pumps during power operations. This is problematic for Group B pumps that test in the alert range under comprehensive pump test conditions that are only available during refueling outages. The American Society of Mechanical Engineers (ASME) *Operation and Maintenance of Nuclear Power Plants*, Division 1, OM Code: Section IST (OM Code), committees sought to resolve this issue when new provisions were added to paragraph ISTB-6200, "Corrective Action," in the ASME OM Code, 2012 Edition, Subsection ISTB, "Inservice Testing of Pumps in Water-Cooled Reactor Nuclear Power Plants – Pre-2000 Plants." The provisions allow analysis of pump performance in lieu of testing at an increased frequency. Palo Verde Generating Station employed these rules to satisfy ASME OM Code requirements for a vibration alert range entry of its high-pressure safety injection pump without having to submit for regulatory relief or shut down to perform the test. The changes to paragraph ISTB-6200 in ASME OM Code, 2012 Edition, give plants the flexibility to ensure safe operation without undergoing extraordinary measures to accommodate testing requirements.

1. Introduction

Palo Verde Generating Station faced a dilemma in 2017 when a Group B pump tested in the alert range on vibration. The Palo Verde pressurized water reactor design prevented performing the required full-flow comprehensive test of its high-pressure safety injection pump at twice the normal frequency. The station could shut down to perform the test or seek regulatory relief. A change in the ASME OM Code gave the plant a third option: evaluate the pump condition in lieu of additional testing. The architecture of this approach has been in place for 25 years. Incorporating this strategy into the Code gives plants the flexibility to continue power operations while maintaining a focus on equipment performance and nuclear safety.

2. Materials and Methods

This paper describes the method of compliance with regulatory requirements applicable to nuclear power plants. Materials used in this method are identified as references.

3. Results and Discussion

During the 20th Palo Verde Unit 2 refueling outage in April-May 2017, the unit's B-train high-pressure safety injection pump tested in the alert range on inboard horizontal vibration during performance of the required comprehensive pump test. An internal evaluation identified the cause:

> *It has been determined that the shifting of the pump structure's resonance frequencies was most likely caused by or exacerbated by the slow degradation of the grout and delamination of the pump's base plate from the grout…. Degradation of the grout materials installed in pump pedestal supports has been observed to be the cause of this increase in pump operating vibration levels to unacceptable values.*

Maintenance and modification were performed in an effort to correct the condition. The station lubricated and cleaned the pump support pedestals to ensure adequate freedom of movement and installed a "stiffener" modification to arrest the vibration, shown in Figures 1 and 2. Post-maintenance testing showed the work reduced inboard horizontal bearing vibration below its alert range threshold. The work also changed outboard horizontal vibration performance and pushed it into the alert range.

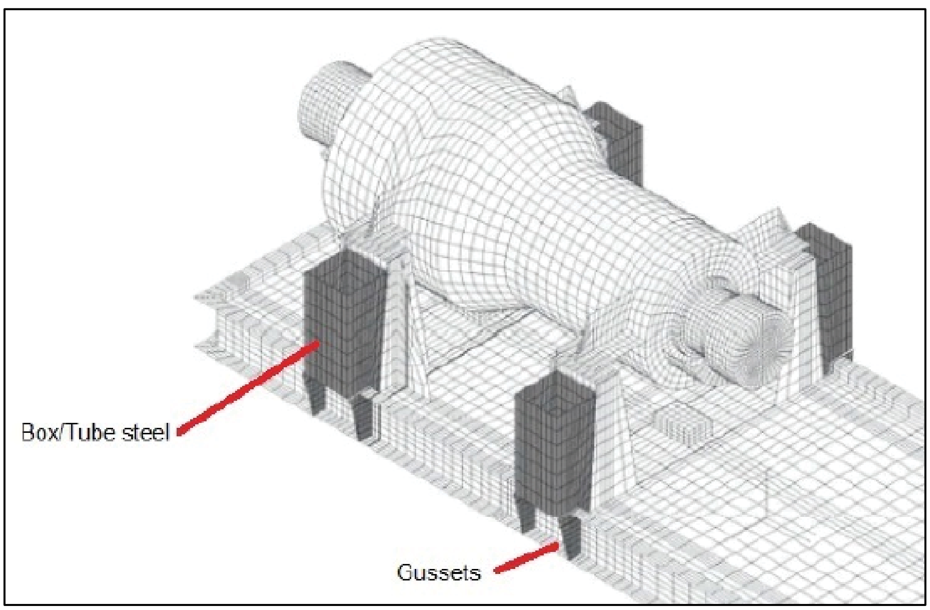

Figure 1: Rendering of the Pump 2MSIBP02 Support Pedestal Modification. Reinforcing Material is Shown in Dark Gray

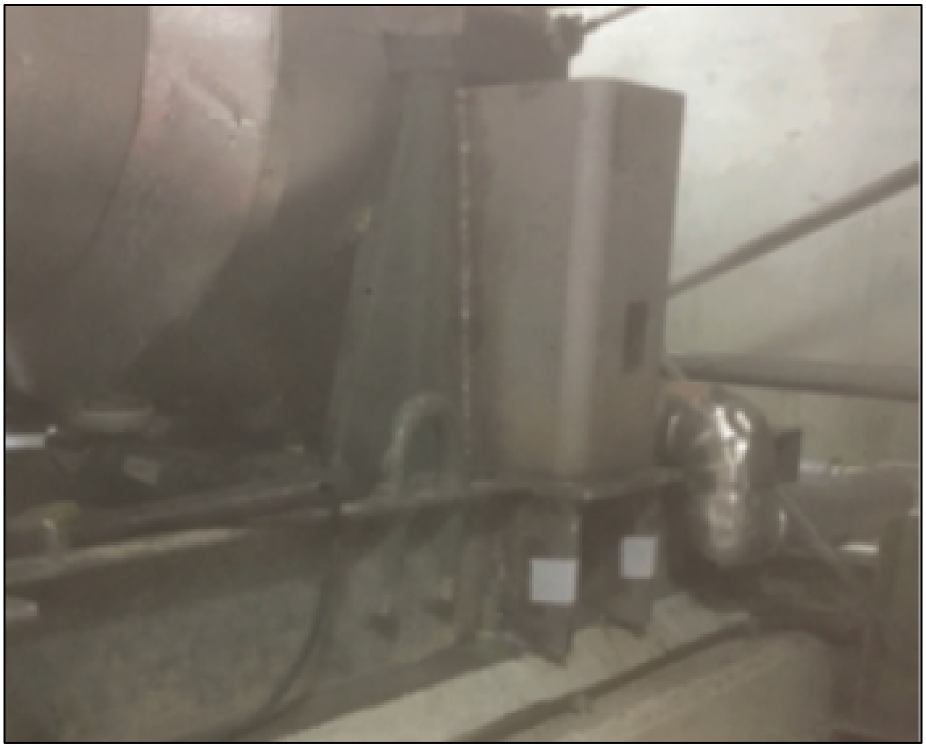

Figure 2: Post-Modification Photo of the 2MSIBP02 Pump Pedestal with Added Box Steel and Gussets

Pump natural frequency data is shown in Figures 3 and 4. Figure 3 illustrates the natural frequencies occurring at the pump's inboard and outboard supports prior to modification. Figure 4 illustrates the natural frequency at the outboard support following modification. The pump running frequency, approximately 60 hertz (Hz), is indicated by the star. The figures show how the natural frequency at the outboard support shifted, illustrating the complexity of the issue. Palo Verde was unable to completely resolve the issue during the refueling outage in which it was discovered. More time was needed to fully evaluate the pump's dynamic response and devise a permanent solution.

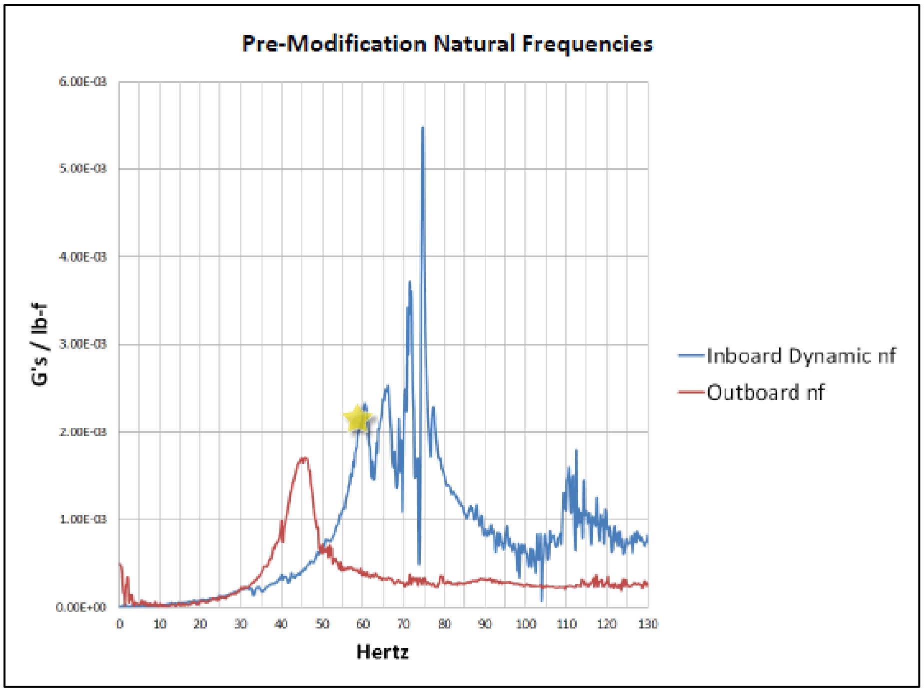

Figure 3: Vibration Resonance Condition prior to Modification of Pump 2MSIBP02

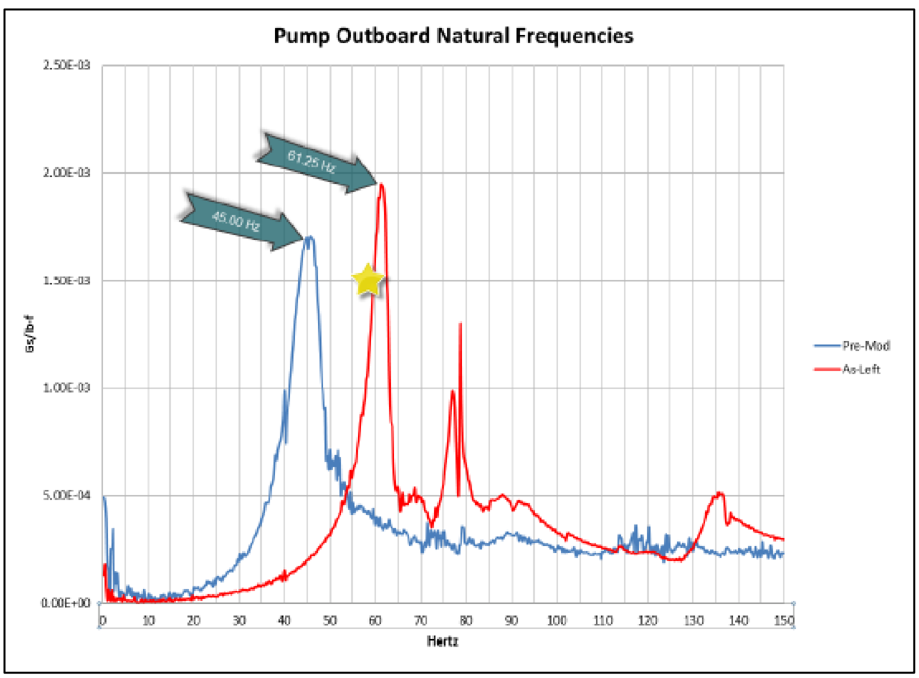

Figure 4: Vibration Resonance Condition after Modification of Pump 2MSIBP02

Palo Verde's high-pressure safety injection pump cannot be full-flow tested with the unit on line. Comprehensive testing is required once every two years but performed every 18 months when full-flow conditions are accessible during refueling outages. Testing is performed with the reactor coolant system defueled and the system at atmospheric pressure. The pump's Group B quarterly test is performed using a minimum recirculation flow line. The difference in test conditions presents an inherent disconnect. The comprehensive pump test flow is 1,080 gallons per minute (gpm) with a differential pressure reference value of 986.5 pounds per square inch (psi). The quarterly test flow is approximately 170 gpm through a fixed-resistance line; the differential pressure reference value is 1,881.6 psi. Pump shut-off head is 1,885 psi (365 psi less than the normal operating pressure of 2,250 psi absolute (psia)). Power operations are performed with the reactor critical in Mode 1. To achieve a reactor coolant system pressure less than 1,885 psia, the reactor would have to be in mode 3, defined as subcritical. Quarterly testing is performed using the minimum flow recirculation because it is the available flow path at power.

Two possible actions were considered to meet the requirements for increased-frequency testing after recording vibration data in the alert range. Palo Verde could shut down the unit to put it in a condition to perform the test or seek regulatory relief. ASME OM Code-2001 [1] was in use at the time. Subparagraph ISTB-6200(a) gives no options in responding to test data in the alert range. It states:

> *Alert Range. If the measured test parameter values fall within the alert range of Table ISTB-5100-1, Table ISTB-5200-1, Table ISTB-5300-1, or Table ISTB-5300-2, as applicable, the frequency of testing specified in ISTB-3400 shall be doubled until the cause of the deviation is determined and the condition is corrected.*

The subparagraph is clear in its requirement to double the test frequency "until the cause of the deviation is determined and the condition is corrected." This passage requires complete knowledge of the change in pump performance and action taken to resolve it. The subparagraph provides no alternatives for analysis and no options to accept a condition with a known cause. The preferred alternative was regulatory relief per Section 50.55a, "Codes and standards," in Title 10, "Energy," of the *Code of Federal Regulations* (10 CFR 50.55a), paragraph (z)(2), "Hardship without a compensating increase in quality and safety." The planning and complexity required to take a unit off line for testing and then returning it to power exceeds the complexity of developing a basis for hardship.

A well-timed 10-year update just 8 months after the alert range entry gave Palo Verde a third option. In January 2018, the station was among the first plants in the United States to adopt ASME OM Code-2012 [2], a change that included new wording in paragraph ISTB-6200. The change directly ties ISTB-6200(a) to ISTB-6200(c), giving nuclear power stations the option to evaluate pump performance in response to data in the alert range, in lieu of additional testing. Paragraphs ISTB-6200 in ASME OM Code-2001 and ASME OM Code-2012 are provided in full to illustrate the differences.

ASME OM Code-2001 states:

> **ISTB-6200 Corrective Action**
>
> *(a) Alert Range. If the measured test parameter values fall within the alert range of Table ISTB-5100-1, Table ISTB-5200-1, Table ISTB-5300-1, or Table ISTB-5300-2, as applicable,*

the frequency of testing specified in ISTB-3400 shall be doubled until the cause of the deviation is determined and the condition is corrected.

(b) Action Range. If the measured test parameter values fall within the required action range of Table ISTB-5100-1, Table ISTB-5200-1, Table ISTB-5300-1, or Table ISTB-5300-2, as applicable, the pump shall be declared inoperable until either the cause of the deviation has been determined and the condition is corrected, or an analysis of the pump is performed and new reference values are established in accordance with ISTB-6200(c).

(c) New Reference Values. In cases where the pump's test parameters are within either the alert or required action ranges of Table ISTB-5100-1, Table ISTB-5200-1, Table ISTB-5300-1, or Table ISTB-5300-2, as applicable, and the pump's continued use at the changed values is supported by an analysis, a new set of reference values may be established. This analysis shall include verification of the pump's operational readiness. The analysis shall include both a pump level and a system level evaluation of operational readiness, the cause of the change in pump performance, and an evaluation of all trends indicated by available data. The results of this analysis shall be documented in the record of tests (See ISTB-9000).

ASME OM Code-2012 states:

ISTB-6200 Corrective Action

(a) Alert Range. If the measured test parameter values fall within the alert range of Table ISTB-5121-1, Table ISTB-5221-1, Table ISTB-5321-1, or Table ISTB-5321-2, as applicable, the frequency of testing specified in para. ISTB-3400 shall be doubled until the cause of the deviation is determined and the condition is corrected, or an analysis of the pump is performed in accordance with subpara. ISTB-6200(c).

(b) Action Range. If the measured test parameter values fall within the required action range of Table ISTB-5121-1, Table ISTB-5221-1, Table ISTB-5321-1, or Table ISTB-5321-2, as applicable, the pump shall be declared inoperable until either the cause of the deviation has been determined and the condition is corrected, or an analysis of the pump is performed in accordance with subpara. ISTB-6200(c).

(c) Analysis. In cases where the pump's test parameters are within either the alert or required action ranges of Table ISTB-5121-1, Table ISTB-5221-1, Table ISTB-5321-1, or Table ISTB-5321-2, as applicable, an analysis may be performed that supports the pump's continued use at the changed values. This analysis shall include verification of the pump's operational readiness. The analysis shall include both a pump level and a system level evaluation of operational readiness, the cause of the change in pump performance, and an evaluation of all trends indicated by available data. The analysis shall also consider whether new reference values should be established and shall justify the adequacy of the new reference values, if applicable. The results of this analysis shall be documented in the record of tests (see section ISTB-9000).

In ASME OM Code-2001, subparagraph ISTB-6200(a) provides only one path for dealing with test data in the alert range: additional testing and correction of the issue. While ISTB-6200(c) refers to data in the alert range, it is titled "New Reference Values," demonstrating its intended use for rebaselining components. The subparagraph expressly states "a new set of reference values may be established" when data are obtained in the alert range. Use of the word "may" shows rebaselining is an alternative to the requirements of ISTB-6200(a) or ISTB-6200(b), and the subparagraph goes on to provide instructions for the analysis necessary to establish new reference values. The passage is silent on how to respond when new reference values are imprudent or impractical. For a vibration issue that identifies a change in component condition based on age, as was the case with the Palo Verde high pressure safety injection pump, dispositioning alert range data using ISTB-6200(c) undermines the Code's purpose to detect and monitor degradation. Rebaselining a component in response to changing equipment conditions is a slippery slope. Hypothetically, this action could be repeated until all vibration parameters are at the high limits. Palo Verde's comprehensive testing identified vibration issues stemming from a change in the condition of the grout under the pump baseplate. Rebaselining to accommodate this change was unacceptable to IST support personnel.

ASME OM Code-2012 reformats paragraph ISTB-6200, linking ISTB-6200(a) and ISTB-6200(c) without assuming rebaseline is the necessary course of action. ISTB-6200(c) is titled "Analysis" (rather than "New Reference Values") and carries the instructions for analyzing a component in response to either an alert range or action range entry. ISTB-6200(c) states "an analysis may be performed that supports the pump's continued use at the changed values." Use of the phrase "an analysis may be performed" indicates the analysis is the alternative to the requirements in ISTB-6200(a) and ISTB-6200(b). The construction makes no assumptions about the analysis outcome. This contrasts with the ASME OM Code-2001 statement that "a new set of reference values may be established," presupposing that rebaseline is warranted. The 2012 Edition of ISTB-6200(c) includes the option to rebaseline by stating "the analysis shall also consider whether new reference values should be established." This means individual plants are given the authority to make a judgement on the best method to ensure safety. Plant operators can disposition alert range data via increased-frequency testing or an analysis justifying continued operation. For pumps where no increased-frequency test can be performed, the passage drives licensees to maintain understanding of equipment performance to assure safe plant operation. For conditions where the cause of the deviation is unknown and the pump can be tested at power, plants have the option to monitor the condition with the benefit of increased-resolution data that will support sound decision-making for resolving equipment issues.

Paragraph ISTB-6200 in ASME OM Code-2012 is rooted in established regulatory guidance. The first issuance of NUREG-1482 [3] in April 1995 included an appendix explaining implementation of Generic Letter 89-04, Position 9. The position permitted quarterly testing on minimum recirculation flow supplemented by full-flow testing during outages. Appendix A to NUREG-1482 (1995) adds guidance for coping with component performance issues identified during refueling outages. It states:

> *When testing using the guidance in Position 9, if a pump is in the alert or required action range, it is recommended that efforts be made to take corrective actions during the outage and repeat the test post-maintenance. When corrective actions cannot be taken during the outage (e.g., a pump rebuild is needed, but parts are not available), or when maintenance must be performed during power operations (e.g., to clean mussel buildup from the pump internal cavity), it is recommended that testing to the extent practical during power operations be conducted following corrective actions and prior to returning the pump to service. Additionally, it is recommended that an evaluation of the results be performed and compared to historical results of both the quarterly testing on minimum recirculation and the full- or substantial-flow testing performed during outages to further ensure that the pump rebuild was adequate. To meet Position 9 guidance, the full-flow testing would be conducted at the first available opportunity.*

NUREG-1482, Revision 3, [4] in July 2020 makes a similar statement with respect to valves. Section 4.4.2 states:

> *The NRC staff would not require a licensee to shut down a plant to perform IST unless the licensee has no alternative to ensure that the operational readiness of components is maintained or a safety issue exists.*

Appendix A to NUREG-1482 (1995) and NUREG-1482, Revision 3 (2020), show NRC acknowledges the hardship in shutting down a reactor solely to perform testing. The quoted passages show how to balance testing compliance with production. Appendix A provides guidance on sufficient alternative testing and analysis when pump test conditions are inaccessible. The statement in NUREG-1482, Revision 3, appears in a discussion of valves in Section 4.4.2, but is written broadly such that it aligns with the Appendix A guidance. Use of alternatives such as analysis, available test data and new data from the accessible test conditions serve as the alternative to ensure operational readiness is maintained.

Incorporating established regulatory guidance into paragraph ISTB-6200 gives plants flexibility to ensure safety without resorting to extraordinary measures. When Palo Verde's efforts to address the vibration issue were unsuccessful, the station evaluated pump condition to support operability and return the unit to power operations. The station followed up with a cause analysis to identify the corrective actions for implementation in the next refueling outage. The vibration issue was ultimately resolved in the next refueling outage in fall 2018. Maintenance was performed to disassemble the pump and disconnect it from surrounding piping. Stresses were reduced, increasing the effective stiffness of pump pedestals and subsequently shifting the natural frequency further away from the pump running speed, shown in Figure 5. Post-maintenance comprehensive pump test data met all test criteria. Evaluation per ISTB-6200(c) drew on the component-focused cause analysis and operability support evaluations while adding assessment of overall safety injection system readiness and reviewing the pump's data trends. Through its analyses, Palo Verde developed a comprehensive understanding of pump and system condition to support safe operation. Paragraph ISTB-6200 enables stations to take credit for the corrective action analyses already being performed while enhancing the analyses with system-level and trend reviews necessary to satisfy regulatory precedents. This flexibility resolves the disconnect between the requirement to test pumps in alert at an increased frequency when plant conditions cannot support the required testing.

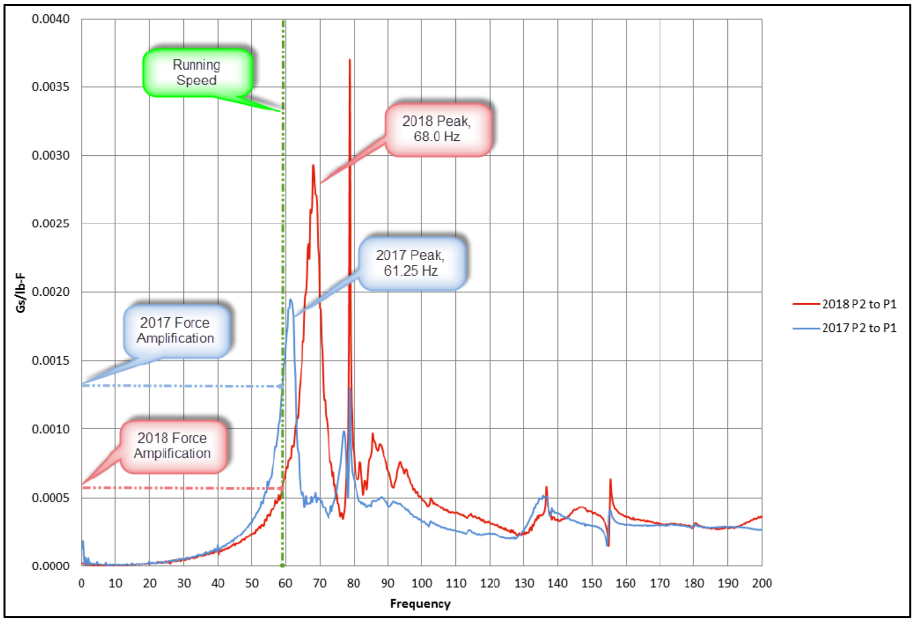

Figure 5: The High Pressure Safety Injection Pump's Natural Frequency Changed after Pump Disassembly Relieved Stresses, Effectively Stiffening the Pump Structure

4. Conclusion

Palo Verde Generating Station has successfully used the provisions of ASME OM Code, paragraph ISTB-6200, to respond to design limitations that prevent full-flow testing a specific Group B pump online. The station's high-pressure safety injection pumps are subject to vibration requirements during comprehensive pump testing that can only be performed in refueling outages. If a vibration issue puts the pump in alert, the station will use the analysis provision of ISTB-6200(c) in ASME OM Code-2012 rather than shut down to perform testing or request relief due to a hardship. The station's approach is rooted in the regulatory-endorsed framework of the ASME OM Code and its roots in regulatory guidance dating back nearly three decades. This flexibility ensures the station maintains a focus on equipment performance and safety without impacting power operations.

References

1. *ASME OM Code-2001: Code for Operation and Maintenance of Nuclear Power Plants*. The American Society of Mechanical Engineers, New York (2001).

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3. "Guidelines for Inservice Testing at Nuclear Power Plants." NUREG-1482. U.S. Nuclear Regulatory Commission, Washington, D.C. April 1995.

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ASME OM ISTB Code Vibration Changes: Vibration Calibration Frequency Response Range and Wording Changes

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Abstract

In July 2020, the Electric Power Research Institute (EPRI) Condition Based Maintenance User Group (CBMUG) held an annual meeting. During the proceedings, the group requested that an effort be made to pursue changes to American Society of Mechanical Engineers (ASME) *Operation and Maintenance of Nuclear Power Plants*, Division 1, OM Code: Section IST (OM Code), Subsection ISTB, "Inservice Testing of Pumps in Light-Water Reactor Nuclear Power Plants – Pre-2000 Plants." Two changes were requested:

- Changes to paragraph ISTB-3510 concerning calibration of vibration instruments at low frequencies.

- Changes to various locations wording concerning the use of the term "broadband (unfiltered)" vibration data.

In July 2020, EPRI submitted proposed changes to the ASME ISTB Code Committee and presented the requests during a virtual meeting.

Change 1: Operating nuclear power plants are required to follow ASME OM Code subparagraph ISTB-3510(e) calibration requirements for vibration instruments used for inservice testing. Instruments accuracy must be ± 5% from 1/3 running speed to at least 1000 hertz (Hz). The industry has historically experienced difficulty in meeting this requirement on slow speed pumps resulting in proliferation of relief requests in the late 1980s and early 1990s. Revision of NUREG-1482 in 2013 caused concerns among users in relation to the validity of the existing reliefs.

Change 2: The term "Broadband Unfiltered" is used in various locations in the ASM OM Code to describe vibration data. This terminology was common in an earlier era of analog vibration data collection equipment but is confusing to a new generation of vibration analysts accustomed to using modern digital vibration instruments.

Introduction

In June 2020, the Electric Power Research Institute (EPRI) Manager for the Condition Based Maintenance User Group (CBMUG) asked the membership for comments on the new draft EPRI Vibration Program Guide in development. The request generated several questions from members relating to terminology in the ASME OM Code, Subsection ISTB, and slow speed machines vibration calibration requirements. A conversation was started with the membership concerning the Code, and a presentation on calibration of vibration equipment was prepared to present at the July 2020 CBMUG Meeting. This meeting is a combination of EPRI Members from Nuclear and Generation sectors. The presentation outlined the requirements of the ASME OM Code, Subsection ISTB, for vibration measurement of Nuclear Safety Related Pumps that are part of facilities Inservice Test (IST) programs. Part of the presentation covered the difficulties in meeting the ASME OM Code instrument calibration requirements for low speed pumps. The guidance in NUREG 1482 for allowing relief from low frequency calibration requirements changed with Revision 2 in 2013. The NRC no longer granted relief due to hardship of the calibration requirements at low frequencies. This called into question the validity of many existing relief requests in the industry.

During a post presentation discussion, the membership requested that an effort be made to pursue changes to ASME OM Code, Subsections ISTB and ISTF. Two changes were requested:

- Changes to paragraphs ISTB-3510 and ISTF-3510 concerning calibration of vibration instruments at low frequencies.

- Changes to various locations wording concerning the use of the term “broadband (unfiltered)” vibration data.

In mid-2020, an EPRI team wrote a white paper explaining proposed changes to the ASME OM Code, Subsection ISTB, and submitted it to the ASME OM Code Subcommittee on Pumps in July 2020.

Discussion of Change 1:

The ASME OM Code, Subsection ISTB, has contained wording requiring calibration of vibration equipment across a frequency range from 1/3 running speed to at least 1000 hertz (Hz) since its inception. The NRC approved the use of ASME OM Code-1988 Part 6 in ASME *Boiler and Pressure Vessel Code* (BPV Code), Section XI, Code Case N-465, which was noted in NRC Regulatory Guide 1.147. The requirement to calibrate down to 1/3 running speed was also present in the previous OM guidance in IWP-4520(b). The difficulties in meeting the 1/3 running speed requirements on low-speed pumps has been an issue since it was first required and was discussed in a 1992 NRC White Paper “Recommendations on Frequently Encountered Relief Requests”[5]. Most facilities with low-speed pumps requested relief from the Code required calibration, and it was granted based on hardship due to the unavailability of sensors capable of meeting the calibration requirements at such low frequencies. In 2013, Revision 2 of NUREG 1482 was released with wording that called those earlier approved relief requests into question. The wording was carried over into Revision 3 (July 2020).

Background:

Operating nuclear power plants are required to measure vibration on pumps in the IST Program. NUREG-1482 states that pumps in the IST program will meet the requirements of ASME OM Code, Subsection ISTB. Specifically, ISTB-3510(e) states, “The frequency response range of the vibration-measuring transducers and their readout system shall be one-third minimum pump shaft rotation speed to at least 1,000 Hz.” Table ISTB-3510-1 requires the instruments accuracy to be ± 5%.

An informal survey of the CBMUG membership found industry operating experience that identified the on-going challenges for utilities to meet the one-third rotation frequency response range requirements in low-speed applications. The survey of operating nuclear power units found that many (most) have older existing relief requests dating from the 1980s and early 1990s to exclude them from the calibration requirements for monitoring vibration of low-speed equipment. Specifically, low speed applications under 600 revolutions per minute (rpm) with many cases of pumps with speeds of approximately 200 rpm and extreme cases identified under 50 rpm. Most of these low-speed pump cases were reciprocating positive displacement (PD) pumps such as Charging Pumps at Pressurized Water Reactors and Standby Liquid Control System (SLCS) Pumps in Boiling Water Reactors. These positive displacement reciprocating pumps typically run at speeds between 190 rpm to 300 rpm depending on the plant design. The Code required instrument calibration for a 190 rpm reciprocating charging pump requires instrument calibration at ±5% accuracy down to 1 Hz. Meeting the ±5% accuracy of the one-third frequency range with modern accelerometers and vibration meters was not practical in the 1990s and resulted in the proliferation of relief requests at that time. As stated in Revision 2 to NUREG 1482, at least one manufacturer now offers a sensor that nominally meets the required sensitivity and accuracy. It is still very difficult and costly to meet the specification and finding labs that can calibrate to a low frequency is even more challenging. The Code requirement that the instrument and sensor be calibrated as a loop and meet the 1/3 running speed to 1000 Hz criteria adds an additional challenge, as low-frequency vibration sensors capable of meeting the 5% criteria at 1 Hz are not capable of meeting the criteria at 1000 Hz when paired with an instrument and calibrated as a loop. During a review of available vibration accelerometers in the industry, only one manufacturer was found that can provide a sensor that meets the ±5% accuracy from 1 Hz to over 1000 Hz. When paired with a vibration data collection instrument, this accuracy often cannot be achieved when calibrated as a loop over the entire frequency span. At least one plant has implemented a compromise solution that requires using two separate sensors on low-speed equipment, a low-frequency sensor and a “normal” sensor to meet the entire range and each data point must be measured twice during testing, once with each sensor. This compromise solution does not technically meet the “letter” of the Code, but meets the “intent” to monitoring the frequency range at the required accuracy. The expensive low frequency sensors are very fragile and are replaced often. Calibration is expensive and time consuming.

NUREG-1482 Revision 2 (October 2013) wording changes:

The following new sections in Revision 2 to NUREG-1482 caused many sites to question the validity of their existing approved relief requests that had existed since the 1980s and 1990s.

> *Page 5-8*
> *The minimum frequency response range requirement is established from one-third of the minimum pump shaft rotational speed to at least 1000 Hz in order to encompass all noise contributors that could indicate degradation. Instruments with a frequency*

response range that meets these requirements for slow-speed pumps may not be widely used. However, the unavailability of instruments, alone, does not constitute adequate justification for obtaining relief or approval of an alternative; however, it may be a significant element in the justification. The NRC has observed that, because of technology advancement and research in the field of instrumentation, vibration measuring transducers meeting the Code requirements can now be procured from various suppliers at reasonable costs. Additionally, frequencies less than running speed may not be indicative of problems for certain types of bearings; however, subharmonic frequencies may be indicative of rotor rub, seal rub, loose seals, or coupling damage. The type of bearings and other subharmonic concerns would typically be discussed in the justification for relief.

Similar statements are made in Section 5.13 on page 5-17 of NUREG-1482:

5.13 Vibration-Measuring Transducers
Subsection ISTB of the OM Code requires that the frequency response range of vibration measuring transducers and their readout system be from one-third of the minimum pump shaft rotational speed to at least 1,000 hertz (Hz). Licensees have proposed alternatives to this OM Code requirement in accordance with 10 CFR 50.55a(a)(3) for pumps with low shaft rotational speeds. Similar alternative requests submitted by licensees have been withdrawn following discussion with the NRC. The proposed alternatives state that the procurement and calibration of vibration-measuring transducers and their readout systems for the lower end of the OM Code-specified range were hardships because of the limited number of vendors supplying such equipment, the level of equipment sophistication, and equipment cost. The NRC typically authorized these alternative requests in the past. However, vibration-measuring transducers and their readout system can now be procured from various suppliers at a reasonably low cost due to technology advancement and research work performed in the field of instrumentation. ***Therefore, licensee requests to use this alternative are generally no longer authorized by the NRC.***

The statement in NUREG-1482 that "measuring transducers meeting code requirements can now be procured from various suppliers at reasonable costs" was not confirmed by research of the EPRI team. During that research, only one major manufacturer of vibration sensors offered a sensor that met the calibration requirements between 1 Hz and 1000 Hz, and it was much more expensive than a standard sensor. The discussion in NUREG-1482 also does not touch on the significant issues of meeting the calibration requirement in metrology testing when calibrating the measuring system as a loop and the difficulties in verifying calibration below 4 Hz.

Code Change:

Calibration Issues:
±5% accuracy and ISTB-3510-1 & ISTF 3510-1

The requirement of meeting the ±5% accuracy at 1/3 running speed of slow speed pumps stated in ASME OM Code, Tables ISTB-3510-1 & ISTF 3510-1, is a burden to meet on the very low speed pumps with no significant value added for this level of accuracy.

Accelerometers have improved over the years of achieving low frequency response, but the vibration meters still have issues when integrating from acceleration to velocity or displacement in this low frequency area. The Code requires data be trended in velocity units which requires one integration from an accelerometer output. NUREG-1482 also recommends (but does not require) that pumps running less than 600 rpm be measured in displacement requiring a double integration. Each integration introduces low frequency noise (ski slope) into the spectral data used to calculate the overall vibration.

The main standard used for calibration in the industry is ISO [International Organization for Standardization] 16063 Part 21, which only discusses calibration down to 4 Hz. This standard uses a reference transducer certified by NIST (National Institute of Standards and Technology). To meet the ±5% accuracy of the measuring the system as a whole, the NIST traceable sensor used as a reference must be even more accurate, typically on the order of ±1% across the frequency range. Procuring a NIST traceable sensor of the required accuracy at 1 Hz is very costly. The traceable sensor must be sent back to NIST periodically (typically every two years) for certification at a similar cost.

In order to calibrate below 4 Hz, ISO 16063 Part 11 is often employed which uses laser interferometry. The need for expensive and fragile NIST traceable reference sensors calibrated below 4 Hz or laser interferometry equipment makes calibration below 4 Hz at ±5% very costly and extremely difficult. Combined with the lack of options for sensors that can meet the calibration requirements, this constitutes a significant burden for the plants needing to meet Code requirements for low speed equipment. Given the nature of vibration fault signals at low frequencies, this level of accuracy is not typically necessary to detect changes in slow speed running components. The fragility of low frequency accelerometers also means they are found out of calibration more often, causing an increased burden in proving past operability of pumps they were used on in the previous testing cycle.

Code Change Details:

The requested change to the Code asked for a change to the calibration requirements at low frequencies. The percent accuracy change is for slow speed running pumps under 600 RPM to have a calibration accuracy of ±15% from 1/3 turning speed from 1 Hz to 4 Hz and ± 5% for > 4 Hz to a minimum of 1000 Hz. This change allows for use of less expensive, more robust sensors and less expensive NIST traceable metrology to be used in the calibration process.

<u>Justification</u>:

- Obtaining ISO 16063 calibration below 4 Hz is a significant hardship for plants at the ±5% accuracy stated in ASME OM Code, Tables ISTB-3510-1 and ISTF 3510-1.
- After polling the industry for slow speed equipment 600 rpm or less in the IST program, all but one fell in the 190 to 600 rpm range. The one exception was some metering pumps in an IST Program that ran at 37 rpm. The license was granted relief on vibration testing of those pumps. With the proposed bottom of the frequency response range being 1 Hz or 60 rpm, the instrumentation will identify vibration problems that may occur even if accuracy is only ±15%. For example, Roller Bearing failure would be identified by increase in harmonic's of running speed with bearing noise showing up at 60 Hz or higher. Sleeve or Journal bearing wear or clearance problems would show up as harmonics out to 7 times running speed. Rubs at ½ times running speed and sub-synchronous oil whip or whirl would be still be identified, but the accuracy of the

amplitude would be within ±15%. Mechanical looseness would show up as 1 times running speed up to 3 times running speed. Poor bearing fit will show up as harmonics up to 10 times running speed. The data below 4 Hz actually adds very little value on slow speed machines but would still be detectible with the decreased accuracy.
- The majority of slow speed pumps subject to the code requirements are positive displacement pumps similar to the Gaulin positive displacement pumps used in many Pressurized Water Reactors and similar pumps used for Standby Liquid Control in Boiling Water Reactors. The NRC granted relief to Palo Verde in 2017 for measuring vibration at frequencies below running speed on these type pumps after an analysis indicated that sub-synchronous frequencies were not applicable to determining health. This relief was granted, not based on hardship, but rather based on the low value of measuring frequencies below running speed on these type pumps.
- As an example using ±15% accuracy: Detected amplitude of 0.1 inches per second (in/sec) at a frequency less than 4 Hz could be inaccurate up to a maximum of 0.015 in/sec, which is an insignificant amplitude and within the typical range of variation of vibration.

Based on these arguments, the ASME OM Code Committee agreed to place a change as shown below to the Code on the ballot. The requested change was approved and will be part of the next revision.

Current Wording	**Suggested Wording**
(e) Frequency Response Range The frequency response range of the vibration-measuring transducers and their readout system shall be from one-third minimum pump shaft rotational speed to at least 1,000 Hz.	*(e) Frequency Response Range* *(1)* For pumps operating at or above 600 rpm, the frequency response range of the vibration-measuring transducers and their readout system shall be from one-third minimum pump shaft rotational speed to at least 1,000 Hz. *(2)* For slow speed pumps operating below 600 rpm, the frequency response range of the vibration-measuring transducers and their readout system shall be no lower than 1 Hz to at least 1000 Hz.

Revised Tables ISTB/ISTF-3510-1

Quantity	Group A and Group B Test, %	Comprehensive and Baseline Tests, %	Pump Periodic Verification Test, %
Pressure	+/- 2	+/- ½	Note (1)
Flow Rate	+/- 2	+/- 2	Note (1)
Speed	+/- 2	+/- 2	Note (1)
Vibration			N/A
> 4Hz to 1000 Hz Note (2)	+/- 5	+/- 5	
1 Hz to 4 Hz Note (3)	+/- 15	+/- 15	
Differential Pressure	+/- 2	+/- ½	Note (1)

NOTES:
(1) Instrument accuracy shall be selected by the Owner such that the required parameters are verified when instrument accuracy is taken into account for the pump periodic verification test flow and pressure.
(2) ±5% accuracy from > 4 Hz or 1/3 pump shaft rotation speed to at least 1,000 Hz in native units (accelerometers in acceleration, velocity transducers in velocity, etc.)
(3) Transducers used on slow speed running pumps under 600 RPM - ±15% accuracy in native units (accelerometers in acceleration, velocity transducers in velocity, etc.) from 1 Hz to 4 Hz and ± 5% > 4Hz to a minimum 1000 Hz.

The requested change was placed on Ballot 20-2355, and approved for the next published ASME OM Code edition expected in 2022.

Discussion of Change 2:

<u>Background</u>

An inquiry was submitted to the EPRI CBMUG (Condition Based Maintenance Users Group) concerning the use of the term “broadband (unfiltered)” vibration data. With new Engineers coming into the field of Condition Based Maintenance (CBM), this term has created confusion and the intent is not well understood. With vibration measurement technology evolving, the ASME OM Code uses terminology more common to an earlier analog era. The Code was originally written when analog was the standard method of measurement. Digital measurement influences on the ASME OM Code have manifested in the form of code cases and changes over time, but some of the terminology such as “broadband (unfiltered)” is confusing to a new generation of vibration analysts.

This wording was acceptable during the use of analog vibration meters. Today's digital meters have the means to clean up (filter) out errors that occur during the integration of acceleration to velocity and displacement particularly in the very low frequency applications. Overall values are now calculated in modern instruments from Fast Fourier Transform (FFT) spectral data, which are based on a minimum and maximum frequency range. The modern data are just as accurate as older "unfiltered" analog instrument outputs, but the wording in the Code leaves the user uneasy because of the "filtering" that has taken place. The intent of the phrase "broadband (unfiltered)" originally was understood to be an overall value measurement from a minimum low frequency (normally fixed in the instrument) to as high a frequency as the instrument could "see." The vibration calibration section of the Code dictated that the sensor and instrument were calibrated and accurate from one-third running speed to a minimum of 1,000 Hz. Specifically, the terminology denoted an overall value across a broad frequency range and not filtered to a specific harmonic such as 1X or 2X, etc. Earlier analog instruments typically had a switch or knob that could select between "filtered" or "unfiltered" with the filtered setting limiting the displayed output to the vibration energy at 1x running speed or a multiple. Many in the CBMUG were not aware of the design of the older analog meters and were confused by the terminology in the Code.

The terms "broadband" and "unfiltered" occur multiple times throughout the vibration section of the ASME OM Code.

Recommendation: Change the following wording of "Broad band (unfiltered)".

Current Wording (example)	Suggested Wording
Vibration (displacement or velocity) shall be determined and compared with the reference value. Vibration measurements shall be broadband (unfiltered). If velocity measurements are used, they shall be peak. If displacement amplitudes are used, they shall be peak-to-peak.	Vibration (displacement or velocity) shall be determined and compared with the reference value. Vibration measurements shall be ~~broadband (unfiltered)~~an overall value, without filtering of velocity or displacement. If velocity measurements are used, they shall be peak. If displacement amplitudes are used, they shall be peak-to-peak.

Justification:

The terminology of broadband (unfiltered) was originally intended to ensure data collected was across the entire frequency response range. It was not intended to be collected at specific frequencies, like 1X or 2X. In today's terminology, the words "an overall value, without filtering, of velocity or displacement" mean the same thing, and remove the confusion of the words, "Broadband unfiltered."

The term broadband (unfiltered) will need to be changed in the following places:

ISTB-5121 Group A Test Procedure (d)

ISTB-5123 Comprehensive Test Procedure (d)

ISTB-5221 Group A Test procedure (d)

ISTB-5223 Comprehensive Test Procedure (d)

ISTB-5321 Group A Test Procedure (d)

ISTB-5323 Comprehensive Test Procedure (d)

ISTF-5120 Inservice Testing (c)

ISTF-5220 Inservice Testing (c)

ISTF-5320 Inservice Testing (c)

The requested change was placed on Ballot 20-3975, and approved for the next published edition expected in 2022.

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4. Robert Binz, ASME OM Code Committee, rbinz@proceduresolutionsmgmt.com

5. R. Scott Hartley and Clair B. Ransom, RECOMMENDATIONS ON FREQUENTLY ENCOUNTERED RELIEF REQUESTS – Idaho National Engineering Laboratory

6. NUREG-1482, Revision 2 (October 2013)

Condition Monitoring for Pumps

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The following paper is the opinion of the authors. Nothing in this paper is to be construed as the opinion or direction of the ASME OM Standards Committee.

Abstract

The American Society of Mechanical Engineers (ASME) *Operation and Maintenance of Nuclear Power Plants*, Division 1, OM Code: Section IST (OM Code) describes a check valve condition monitoring program in Appendix II, "Check Valve Condition Monitoring Program," which has been utilized by Owners at numerous nuclear power plants to improve testing of check valves. Use of this similar approach for pumps is expected to also improve testing of pumps.

Comprehensive Pump Testing was originally intended to address not just the pump, but the use of the pump drivers and associate pump electrical system components to monitor pump health as is currently done for motor actuated valves. The draft comprehensive test requirements included taking motor current pump electrical components, as well as an oil sample, but those requirements were not allowed to go into the final Code language, e.g., motor current signature requirements. The reason was that this was considered including the motor in IST and was not in the ASME OM Code scope. However, the motor, in that case, was used to verify acceptable pump operation only. Also, enhanced vibration techniques, such as spectral analysis, were also considered.

This paper will present the use of pump condition monitoring as a method to enhance IST and, in some cases replace traditional pump IST intervals, similar to what is done for check valve condition monitoring. The proposed pump condition monitoring program will rely on the revised OM-14 guidance.

1. Introduction

This paper provides a discussion of the need for a Code Case that establishes pump condition monitoring (PCM) program requirements for those pumps tested in accordance with Subsection ISTB or ISTF of ASME *Operation and Maintenance of Nuclear Power Plants*, Division 1, hereinafter referred to as the Code.

This paper additionally establishes that the current O&M Subgroup on Rotating Equipment draft of OM-14 is the main contributor to, and source of, the largest part of the proposed PCM program.

2. The Case for a Condition Monitoring of Pumps

The ASME OM Code contains a check valve condition monitoring program (Reference OM Code, Appendix II) that has been utilized by Owners at numerous nuclear power plants to improve testing of check valves. Use of a similar approach for pumps is expected to also improve testing of pumps such that Owners will be able to enhance detection of degradation and machine faults.

The following issues are associated with the development of the ASME OM Code, Subsection ISTB, Comprehensive Pump Test (CPT) requirements. The CPT was intended to include both improved and additional testing technologies than those currently required by the OM Code.

(1) CPT was originally intended to address not just the pump, but the use of the pump driver and associated pump electrical system to monitor pump health as is currently done for motor actuated valves. Pump drivers and their associated electrical components would require utilization of additional test and examination technologies. An Oak Ridge presentation on nuclear industry pump failures was presented to the ASME OM Standards Committee that identified a need for the Code to include pump electrical system components, since many were a large contributing factor for nuclear pump failures. And, excepting deep draft pumps, electrical system components were usually the cause of a pump failing Inservice Testing (IST) requirements. The draft CPT requirements included taking motor current, e.g., motor current signature requirements, but those requirements were not allowed to go into the final Code language. The reason was that the draft CPT inclusion of motor IST caused concern that the motors were not within the ASME OM Code scope. As evident by the success of IST of motor operated valves, the pump and associated electrical system components, including the motor, need to be part of pump IST.

(2) CPT requirements were originally intended to address the use of vibration equipment that would provide state-of-the-art vibration testing, i.e., spectral analysis was not required, nor is it currently required, by the OM Code for some of the most important pumps at the nuclear power plant. The OM Standards Committee has had several presentations that advised that the Code should be requiring spectral analysis when monitoring nuclear safety related pumps. The original comprehensive testing schemes included use of state-of-the-art vibration testing, but those requirements were not allowed to go into the final Code language because they required expert interpretation of results (i.e., they were not ‘go or no go’ tests).

(3) CPT requirements were also originally intended to include sampling of oil as a tool of the IST Program. That too, although part of the original ASME BPV Code, Section XI, IWP requirements, was kept out of the Code, again, because it required the interpretation of results.

3. What Does Pump Condition Monitoring Look Like?

The first steps in establishing PCM is an assessment of the design, test history, and maintenance history of a pump, and the pump electrical system, to determine those additional PCM technologies, acceptance criteria, and equipment to be included in the PCM program that will enhance detection of degradation and machine set faults.

The technologies and parameters to be considered, in addition to Code hydraulic test, include enhanced vibration analysis, lube oil analysis, thermography, motor current signature analysis, motor electrical parameters, and process and equipment parameters.

(1) Vibration Analysis. Vibration analysis involves the Owner utilizing state-of-the-art equipment for collecting and analyzing spectral vibration data to monitor the mechanical

condition of rotating equipment. Vibration analysis is the primary technology, along with lube oil analysis, used in a condition monitoring program.

(2) Lube Oil Analysis. Lube Oil Analysis involves analyzing oil properties, including those of the base oil and its additives, and identifying the presence of contaminants and wear debris.

(3) Thermography. Thermography is used for detecting and measuring variations in the heat emitted by various regions of a body and transforming them into visible signals that can be recorded photographically. Thermography can be used as a tool for identifying potential equipment faults, performing post maintenance retests, and trending the condition of equipment components subject to temperature degradation.

(4) Motor Current Signature Analysis. Motor current signature analysis involves analyzing motor current data in the frequency domain.

(5) Motor Electrical Parameters. Current, phase balance, and winding temperatures can provide indication of degradation to predict impending failure.

(6) Process and Equipment Parameters. Process and equipment parameter variations may impact condition monitoring results. Applicable process and equipment data should be collected in conjunction with the equipment condition monitoring data.

(7) As applicable and available, when performing walkdowns of the equipment or during operator rounds and data collection, visual, auditory, olfactory, and tactile observations of equipment sounds, smells, discoloration, casing and bearing housing temperature changes or leaks can identify potential equipment problems that left unattended could lead to equipment failure.

4. Revise the Code, or Code Discussion

There are several methods to provide PCM provisions in the ASME OM Code. One method is an outright revision to the Code: most likely a new Appendix. This method would mean that condition monitoring would require the publishing of the new Code edition as well as acceptance of the regulator. Another method is to produce a Code Case. The advantage of a Code Case is that it need not wait for a new edition, although it would still need approval from the regulator to use. Also, it need not be applied to all pumps in a program. A user can target this monitoring program as needed.

5. Conclusion

Pump condition monitoring is expected to improve the assessment of pump operational readiness through real-time, or near real-time, condition monitoring that will allow alternatives to the frequency of IST requirements of the ASME OM Code, Subsection ISTB or ISTF, for assessing the operational readiness of pumps in nuclear power plants.

6. Latest Status

There are two ASME OM Code Committee Records for Pump Condition Monitoring. Both of these actions have been approved. The actions are:

Pump Condition Monitoring Program Code Case, ASME C&S Connect Record #20-1855

ASME OM Guides, Part-14, Condition Monitoring of Rotating Equipment in Nuclear Power Plants, ASME C&S Connect Record #21-2056.

Acknowledgements

ASME OM Committee SG Rotating Equipment

References

ASME OM Code

Valves

Track Chair: Mark Gowin, Tennessee Valley Authority

Optimized Compliance with Supplemental Indication Requirements: Leveraging Non-Intrusive Techniques, Preexisting Line-Ups and Programs to Meet 10CFR50.55a(b)(3)(xi)

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Abstract

To ensure safe operation of the United States' nuclear power plants, the U.S. Nuclear Regulatory Commission (NRC) enacted Section 50.55a, "Codes and standards," in Title 10, "Energy," of the *Code of Federal Regulations* (10 CFR 50.55a), paragraph (b)(3)(xi), requiring the verification of valves' capability to control plant process conditions. Palo Verde Generating Station implemented the requirement with a focus on crediting existing operational and testing activities, iterating to optimize implementation. The station credits valve diagnostics, operational activities, and component testing programs wherever possible. Where testing and operations are insufficient to meet the requirement, phased-array ultrasonic equipment is used to verify stem-disc connection integrity. Palo Verde is fully compliant with the requirements of 10 CFR 50.55a(b)(3)(xi). This suggests compliance at other pressurized water reactors can be achieved primarily by documenting existing plant activities with minimal new testing activities required.

1. Introduction

Palo Verde has discovered through implementation of the requirement to obtain supplemental indication for valves in nuclear safety service that compliance can be achieved largely by crediting existing plant activities. From 2017 through 2019, the station performed the scoping and implementation efforts needed to meet the requirements of 10 CFR 50.55a(b)(3)(xi). The station identified a method of compliance for all 152 safety-related, position-indicated valves consistent with the requirements of (b)(3)(xi) and the framework of American Society of Mechanical Engineers (ASME) *Operation and Maintenance of Nuclear Power Plants*, Division 1, OM Code: Section IST (OM Code). The methods include diagnostic testing, operational use of valves and required testing, and existing regulatory programs. Just 2 valves required the use of phased-array scanning technology to assure stem-disc integrity when existing activities were found to be insufficient. These results show how nuclear operators can validate valve capability to control plant processes primarily through existing activities. Compliance with 10 CFR 50.55a(b)(3)(xi) requires power stations to become cognizant of how plant operations and testing methods are providing supplemental indication of valve position indication.

2. Materials and Methods

This paper describes the method of compliance with regulatory requirements applicable to nuclear power plants. Materials used in this method are identified as references.

3. Results and Discussion

The supplemental position indication requirement of 10 CFR 50.55a(b)(3)(xi) applies to 152 valves across 13 systems at Palo Verde. The scope was identified by reviewing inservice testing (IST) program procedures for all active Category A and B manual and power-operated valves that perform a safety function as described in the station's IST basis document, and passive Category A and B valves equipped with remote position indication. Excluded from this review were self-actuated valves (relief valves, safety valves, and check valves), valves that are identified as exempt from testing per ASME OM Code, paragraph ISTA-1100 or ISTC-1200, and passive Category A and B valves without remote position indication.

In 2017, the NRC revised 10 CFR 50.55a by adding condition (b)(3)(xi). The requirement states:

> *OM condition: Valve Position Indication. When implementing ASME OM Code, 2012 Edition, Subsection ISTC–3700, "Position Verification Testing," licensees shall verify that valve operation is accurately indicated by supplementing valve position indicating lights with other indications, such as flow meters or other suitable instrumentation, to provide assurance of proper obturator position.*

The requirement applies to licensees using ASME OM Code-2012 [1]. The scope is limited to position-indicated valves because the requirement is written to apply to ASME OM Code, Subsection ISTC, paragraph ISTC-3700. The condition requires nuclear licensees to ensure valves can perform their function to start or stop plant processes, as evidenced by the phrase "shall verify." This phrase shows licensees are required to make an observation that valves actively control plant process. The indications that verify accurate valve indication are at the discretion of individual plants. The phrase "such as flow meters or other suitable instrumentation" is an interjection in the sentence; it serves to illustrate potential "indications." The interjection is an example of the indications rather than a constraint, as shown by the open-ended phrase "or other suitable instrumentation." Plants have the freedom to select how valves are verified to satisfy 10 CFR 50.55a(b)(3)(xi).

Condition (b)(3)(xi) modifies ISTC-3700 requirements on supplemental indication observations while retaining flexibility in complying with the condition. ISTC-3700, titled Position Verification Testing, states:

> *Valves with remote position indicators shall be observed locally at least once every 2 yr to verify that valve operation is accurately indicated. Where practicable, this local observation should be supplemented by other indications such as use of flow meters or other suitable instrumentation to verify obturator position. These observations need not be concurrent. Where local observation is not possible, other indications shall be used for verification of valve operation.*
>
> *Position verification for active MOVs shall be tested in accordance with Mandatory Appendix III of this Division.*

ISTC-3700 is similar to (b)(3)(xi) in its discussion of supplemental indications. The Code paragraph uses the phrase “should be supplemented” to show it is recommending supplemental indication of valve operation rather than requiring it. This “should” sentence continues with a construction similar to condition (b)(3)(xi), demonstrating the intention of the authors of condition (b)(3)(xi) to change the “should” of ISTC-3700 to “shall.” Condition (b)(3)(xi) does not modify any subsequent sentences in ISTC-3700 nor invalidate any part of paragraph. The condition solely changes “should” to “shall.” Therefore, ISTC-3700 remains applicable except where specifically modified by condition (b)(3)(xi). Provisions of ISTC-3700 that permit non-concurrent observations of supplemental indications and delegation of position indication requirements to Mandatory Appendix III for active motor-operated valves (MOVs) remain in effect.

Frequency requirements for implementing condition (b)(3)(xi) are embedded in ASME OM Code-2012. Paragraph ISTC-3700 specifies a 2-year frequency for position indication verification and delegates active MOV position indications to ASME OM Code, Mandatory Appendix III. Subparagraph III-3300(e) of Appendix III states, “Remote position indication shall be verified locally during inservice testing or maintenance activities.” Condition (b)(3)(xi) requires nuclear power plants to “verify that valve operation is accurately indicated by supplementing valve position indicating lights with other indications…” The observations required by (b)(3)(xi) support the requirement to perform local observation. Supplemental indication observations made concurrent with position indication verification clearly satisfy the requirement to supplement position indication. Therefore, supplemental indications recorded during inservice testing or maintenance of active MOVs satisfies the requirement. For all other valves, ISTC-3700 states, “These observations need not be concurrent.” This provides flexibility in meeting the supplemental indication frequency requirement. Palo Verde’s position is that supplemental indication observations made more frequently that the requirements of ISTC-3700 and III-3300(e) adequately supplement the local observation requirement. This is consistent with the precedent of Code Case OMN-20, Inservice Test Frequency, which states: “All periods specified may be reduced at the discretion of the owner (i.e., there is no minimum period requirement).” Conversely, supplemental indication observations made less frequently than the requirements of ISTC-3700 and III-3300(e) fail to adequately supplement the local observation requirement. This gives plants latitude to credit various testing and operational activities that meet the supplemental indication frequency requirements.

Palo Verde sought to minimize the development of new testing that would require special plant conditions for the identified scope of valves. To implement (b)(3)(xi), it was assumed that most, if not all, of the valves are operated or tested in a manner that provides supplemental indication. Valve diagnostics and pump test line-ups were considered first because they provide ready access to supplemental indication information. Through this process, new testing opportunities were identified that required changes to existing procedures and creation of a new procedure to document successful performance of operational activities. The station also performed local leak rate testing (LLRT) at shortened intervals to meet the 2-year requirement of ISTC-3700 until an alternative could be approved. Less than 10 percent of valves in scope were not routinely operated in a manner that satisfies (b)(3)(xi). The station responded by resurrecting an old position indication test methodology and altered the plant start-up sequence.

MOV diagnostics provide supplemental indication satisfying (b)(3)(xi) for gate valves and butterfly valves with a visible unwedging peak. Examples of the data traces are shown in Figures 1 and 2. Figure 1 shows stem thrust versus time during the opening stroke of a gate valve. Figure 2 shows stem torque versus time during the opening stroke of a butterfly valve.

The traces show the measured parameter, thrust or torque, achieves a peak after stem relaxation and before the running load. This peak serves to “verify that valve operation is accurately indicated… to provide assurance of proper obturator position,” as required by (b)(3)(xi), because it shows the stem-disc connection is intact. A sheered connection results in no friction forces resisting stem motion; the peak is absent when friction is absent. Motor-operated globe valve diagnostics illustrate this. Globe valves provide no resistance to opening from a fully seated position and lack an unwedging peak as shown in Figure 3. Therefore, positive identification of the unwedging peak provides supplemental indication for a motor-operated gate or butterfly valve. To credit this identification, Palo Verde relies on its diagnostic testing process, which requires marking of the unwedging peak. Additionally, the diagnostic testing procedure was revised to direct valve technicians to write a condition report when the peak is absent. MOV diagnostics are credited for 55 of the 152 valves in scope, more than a third of population.

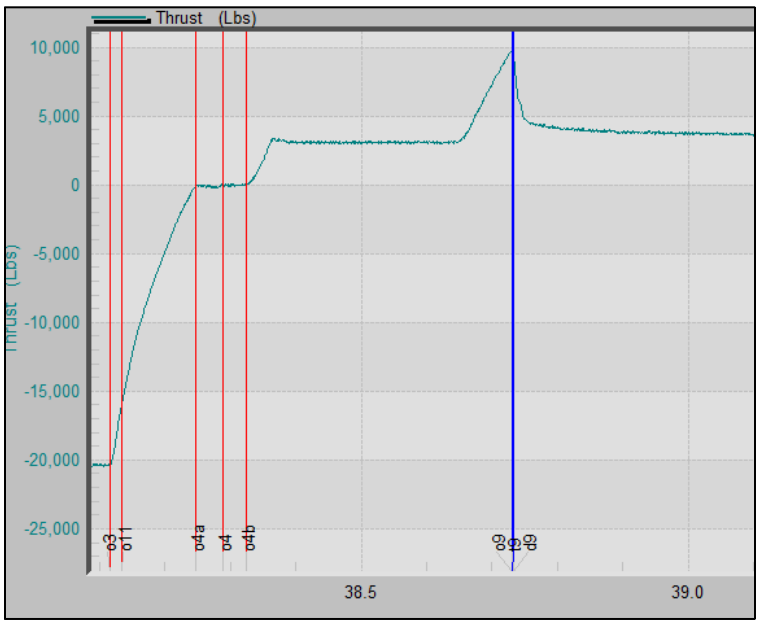

Figure 1: Plot of Stem Thrust versus Time during the Opening Stroke of Motor-Operated Gate Valve 1JSIAHV0684, a Shutdown Cooling Heat Exchanger Isolation Valve.

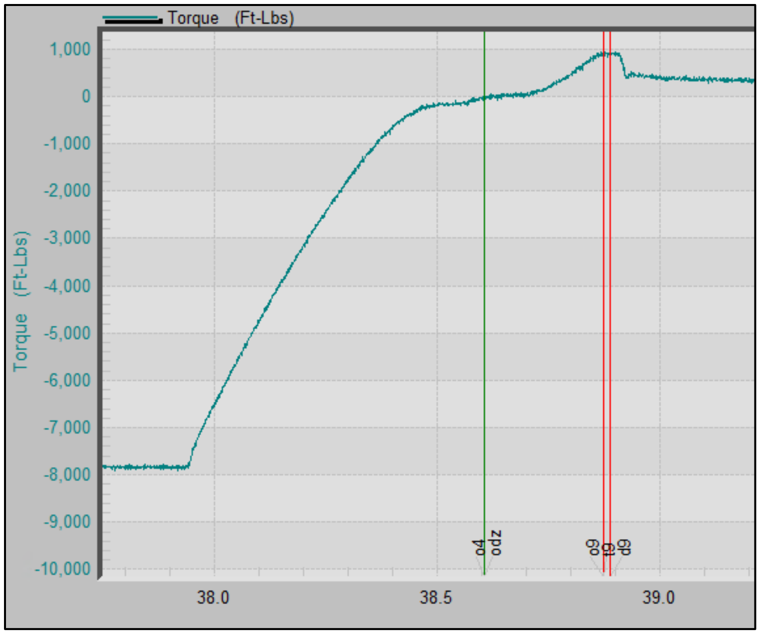

Figure 2: Plot of Stem Torque versus Time during the Opening Stroke of Motor-Operated Butterfly Valve 3JSIAUV0674, a Containment Sump to Safety Injection Pump Suction Valve.

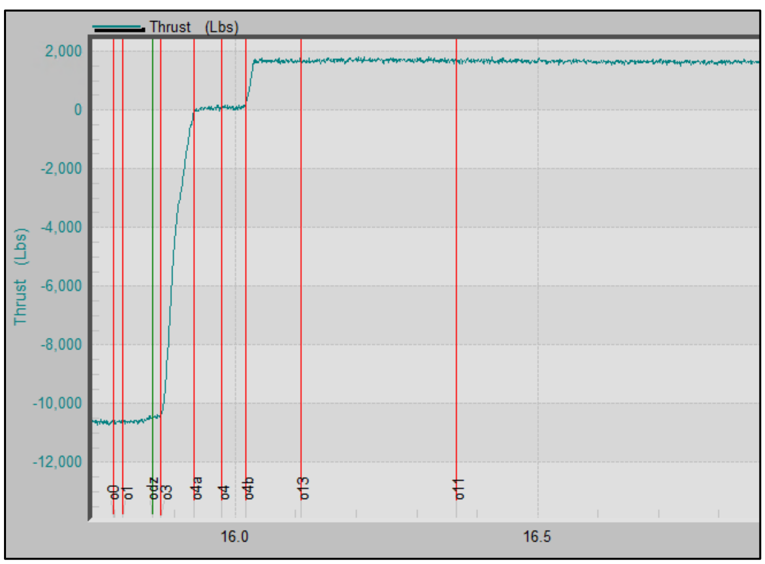

Figure 3: Plot of Stem Thrust versus Time during the Opening Stroke of Motor-Operated Globe Valve 2JAFCHV033, an Auxiliary Feedwater Flow Control Valve.

Existing pump and valve tests can verify supplemental indication because valves are already being used for plant process control. Examples include safety injection pump testing and check valve testing.

Palo Verde's low-pressure safety injection (LPSI) pumps are tested quarterly at minimum recirculation flow and at full-flow conditions during shutdown cooling operations in refueling outages. The difference in alignments means valves that are restraining flow in the quarterly test are permitting flow in the comprehensive test, and vice versa. Figures 4 and 5 illustrate this for valve SIBUV0668, the LPSI pump recirculation to refueling water tank. Figure 4 shows the alignment and flow path used for full-flow testing of the LPSI pump during comprehensive pump testing in refueling outages. During the test, motor-operated globe valve SIBUV0668 is closed to preclude recirculation flow to the refueling water tank (RWT). To verify closure of this valve, operators check for no flow to the refueling water tank using a flow meter downstream of SIBUV0668 and that all other downstream valves are open. Figure 5 shows the flow path during quarterly minimum recirculation flow testing. Operators validate SIBUV0668 open by reading a flow meter downstream of SIBUV0668. The procedural framework for these observations predates the requirements of (b)(3)(xi), therefore validating valve operation required only minor procedure changes to ensure operators are validating the expected result for a valve used to control flow in an existing test. This is advantageous because SIBUV0668 is not usually operated in dynamic conditions that would allow direct observation of the initiation or cessation of flow. This is permissible because ISTC-3700 states that supplemental indication observations "need not be concurrent." Position indication verification for SIBUV0668 is performed during the MOV's diagnostic test. Supplemental indication is performed more frequently than the diagnostic test, therefore supplemental indication adequately supports the position indication verification.

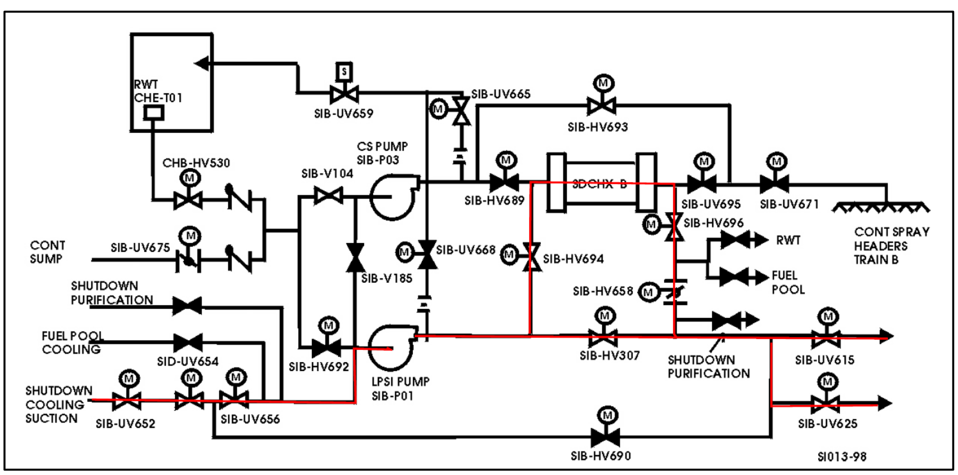

Figure 4: Illustration of the Flow Path used for Full-Flow Comprehensive Pump Testing of LPSI Pump SIB-P01.

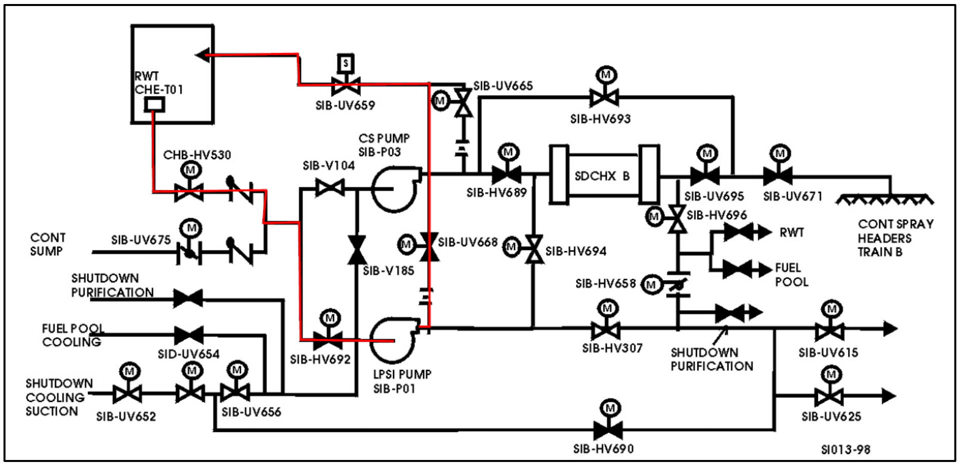

Figure 5: Illustration of the Flow Path used for Quarterly Minimum Recirculation Flow Testing of LPSI Pump SIB-P01.

Check valve and leak testing can provide opportunities for supplemental indication observations. Valve SIBUV0332, a position-indicated air-operated globe valve, requires supplemental verification and is in the flow path when applying high-pressure safety injection pump (HPSI) head pressure to SIBV533, a HPSI long-term recirculation check valve subject to leak testing per Technical Specifications. To obtain supplemental indication, operators apply HPSI pressure to SIBUV0332 and record the pressure between SIBUV0332 and SIBV533. Operators then open SIBUV0332, applying HPSI pressure to SIBV533 for its leak test, and record the pressure between the valves. The observed increase in pressure between SIBUV0332 and SIBV533 validates the SIBUV0332's ability to restrain HPSI pressure when closed and permit HPSI pressure when open. Previously, operators applied HPSI pressure directly to SIBV533 without first restraining pressure with SIBUV0332. Only minor procedure changes were required to modify the test to comply with (b)(3)(xi) for SIBUV0332.

Operational activities constitute nearly a quarter of the Palo Verde supplemental indication observations. Forty of the 152 valves are observed during routine refueling outage evolutions required to achieve plant shutdown and start-up activities. The ASME OM Code has a precedent for this in paragraph ISTC-3550, Valves in Regular Use. It states:

> *Valves that operate in the course of plant operation at a frequency that would satisfy the exercising requirements of this Subsection need not be additionally exercised, provided that the observations otherwise required for testing are made and analyzed during such operation and recorded in the plant record at intervals no greater than specified in para. ISTC-3510.*

The paragraph is specific to valve exercise. It establishes that operational activities – the use of valves to control the plant – satisfy valve exercise requirements provided the exercise is adequately recorded, the results are analyzed, and the records are retained. The paragraph is instructive for implementing (b)(3)(xi). Plant evolutions, particularly during refueling outages, provide a natural test for verifying valve process control capability. Palo Verde reviewed its (b)(3)(xi) scope to identify the valves used for plant control at least once per 18-month refueling cycle. The population includes:

- Safety injection tank fill valves. The tanks are drained and filled each refueling outage.
- Shutdown cooling flow control valves, including those shown in the flow path in Figure 4. Palo Verde uses both shutdown cooling trains each refueling outage.
- Radwaste containment isolation valves. The containment radwaste sump inventory is maintained via automatic level control.
- Reactor coolant pump seal injection valves. The system is placed in service when reactor coolant pumps are started to support plant heat-up.
- Letdown isolation valves. The letdown line is placed in service during plant start-up.

The station developed a surveillance procedure to record supplemental indications observed each refueling outage. Operating procedures were modified to drive operators to record successful process control in the new surveillance procedure. The new procedure includes acceptance criteria for each valve and direction to respond if the criteria are unmet. The procedure is retained as a plant record. The process ensures Palo Verde maintains awareness and a record of valve capability in accordance with (b)(3)(xi) without the burden of developing unique testing for each valve. Valves for which only one position is verified during refueling outages are verified closed via other activities, such as local leak-rate testing.

Local leak-rate testing provides a short-term and long-term solution for meeting (b)(3)(xi) requirements for containment isolation valves. During initial implementation, Palo Verde identified a scope of valves for which closure testing was not readily achievable through operational activities or surveillance testing. Valves in this group, and their operational obstacles, include:

- Reactor coolant pump seal injection and seal bleed-off
    - Flow through these lines is present whenever reactor coolant pumps are running. Isolation to observe flow cessation is impractical because it isolates pump seal cooling water.
- Reactor coolant system letdown lines
    - Transfers reactor coolant system water to the chemical and volume control system for dilution at power. Isolation to observe flow cessation is impractical because these valves are an input to pressurizer level control.

Many valves in this group required leak rate testing at up to 54-month intervals (4.5 years). It was necessary to short-cycle these intervals to ensure observations of valve closure were made at periodicities required by the ASME OM Code. The added cost of resources to establish test conditions for up to seven additional leak-rate tests per outage was considered onerous by IST personnel and the station. Palo Verde developed an alternative per 10 CFR 50.55a(z)(1) to resolve the issue. The authorized alternative [2] allows the station to perform supplemental indication closure verifications at frequencies controlled by the 10 CFR Part 50, Appendix J program. Crediting the Appendix J program at longer test periods provides an acceptable level of quality and safety because leak testing applies added rigor. Testing per Appendix J documents volumetric leakage, compared with supplemental indication testing standard to verify that valve operation is accurately indicated. Eleven of the 152 valves in the scope of (b)(3)(xi) credit Appendix J with obtaining supplemental closure indication. Validating closure per Appendix J provides value to power stations because it avoids duplication of effort.

Eight of the 152 valves in scope of (b)(3)(xi) lacked an operational or testing use that verifies valve indication. These were resolved by resurrecting an old test methodology and altering the plant's start-up sequence to create the necessary test conditions.

Palo Verde has six steam trap isolation valves on its main steam system, with operating conditions that did not lend themselves to supplemental indication. All six air-operated globe valves separate the safety-related portion of the main steam system from non-essential steam traps. The traps drain condensation from the steam lines while retaining steam. The valves are not regularly operated in a manner that validates flow or no-flow conditions because there is no operational reason to flow past the traps. While researching test opportunities, it was discovered that the valves were originally solenoid-operated, and a test methodology providing supplemental indication was available in archived procedures. ISTC-3700 requires the observation of supplemental indication when stem movement cannot be observed, as was the case for the predecessor solenoid-operators used in the steam trap isolation valve application. To test the valves, operators throttle open a steam trap bypass valve, creating a flow path to the main condenser downstream of the isolation valve. The isolation valve is then exercised, and steam flow noise initiation and cessation are observed by an operator stationed at the valve. This methodology, designed for solenoid-operated valves, was adopted and applied to the air-operated valves.

Palo Verde has two main steam isolation valve bypass valves that are not routinely operated. The 4-inch, air-operated globe valves provide a flow path around the 28-inch main steam isolation valves to minimize differential pressure across the larger valve prior to opening during plant start-up. However, this is an "off-normal" evolution. Palo Verde's standard practice is to warm up the secondary side with the main-steam isolation valves open. To preserve this methodology, the station attempted to use phased-array ultrasonic testing of the valves during its 1R21 refueling outage in spring 2019. The results were mixed. Valve 1JSGEUV0183 was satisfactorily observed opening and closing due to liquid water that collected in the line. Valve 1JSGEUV0169 disc travel could not be observed because the pipe was dry. With no non-intrusive techniques available and no operational activities to credit, Palo Verde altered the plant start-up sequence for the next refueling outage to validate valve capability. The station now heats up the secondary side through the bypass valves. The bypass valves are cycled during heat-up and a steam generator pressure increase is observed. Figure 6 illustrates the increasing pressure trend in the unit 3 steam generator number 2 during plant start-up after the fall 2019 refueling outage. The trend shows a spike in pressure when valve 3JSGEUV0183 is briefly cycled to observe supplemental indication. The sudden increase in pressure validates valve closure, while the return to the normal pressure trend validates the valve open position.

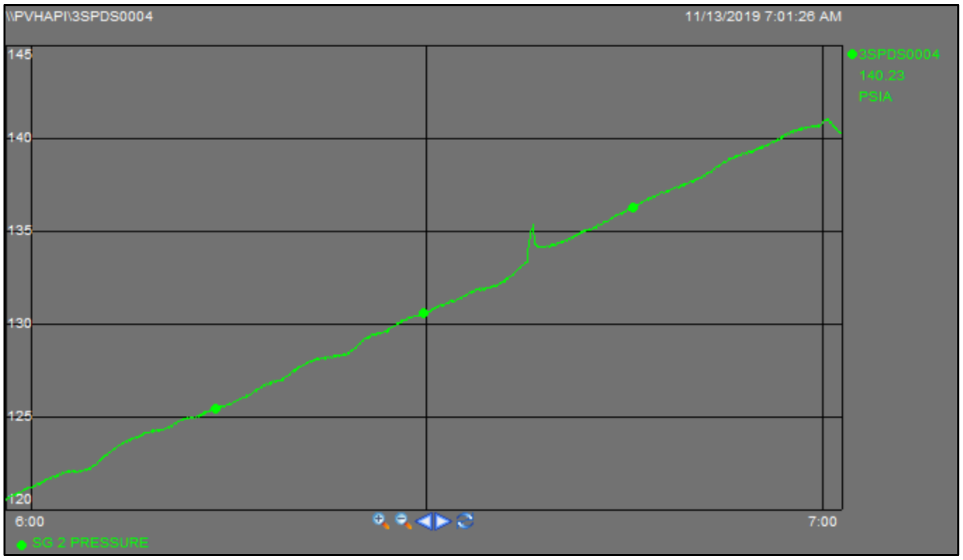

Figure 6: Steam Generator Pressure Trend during Heat-Up in a Refueling Outage. Pressure Spikes Briefly when Cycling a Main Steam Isolation Valve Bypass Valve.

Phased array ultrasonic testing provides insight into valves for which existing tests and operational activities cannot support supplemental indication in both directions. Palo Verde performs phased array scans of two valves each refueling outage to satisfy supplemental indication requirements of (b)(3)(xi): CHNUV0514, a boric acid makeup to charging pump suction isolation valve, and CHEHV0532, a refueling water tank isolation valve. Palo Verde performs boron injection flow-path verifications each refueling outage, providing supplemental indication that the valves are open. However, testing, operation and system configuration do not allow verification of the valves' ability to isolate flow. CHEHV0532, a fail-open air-operated globe valve with power removed, is kept open at all times and is only closed briefly during a flow-path verification to ensure the spent fuel pool can deliver flow to the charging pumps' suction. CHNUV0514 is a normally closed motor-operated globe valve that discharges to the charging pump suction header. There are no flow indicators or other instrumentation in the line to demonstrate flow isolation. To satisfy (b)(3)(xi) for CHEHV0532 and CHNUV0514, Palo Verde credits the valves' ability to pass flow during boron injection flow path testing and performs phased array scans during the valves' once-per-cycle exercise tests. Phased array testing provides direct observation of disc movement. Figure 7 shows phased array scan data for valve CHNUV0514 in Palo Verde Unit 3. Figure 8 is a plot of the data. These observations "verify that valve operation is accurately indicated" by demonstrating open capability to pass flow and showing disc movement to and from the closed position with non-intrusive techniques. The test methodology provides insight for any valve operated with water in the piping, regardless of susceptibility to stem-disc separation.

Data Point	Scan [sample]	Time [sec]	UT [inch] in Metal	UT [inch] in Water	Avg. Travel Velocity [inch/sec]	Travel Time [sec]	Travel Dist. [inch]
1	690	58.97	10.145	2.608			
2	1038	88.72	10.145	2.608	0.000	29.744	0.000
3	1190	101.71	25.679	6.601	0.307	12.991	3.993
4	1298	110.94	25.679	6.601	0.000	9.231	0.000
5	1402	119.83	9.624	2.474	-0.464	8.889	-4.127
6	1626	138.97	9.624	2.474	0.000	19.145	0.000

Figure 7: Phased Array Ultrasonic Test Data from CHNUV0514 in Palo Verde Unit 3.

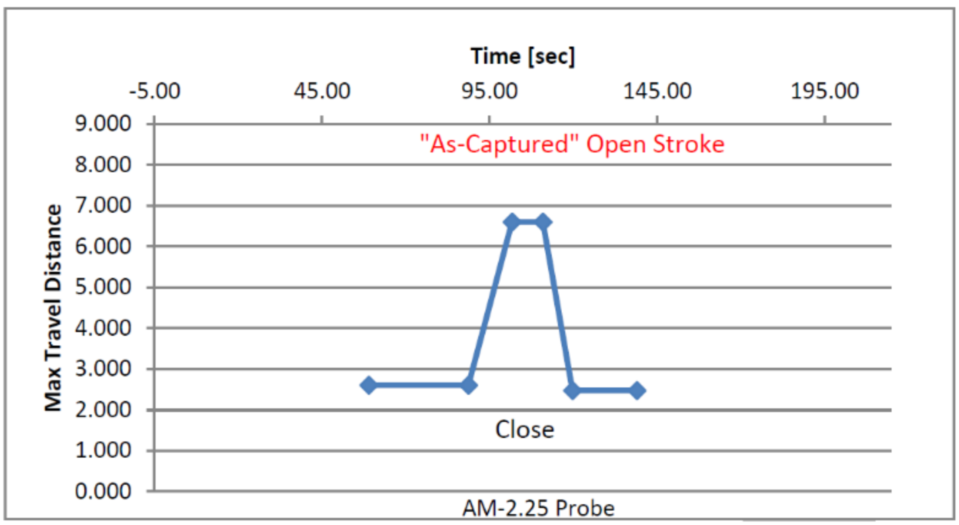

Figure 8: Plot Of "UT [Inch] In Water" Vs Time from Figure 7.

4. Conclusion

Palo Verde complies with 10 CFR 50.55a(b)(3)(xi) requirements to obtain supplemental indication of valve position through a combination of operational activities and existing testing per the IST Program and Appendix J program. The station's supplemental indication architecture was built with a focus on compliance, followed by identification of opportunities to refine implementation. Refinements include identifying the need to alter plant start-up sequence, apply non-intrusive techniques, and request a regulatory alternative to credit local leak-rate testing at extended intervals. Palo Verde uses these activities to maintain awareness of safety-related valve capability to control plant process conditions, satisfying the ASME OM Code and 10 CFR 50.55a.

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NRC Inspection Manual Inspection Procedure 71111 Attachment 21N.02: Design-Basis Capability of Power-Operated Valves Under 10 CFR 50.55a Requirements Inspection Implementation Update and Lessons Learned*

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Abstract

On July 26, 2019, the NRC issued Inspection Procedure 71111, Attachment 21N.02 (IP 71111.21N.02), "Design-Basis Capability of Power-Operated Valves Under 10 CFR 50.55a Requirements." The objective of this inspection procedure is to assess the reliability, functional capability, and design basis of risk-important power-operated valves (POVs) as required by Section 55a, "Codes and Standards," in Part 50, "Domestic Licensing of Production and Utilization Facilities," of Title 10, "Energy," in the *Code of Federal Regulations* (10 CFR 50.55a). The NRC staff has implemented this inspection procedure at operating nuclear power plants in the United States (U.S.) since January 2020, and has gained lessons learned through implementation of and feedback from the inspections. The staff has held a public meeting with nuclear power plant licensees to discuss the lessons learned from the inspection activities in December 2020. This paper describes the status of the ongoing NRC staff activities for POV inspections at operating U.S. nuclear power plants and the lessons learned through implementation of the inspections.

Introduction

In an effort to improve the effectiveness and efficiency of the U.S. Nuclear Regulatory Commission (NRC) engineering inspections within the Reactor Oversight Process (ROP), as part of the agency reform initiatives, the NRC revised the Component Design Bases Inspection (CDBI) to include inspection of licensee's implementation of key engineering areas. This change was in response to an internal NRC lessons learned report, which was performed in response to a high safety significance (Red) inspection finding at Browns Ferry. The report recommended that periodic inspection of the licensee's implementation of important engineering areas be considered as part of the ROP baseline inspection program. Nuclear industry representatives also provided feedback that the total length of the CDBI inspections took too much of their staff resources at one time to support. After extensive stakeholder engagement, NRC management decided to split the CDBI procedure into two separate inspection procedures: IP 71111.21M, “Component Design Bases Inspection (Teams),” and IP 71111.21N, “Component Design Bases Inspection (Programs),” in order to implement the lessons learned recommendation. Splitting the CDBI inspection procedure into two inspection activities performed in different years allowed a more manageable inspection program for both the NRC and the licensees. Additionally, the development of IP 71111.21N allowed the addition of periodic inspection of licensee's implementation of key engineering areas as part of the ROP baseline inspection program. Both IP 71111.21M and 71111.21N inspections are conducted on a triennial basis. The IP 71111.21N inspection areas change following the triennial cycle. The first IP 71111.21N inspection was Environmental Qualification and was conducted from January 2017 through December 2019. This paper will focus on the implementation of inspection procedure IP 71111.21N.02, “Design-Basis Capability of Power-Operated Valves Under 10 CFR 50.55a Requirements,” which began in January 2020.

1. IP 71111.21N.02 Requirements

The inspection objective is to assess the reliability, functional capability, and design basis of risk-important power-operated valves (POVs) as required by 10 CFR 50.55a and applicable 10 CFR Part 50, Appendix A and Appendix B, requirements. The process involves five key areas:

1) Sample Selection
2) Scope
3) Design
4) Testing
5) Maintenance and Corrective Actions

1.1 Sample Selection

In performing this inspection, the inspectors select a sample of POVs for detailed review of the applicable licensee activities. The inspectors may expand the sample to determine the design-basis capability of other POVs if concerns are identified with implementation of licensee activities.

In preparation for this inspection, regional inspectors should consult with subject matter experts from the NRC headquarters Division of Engineering/Mechanical Engineering and Inservice Testing Branch, along with the Regional Senior Reactor Analyst (SRA) and use risk insights to identify approximately 30 valves to consider for more detailed inspection. The inspector then request that the licensee provide design-basis capability information for those POVs including their function, safety significance, sizing and setting calculation assumptions, and operating margin. The NRC inspection team reviews the information and selects approximately 8-12 POVs for the detailed review and assessment of their operational readiness to perform their design-basis function.

1.2 Scope

Determine whether the sampled POVs are being tested and maintained in accordance with NRC regulations along with the licensee’s commitments and/or licensing bases.

1.3 Design

Determine whether the sampled POVs are capable of performing their design-basis functions.

1.4 Testing

Determine whether testing of the sampled POVs is adequate to demonstrate the capability of the POVs to perform their safety functions under design-basis conditions.

1.5 Maintenance and Corrective Actions

Evaluate maintenance activities including a walkdown of the sampled POVs (if accessible).

2. POV Inspector Training

In preparation for the implementation of inspection procedure IP 71111.21N.02 for POVs, NRC inspectors received a one and a half day training course on inspection implementation. A prerequisite for this training was successful completion of a 3-day MOV refresher course developed by the Mechanical Engineering and Inservice Testing Branch within the NRC's Office of Nuclear Reactor Regulation.

The training course material covered the following areas:

1) Regulatory requirements
2) POV design, operation, experience, lessons learned, and design-basis capability evaluation
3) POV inspection requirements, guidance, and implementation
4) POV inspection planning and logistics
5) Inspector tools

3. POV Inspection Implementation

The NRC staff began implementing POV inspections in January 2020. There were fourteen POV inspections completed in 2020. Additional POV inspections are underway in 2021 and 2022. All POV inspections will be completed by December 31, 2022.

Early communication between NRC inspectors and licensee staff was instrumental in focusing the inspection on safety significant and risk-informed valve samples. NRC Inspection Procedure (IP) 71111.21N.02 "Design-Basis Capability of Power-Operated Valves Under 10 CFR 50.55a Requirements," updated on October 9, 2020, reflect lessons learned from the first inspections implemented.

Following each POV inspection, the NRC conducts a cross-regional panel to discuss inspection items and issues. The purpose of the panels is to ensure consistency across the regions in implementation of the inspections, and consistency in dispositioning inspection findings and violations following the NRC's ROP.

3.1 COVID-19 Public Health Emergency Impacts

Many inspections were conducted partially or completely remotely due to the COVID-19 public health emergency. Effective NRC inspector and licensee communications were critical to facilitate the remote inspection efforts. Many remote inspections conducted short onsite visits to perform walkdowns, or used resident inspectors as proxies in conducting walkdowns. The inspectors successfully met the objectives of the POV inspections while conducting remote inspections.

4. Lessons Learned

4.1 Successes

Overall, the NRC has been successful in implementing the POV inspections, both in meeting the inspection objectives, and maintaining consistency in the implementation across every NRC region. This is due, in part, to the early communication with licensees and free flow of information and communication between the NRC and licensees.

4.2 Issues identified during inspections

The NRC staff identified many issues while implementing the POV inspections. Fourteen of the more repetitive or impactful findings are listed below. Each of the issues below were discussed with the applicable licensees in detail during the POV inspections. The licensees took action to address the immediate concerns related to these issues identified by the NRC inspectors. In some cases, longer term action will be needed as part of the corrective action programs at the applicable nuclear power plants. The NRC inspection reports discuss those findings that were determined to be Green, or of very low safety significance, with no findings to date. The following is a summary of the POV inspection findings to date discussed during a public meeting on December 8, 2020 (ADAMS Accession No. ML20342A041) and described in NRC Information Notice 2021-01, "Lessons Learned from U.S. Nuclear Regulatory Commission Inspections of Design-Basis Capability of Power-Operated Valves at Nuclear Power Plants," May 6, 2021.

1. The NRC inspections found that the Inservice Testing (IST) Program Plans at some nuclear power plants were not fully consistent with the American Society of Mechanical Engineers (ASME) *Operation and Maintenance of Nuclear Power Plants*, Division 1, OM Code: Section IST (OM Code) as incorporated by reference in Title 10 of the Code of Federal Regulations (10 CFR) Part 50, "Domestic licensing of production and utilization facilities," Section 55a, "Codes and standards" (10 CFR 50.55a), for POVs within the scope of the ASME OM Code. For example, some IST Program Plans for specific nuclear power plants did not address all POV safety functions. In meeting 10 CFR 50.55a(b)(3)(ii), nuclear power plant licensees may pursue risk-informed approaches based on the licensing basis including authorizations contained in the applicable ASME OM Code as incorporated by reference in 10 CFR 50.55a, and consistent with the NRC's acceptance of the implementation of the industry's Joint Owners Group (JOG) Program on Motor Operated Valve (MOV) Periodic Verification for the specific nuclear power plant. NRC inspections at some nuclear power plants found that some licensees were not periodically updating their POV risk rankings.

2. The NRC inspections found that some licensees did not address the requirement in ASME OM Code, Appendix III, "Preservice and Inservice Testing of Active Electric Motor Operated Valve Assemblies in Light Water Reactor Power Plants," to apply a mix of static and

dynamic testing. For MOVs within the scope of the JOG Program, a licensee may rely on the dynamic testing conducted as part of that program to satisfy the requirement in Appendix III for a mix of static and dynamic testing. The NRC inspections found that some licensees are installing new valves and not performing dynamic testing in accordance with ASME OM Code, Appendix III, or otherwise justifying the valve performance assumptions. The JOG Program provides guidance for re-establishing the qualifying basis for a new valve or determining the current operating valve friction coefficient for the new valve to compare to the JOG threshold value.

3. The NRC inspections found that one licensee did not follow its NRC accepted commitment modification process to modify the JOG test intervals or notify the NRC in accordance with that process. For example, the JOG Program does not include grace periods for the specified JOG test intervals. A licensee applied MOV test intervals that differed from the JOG test intervals that were relied upon by the NRC staff to close Generic Letter (GL) 96-05, "Periodic Verification of Design Basis Capability of Safety Related Motor Operated Valves," for that nuclear power plant.

4. The NRC inspections found that some licensees were not properly determining the operating requirements and actuator capability for POVs to perform their safety functions. For example, some licensees did not adequately address all appropriate parameters (such as valve friction coefficients, maximum differential pressure conditions, motor torque temperature derating factors, stem friction coefficients, and butterfly valve bearing friction coefficients) when calculating valve operating requirements or actuator capability. The NRC inspections found some licensees were using improper values for various parameters in their POV calculations (such as incorrect stem pitch and lead assumptions, valve factors and stem friction coefficients that were less than values obtained from valve tests, and incorrect uncertainty values). In some cases, licensees did not justify the use of valve friction coefficients from outside sources. The JOG Program specifies guidance for determining appropriate valve friction coefficients. In some cases, licensees did not address the potential for increased thrust and torque requirements (referred to as side loading) to operate globe valves under high flow dynamic conditions. In some cases, licensees did not consider the presence of radiation hot spots and ambient temperature conditions that can impact the service life of environmental qualification of a valve actuator. The NRC inspections found one licensee had not updated its POV program to incorporate new computer software used in its POV calculations. The NRC inspections found that the capability of individual POV subparts was not determined to be able to withstand the maximum thrust and torque that the POV actuator can produce (sometimes referred to as a weak link evaluation). For example, structural limits specified in the ASME *Boiler and Pressure Vessel Code* are not applicable to POV internal parts that involve operating motion of the valve and actuator. With respect to previous POV capability issues, GL 79-46, "Containment Purging and Venting During Normal Operation Guidelines for Valve Operability," dated September 27, 1979 (ADAMS Accession No. ML031320191), provides recommendations to demonstrate that containment purge valves can close and seal under design basis conditions, including seismic loads.

5. The NRC inspections found that some licensees incorrectly assumed that the valve friction coefficients determined for MOVs as part of the JOG Program represented a database of friction coefficients that can be applied in general to calculate the thrust and torque required to operate various MOVs under design basis conditions. The JOG Program determined whether there was the potential for degradation of valve friction coefficients for various valve types and applications, rather than determining specific values of friction coefficients. The

NRC provided information on various approaches for obtaining valve performance data in IN 2012-14, “Motor Operated Valve Inoperable Due to Stem Disc Separation,” dated July 24, 2012 (ADAMS Accession No. ML12150A046).

6. The NRC inspections found that contrary to the industry topical report MPR 2524A on the JOG Program on MOV Periodic Verification, some licensees who committed to the JOG Program to satisfy GL 96-05 and are implementing the JOG Program as part of their compliance with 10 CFR 50.55a(b)(3)(ii) had not established methods to periodically demonstrate the design basis capability of their MOVs that are JOG Class D valves (defined by JOG as outside the scope of the JOG Program). In addition, the NRC inspections found that some licensees had modified the JOG classification of their MOVs from a JOG Class D valve to a JOG Class A valve (defined by JOG as not susceptible to degradation). The basis for reclassifying a valve that is outside the scope of the JOG Program (JOG Class D valve) to a valve not susceptible to degradation (JOG Class A valve) was not apparent. The NRC inspections also found that some licensees were applying guidance developed by the Electric Power Research Institute (EPRI) for evaluating MOV diagnostic test data obtained under static conditions (i.e., without differential pressure or flow) beyond the capability of that testing to predict MOV performance under dynamic conditions (i.e., differential pressure and flow).

7. The NRC inspections found that some licensees that evaluated MOVs using the EPRI MOV Performance Prediction Methodology (PPM) were not addressing all of the applicable provisions when implementing the EPRI MOV PPM to determine valve operating requirements. In accepting the EPRI MOV PPM, the NRC staff noted that EPRI assumed that each valve is maintained in good condition for the EPRI MOV PPM to remain valid for that valve. The NRC inspections found that some licensees were incorrectly assuming that a valve is JOG Class A or JOG Class B (defined by JOG as not susceptible to degradation by extension) because the EPRI PPM was applied without ensuring that the valve is maintained with good internal condition. The NRC provides more information on the EPRI MOV PPM in NUREG-1482, “Guidelines for Inservice Testing at Nuclear Power Plants,” Revision 3, issued July 2020 (ADAMS Accession No. ML20202A473).

8. The NRC inspections identified an instance of improper justification for increasing the thrust ratings for certain Limitorque motor actuators beyond their qualified design limits. Limitorque Technical Update 92-01, “Thrust Rating Increase SMB-000, SMB-00, SMB-0 & SMB-1 Actuators” (which is available from Limitorque), evaluated Kalsi Engineering Document #1707C (which is a proprietary report by Kalsi Engineering) and approved its use to increase the maximum allowable thrust for Limitorque actuator models SMB-000, SMB-00, SMB-0, and SMB-1 up to 140 percent of the original ratings, with certain conditions. The 140 percent maximum thrust that Limitorque allows in Technical Update 92-01 is less than the 162 percent maximum thrust limit discussed in Kalsi Engineering Document #1707C. Despite the limitations of the Limitorque analyses, NRC inspections found some licensees had applied Kalsi Engineering Document #1707C to increase the allowable maximum thrust for Limitorque actuators to 162 percent of the original ratings. Previously, licensees had to have specific permission from Limitorque to increase the allowable maximum thrust for Limitorque actuators to 162 percent of the original ratings. Limitorque has since indicated that licensees that participated in the Kalsi study or have possession of the proprietary Kalsi Engineering Document #1707C report may apply the 162 percent maximum thrust rating described in the Kalsi report where the specific conditions are implemented without an individual letter from Limitorque.

9. The NRC inspections at some nuclear power plants identified that POV testing was not conducted properly, and the results were not adequately evaluated to demonstrate that the POVs could perform their safety functions. For example, POV test acceptance criteria were not properly translated from POV design calculations to test procedures. Diagnostic equipment was not verified to be installed and operating properly as part of the POV testing and evaluation of results. Operating requirements for valves were not evaluated throughout the full valve stroke. POV test data evaluations were not fully completed to ensure that the required parameters (such as valve friction coefficient, stem factor, and rate of loading) were being calculated and that they were within the acceptable range. Valve friction values from testing were not compared to the JOG threshold values for valve friction when implementing the JOG Program. Overthrust events when testing POVs were not addressed. The potential variation of valve performance was not addressed when relying on a single test to establish POV operating requirements. Licensees relying on the use of POV static testing associated with containment leakage testing in accordance with 10 CFR Part 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water Cooled Power Reactors," are responsible for justifying when using such testing to demonstrate that the requirements of 10 CFR 50.55a(b)(3)(ii) for periodic verification of MOV design basis capability are satisfied. The NRC inspections found that the performance of thermal overload devices that can impact the safety function of MOVs was not evaluated periodically. The NRC inspections also found that monitoring reports were not prepared in accordance with plant procedures to identify any adverse performance indications of POVs.

10. The NRC inspections found that some licensees, with MOVs that had a safety function to close, had set the motor control switch trip circuit to be controlled by the limit switch gear train, instead of the torque switch. For example, some licensees were relying on static testing of limit switch controlled MOVs performed as part of containment leakage testing in accordance with 10 CFR Part 50, Appendix J, in their effort to meet the 10 CFR 50.55a(b)(3)(ii) requirement for periodic verification of MOV design basis capability. Although the MOVs are required to close and seal under dynamic conditions, some licensees set those MOVs using the limit switch during a periodic static test. The NRC inspections identified that some licensees did not have a valid test or analysis demonstrating that the limit switch control setting of the MOV under static conditions will achieve the required leak tight performance when the MOV is closed under dynamic conditions.

11. The NRC inspections identified that some licensees did not provide adequate justification to extend the qualified life of POVs installed in their nuclear power plants. Limitorque qualified its safety-related MOV actuators for 40 years or 2,000 cycles, whichever comes first. Licensees are permitted to extend the qualified life of their Limitorque actuators if they have adequate justification. The justification for the extension of the qualified life of the actuator, including attention to radiation levels and ambient temperature conditions where MOVs are located, should provide assurance that the environmental qualification requirements are not exceeded, and that appropriate replacement frequencies for POVs or their individual parts are established. EPRI has developed guidance for extending the qualified life of Limitorque actuators that includes provisions for a valve assembly that is considered to be functional beyond its qualified life. Licensees may follow this guidance or choose their own method where justified.

12. The NRC inspections found that some licensees were not properly implementing the Boiling Water Reactor Owners Group (BWROG) guidance (such as evaluating the weak link of the wedge pin under motor stall conditions) in assessing the susceptibility for separation of the stem disk connection in Anchor/Darling double-disk gate valves. This guidance was

established by the BWROG to address the issue of potential failure of the stem disk connection in Anchor/Darling double disk gate valves, which is discussed in IN 2017-03, "Anchor/Darling Double Disc Gate Valve Wedge Pin and Stem Disc Separation Failures," dated June 15, 2017 (ADAMS Accession No. ML17153A053).

13. The NRC inspections found that some licensees were not meeting the requirement in 10 CFR 50.55a(b)(3)(xi) to supplement the valve position indication testing required in paragraph ISTC-3700, "Position Verification Testing," in Subsection ISTC, "Inservice Testing of Valves in Water Cooled Reactor Nuclear Power Plants," of the 2012 Edition and later editions of the ASME OM Code. Paragraph ISTC 3700 requires, as conditioned by 10 CFR 50.55a(b)(3)(xi), that valves with remote position indicators be observed locally at least once every 2 years to verify that valve operation is accurately indicated. The NRC regulations in 10 CFR 50.55a(b)(3)(xi) state that when implementing ASME OM Code, 2012 Edition (or later editions), paragraph ISTC 3700, licensees shall verify that valve operation is accurately indicated by supplementing valve position indicating lights with other indications, such as flow meters or other suitable instrumentation, to provide assurance of proper obturator position. In the July 18, 2017, *Federal Register* notice (82 FR 32934) for the final rule, the NRC emphasizes the provisions in the ASME OM Code, 2012 Edition, paragraph ISTC-3700, requiring verification that valve obturator position is accurately indicated, and does not state or indicate that the condition in 10 CFR 50.55a(b)(3)(xi) represents a new test. In particular, paragraph ISTC-3700 requires licensees to test valves every 2 years to verify their remote position indicating lights. The NRC responses to public comments on the proposed rule (ADAMS Accession No. ML16130A531) included a response to a specific public comment requesting an additional 24 months to implement 10 CFR 50.55a(b)(3)(xi) for licensees nearing their IST Program update deadline. The NRC response stated that licensees would not be allowed additional time to comply with this condition as part of the rulemaking, and that licensees determining that they will need additional time to implement the 2012 Edition of the ASME OM Code (including the condition on valve position indication in 10 CFR 50.55a(b)(3)(xi)) may submit a request for an alternative in accordance with 10 CFR 50.55a(z) for NRC staff review. Additional information on this topic is found in two monthly ROP meeting summaries (ADAMS Accession Nos. ML21041A409 and ML21047A290).

14. With respect to POV preventive maintenance and walkdowns, the NRC inspections found that some licensees were not justifying the lubrication interval for the MOV stem where brittle or degraded lubrication grease was identified that could have impacted the operation of the MOV. The NRC inspections found MOVs installed in non-normal positions that can cause MOV maintenance issues (such as potential grease leakage into the limit switch compartment that might lead to grease interfering with the actuator wiring, or abnormal performance of a gate valve with the disk in the horizontal plane resulting in increased wear over time).

5. Conclusion

NRC engineering inspections play an important role in the ROP. They enable the NRC to verify safety system capability under accident conditions that do not reveal themselves through testing or plant operation. The POV inspections are important to assess the reliability, functional capability, and design-basis capability of risk-important POVs to determine whether licensees are maintaining the POV capability to perform as intended under design-basis conditions.

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MOVs (Mandatory Appendix III)

Track Chair: Domingo Cruz, APS/Palo Verde Generating Station

Eliminating Fluttering and Related Damage in Large Butterfly Valves

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Abstract

Large butterfly valves in condenser inlet lines of the circulating water system have experienced excessive disc-flutter related problems in several nuclear plants for many years. Excessive disc flutter has caused drift in the disc position and failure of valve, actuator, and quarter-turn gearbox components requiring unscheduled maintenance and/or replacement of components causing loss of revenue. Plants have historically addressed these problems caused due to fluttering by strengthening the failed components that result in shifting the weak-link to the next weakest component in the load-carrying components. In general, these attempts have not been successful in addressing the root cause of the problem nor in eliminating unscheduled plant maintenance.

A systematic approach has been developed by Kalsi Engineering, Inc. (KEI) to address the excessive butterfly valve fluttering and associated problems. The approach utilizes strain-gauge data measured on the valve, advanced computational fluid dynamics (CFD) analyses, and structural/fatigue analyses to provide a long-term solution that eliminates the unexpected failures and unscheduled plant maintenance.

In the past two decades, KEI has performed a large matrix of testing and CFD analyses on different butterfly valve disc shapes. The data gathered through this effort has significantly helped in providing recommendations for changing the disc orientation/position to minimize the fluttering when CFD and plant test data is not available. The KEI test data have also helped making judicial selections of the disc positions to be analyzed by CFD methods.

This paper presents applications of this systematic approach that resulted in a successful long-term solution. The recommendations based on this approach have eliminated the chronic fluttering related problems at a nuclear plant. The plant was able to use the analytical predictions to set suitable maintenance/replacement schedule.

1. Introduction

Fluttering in butterfly valves occur due to fluctuating disc hydrodynamic torque caused by fluid turbulence. Fluid turbulence and hence fluttering is practically present in most of the butterfly valves. But a severe turbulence causes excessive fluttering and can result in disc hydrodynamic torque reversals. Torque reversals cause valve/actuator torque-train components to accelerate within the mating clearances and impact with each other. The inertial loads from the impact greatly increases the torque transmitted to the components causing premature failure.

A typical butterfly valve installation is shown in Figure 1. The butterfly valve shaft is connected to quarter-turn gearbox via the keyed splined adapter. Butterfly valve fluttering in nuclear power plants has caused structural/fatigue failures of the torque-carrying components of the valve, gearbox, and the actuator due to fatigue failure as shown in Figure 2. Unscheduled component replacement can cause loss of plant power output; therefore, it is highly desirable to reduce/minimize the valve fluttering.

Frequent torque reversals also cause a drift in the disc position because torque reversal results in a momentary loss of the friction at the mating surfaces of the torque-train components. The loss of friction allows the valve disc to drift based on the direction of the time-averaged hydrodynamic torque. If the disc drifts to a smaller opening angle, it reduces the flow through the valve and can affect the plant power output. In such cases, plant personnel have to monitor and adjust the valve disc open angle.

Note that the disc fluttering can occur in butterfly valves of any size. But the structural damage due to fluttering is more pronounced in the large butterfly valves because of the associated larger inertia of the moving components.

To prevent torque reversals and fluttering-induced impact torque transmitted to the torque train, the time-averaged hydrodynamic torque should exceed the hydrodynamic torque fluctuation amplitude by sufficient margin.

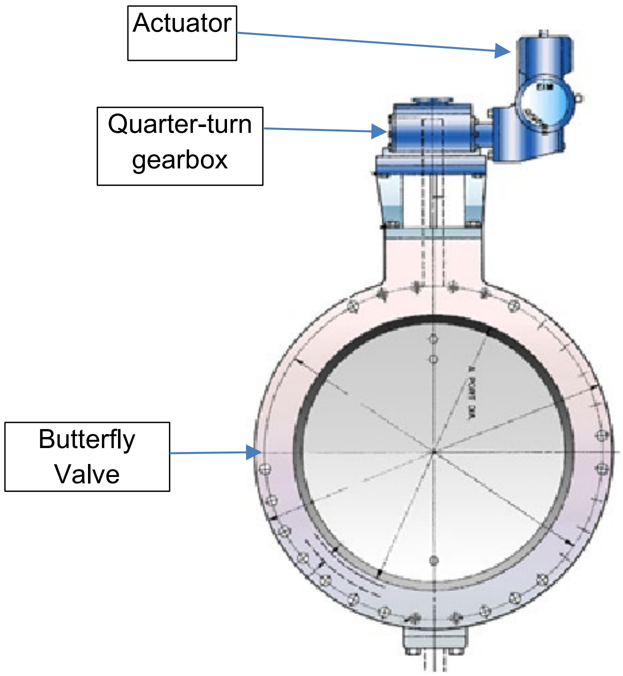

Figure 1: BUTTERFLY VALVE WITH A QUARTER-TURN GEARBOX AND A MOTOR ACTUATOR

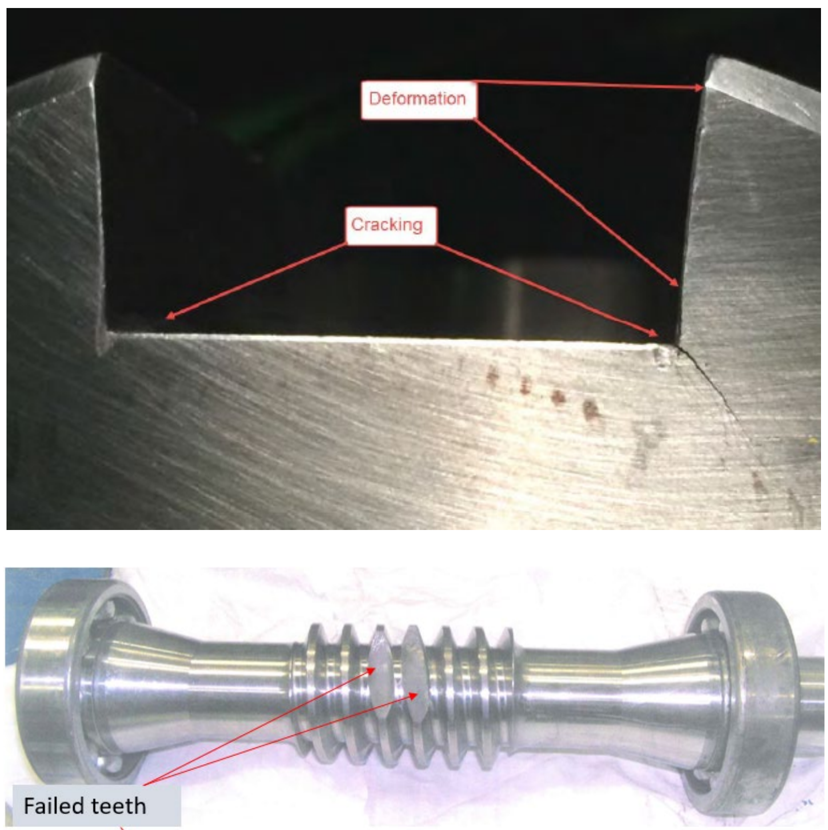

Figure 2: EXAMPLES OF VALVE/ACTUATOR COMPONENT FAILURE DUE TO FLUTTERING

2. Materials and Methods

The systematic approach developed by KEI consists of the following steps:

(1) Review the valve and system in which it is installed. Specifically, review the disc shape/offset, and the disturbances like elbow, reducers, bends. upstream of the valve in the plant.

(2) Use insights from KEI's database of flow loop testing and CFD analyses for possible success paths.

(3) Review the available torque measurements obtained on the valve for different disc positions.

(4) Perform CFD analyses to obtain disc hydrodynamic torque time-history for judicially-selected valve disc positions/orientations.

(5) Perform structural strength and fatigue analysis of the key torque-train components to calculate margin against failure.

(6) Provide recommendation to reduce/eliminate the disc fluttering based on the overall analyses results.

Suitable changes are made in this approach for different plants to conform to the practical constraints like the availability of torque measurements, CFD solution run-times, and project schedule.

2.1 Review KEI flow-loop test data relevant to the valve system

Butterfly valve discs are manufactured with a variety of symmetries (symmetric, non-symmetric), disc aspect ratios, disc offsets (single-, double- and triple-offset), and disc face geometry (flat, curved) and solid/flow-through discs. Furthermore, the valves can be installed in different shaft orientations with respect to flow (shaft-upstream, shaft-downstream), upstream elbow configurations (disc shaft within or perpendicular to the upstream elbow plane), with different upstream disturbances (elbows, bends, reducers etc.) and different upstream disturbance proximities. All these factors affect the disc hydrodynamic torque to a different extent [7].

Over the last 20 years, KEI has performed a large matrix of tests and CFD analyses on a judicially-selected combinations of the above parameters with compressible/incompressible flow, different flow velocities, and pressure ratios at different disc opening angles [4]. Figure 5 shows CFD analysis results for different upstream elbow proximity. A brief overview of the different tests performed by KEI is given below:

- Disc shape: symmetric, non-symmetric (see Figure 3)
- Disc aspect ratio: 0.15 to 0.31 (symmetric), 0.09 to 0.47 (non-symmetric)
- Disc front face geometry: Flat or recessed. The recess can be flat or concave.
- Disc shaft side geometry: Prismatic, conical or radiused
- Shaft orientations for un-symmetric disc: shaft-upstream, shaft-downstream
- Upstream disturbance: Tee, elbows, bends
- Upstream elbow configuration: disc shaft within or perpendicular to the upstream elbow plane (See Figure 4)
- Upstream elbow type: short/large-radius, miter elbow

Many of these test results have been incorporated in Kalsi Valve & Actuator Program (KVAP) [5][6]. KVAP is a state-of-the-art software based on first principles models and extensive 10 CFR Part 50, Appendix B, testing for performing design-basis calculations for all common linear and quarter-turn AOVs and MOVs in the industry.

KEI flow-loop test data for the valve-system combination closest to the actual plant application is reviewed to understand the effects of the flow velocity, disc opening angle, and disc configurations on the valve hydrodynamic torque. Comparison of a given disc tested under different shaft orientations and piping configurations helps KEI identify the shaft orientation having high potential to minimize disc fluttering. The test data also helps in judicial selection of disc positions/orientations to be assessed using CFD analyses for minimizing the valve fluttering; thereby, minimizing the number of CFD analyses to be performed.

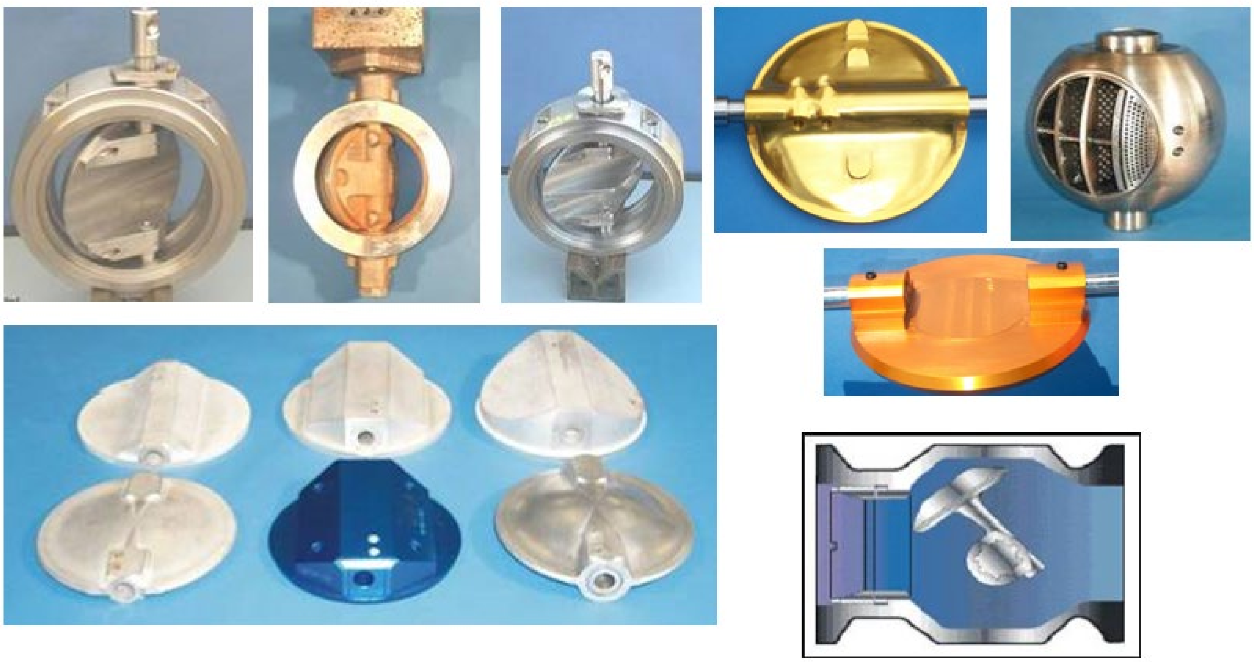

Figure 3: FLOW LOOP TESTS PERFORMED BY KEI ON COMMONLY USED DISC SHAPES

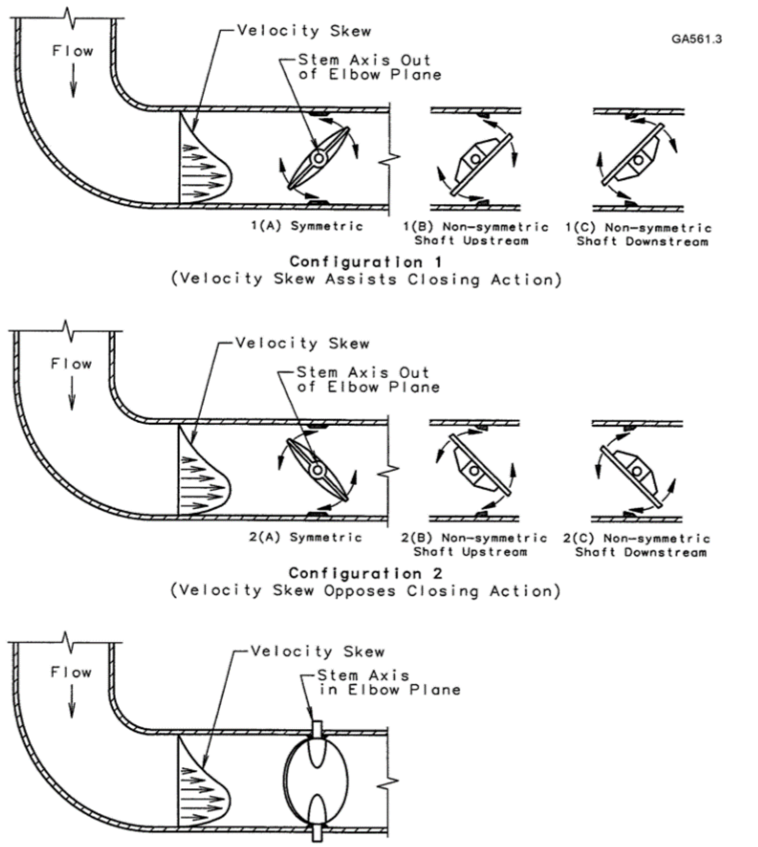

Figure 4: DIFFERENT VALVE DISC ORIENTATIONS WITH RESPECT TO AN UPSTREAM ELBOW

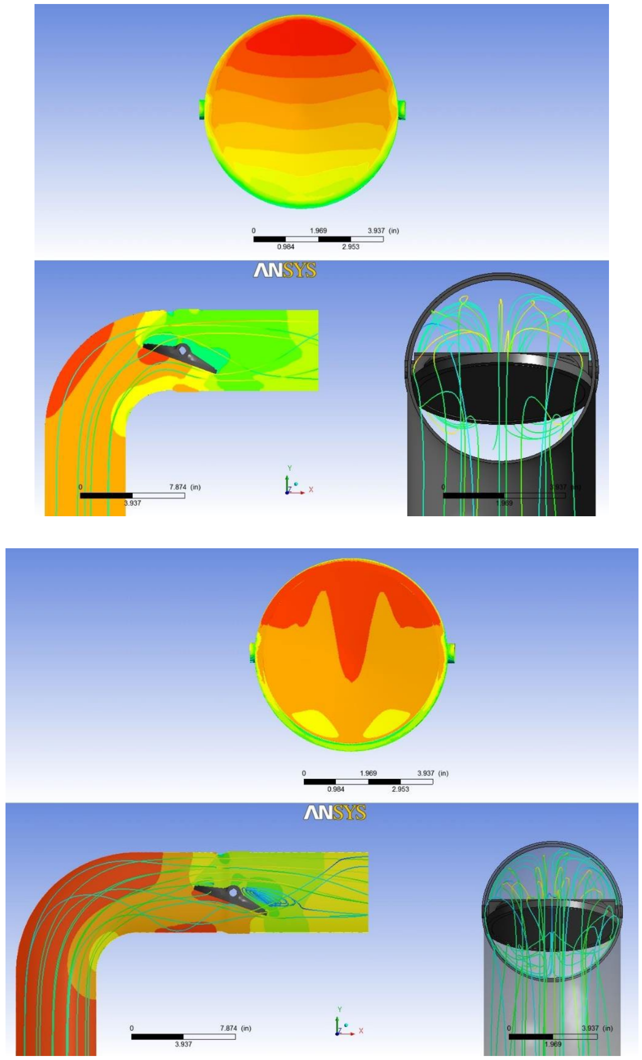

Figure 5: CFD ANALYSES PERFORMED BY KEI ON BUTTERFLY VALVE DISCS WITH DIFFERENT UPSTREAM ELBOW PROXIMITIES. TOP IMAGE: ELBOW AT 0D, BOTTOM IMAGE: ELBOW AT 1D (D = PIPE DIAMETER)

2.2 Review torque measurements from the plant

The torque measurements obtained on the valve experiencing fluttering under the plant flow conditions are immensely helpful to understand the relationship between disc open angle and disc flutter. Analysis of torque measurements can help identify which disc positions are more prone to flutter, and which are not. Quite often smaller disc open angles exhibit lower amplitude flutter than those at larger disc open angles. However, setting the valve at a smaller disc position can significantly reduce the flow rate through the valve, which can result in loss of plant power generation capacity.

Although having the plant-based torque data is of great value, obtaining the torque data is not always practical. Additionally, the torque data can only be obtained in the existing disc configuration and not for other disc configurations like by flipping the shaft orientation (upstream to downstream or vice versa) and for a disc rotated about the pipe axis. In such cases, advanced CFD analyses can provide accurate hydrodynamic torque time-history for the valve under different disc configurations/orientations.

2.3 Perform advanced CFD analyses

CFD analyses can be utilized to calculate disc hydrodynamic torque time-history for different disc configurations/orientations.

Selection of a turbulence model is one of the key inputs affecting accuracy of the CFD solution. approach to predicting turbulent flows is to use the Reynolds Averaged Navier-Stokes (RANS) equations, which solve for time-averaged quantities. Using the averaged quantities simplifies the calculations, but may not accurately resolve the flow field and accurately model fluid pressure fluctuations and vortex shedding. Advanced simulations like Large Eddy Simulation (LES), Detached Eddy Simulation (DES), Stress-Blended Eddy Simulation (SBES), and Scale-Adaptive Simulation (SAS) can provide more accurate results for such problems. Details of these models are available in Reference [2]. Depending on the nature of the problem, an appropriate model is used to calculate hydrodynamic torque time-history for different disc positions and pipe configurations. Comparison of these torque time-histories helps determining the disc positions and shaft orientations that would reduce/minimize the fluttering.

2.4 Perform structural/fatigue analyses

The disc positions/orientations that would minimize the fluttering without significantly reducing flow through the valve are determined using the torque measurements obtained in the plant and/or CFD analyses results. Structural/fatigue analyses are performed to ensure sufficient positive margin against failure for the torque carrying components at these disc positions/orientations. The stress analysis required for the structural/fatigue analysis can be performed using first principles and/or Finite Element Analysis (FEA). Additionally, KEI-developed worm and worm-gear structural strength and failure models that have been validated through laboratory testing can be utilized for strength/failure analysis of some of the torque-train components.

The highly fluctuating nature of the torque transmitted to torque-train components makes fatigue analysis challenging from the point of calculating the alternating load amplitudes and the load cycles. KEI developed a computer program to quickly and accurately calculate the amplitudes of fluctuating torque from the fluctuating torque time history using a cycle counting algorithm [3]. The computer program reads in the torque time-history and calculates the mean and amplitude values for the torque cycles within the torque history. Additionally, the program accepts user input to convert the torque to stress and using equation for the fatigue curve it directly outputs the fatigue life for the specific component for the given torque history.

A thorough review of the results from the above analyses is performed. The disc position/orientation that would minimize the disc fluttering and would provide sufficient positive margin against structural/fatigue failure is recommended to the plant to minimize/eliminate fluttering.

3. Results and Discussion

The methodology presented here has been successfully applied to different plants and the details are discussed below.

3.1 84-inch single-offset butterfly valve at STP

The condenser inlet valves in the circulation water system at South Texas Project (STP) nuclear plant had been experiencing fluttering for many years (see Figure 6). The valves are 84-inch single-offset butterfly valves installed with an upstream shaft.

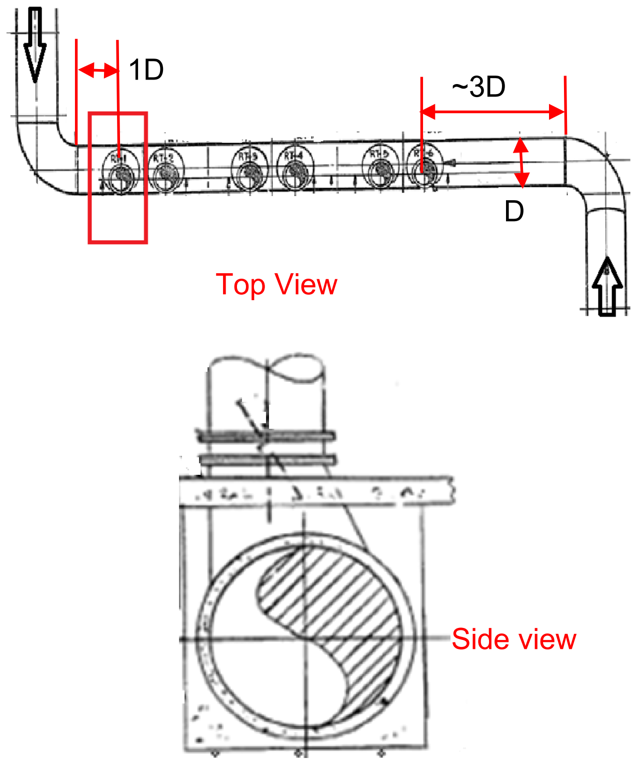

Figure 6: CIRCULATING WATER SYSTEM AT STP. WATER FLOWS FROM BOTH THE ENDS AND PASS THROUGH THE SIX BUTTERFLY VALVES (TOP IMAGE). EACH VALVE HAS AN ECCENTRIC REDUCER JUST UPSTREAM (BOTTOM IMAGE).

As shown in the top image in Figure 6, water flows in from both sides of the header towards the valves and flows out through the six valves. The first valve on the left side (highlighted by a red box) had been experiencing excessive fluttering. Review of the first valve installation showed that the valve has an upstream elbow within 1 pipe diameter and an eccentric reducer just upstream of the valve. The flow makes two right angle turns: first in the upstream elbow and then in the eccentric reducer. The two 90° turns result in a large velocity skew, swirl and flow separation causing vortex shedding in the eccentric reducer. The other valves are farther away from the upstream elbow and have lower inlet velocities and, therefore, would experience less velocity skew and swirl compared to the first valve. This has been confirmed from the CFD analyses for a similar system in which the common header and 6 pipe outlets were analyzed.

Figure 7 shows the torque time-history recorded by the plant for a disc position the plant had set. It can be seen that the fluttering-induced impact results in a significantly larger torque compared to the normal operating torque levels.

The plant had obtained torque measurements on these valves at different disc opening angles during system operation. The torque measurements were reviewed, and structural strength calculations were performed using first-principles and FEA. The fatigue analyses were performed using a computer program described in Section 2.4 of this paper. The torque time-history in Figure 7 converted to fluctuating and mean values using the cycle counting algorithm is shown in Figure 8.

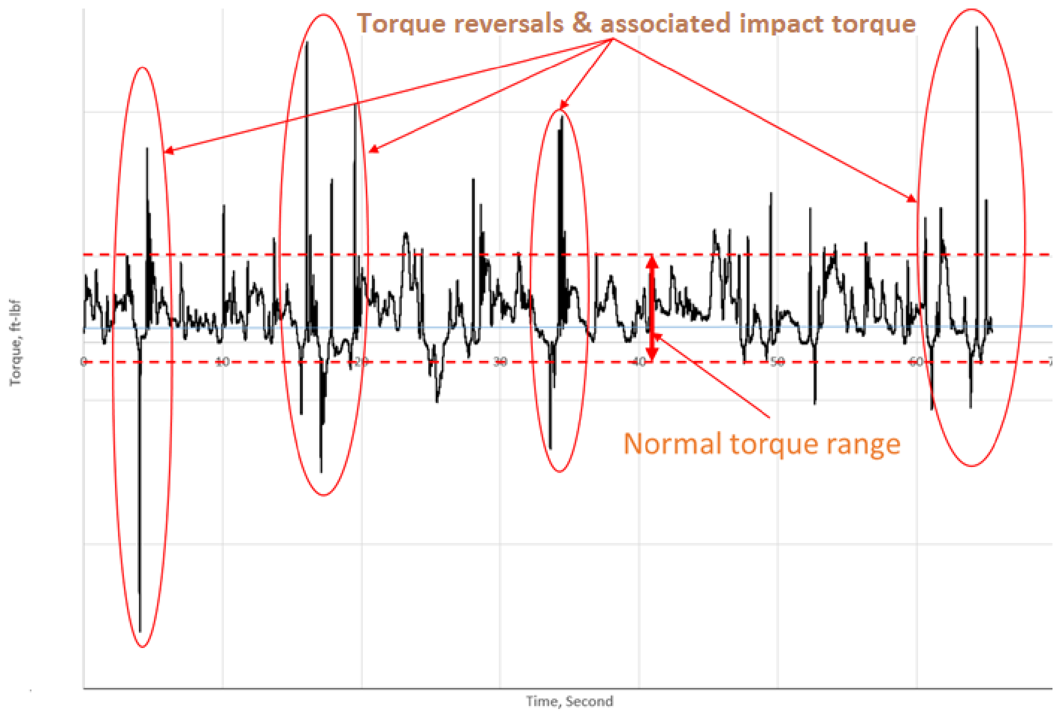

Figure 7: FLUTTERING-INDUCED IMPACT TORQUE

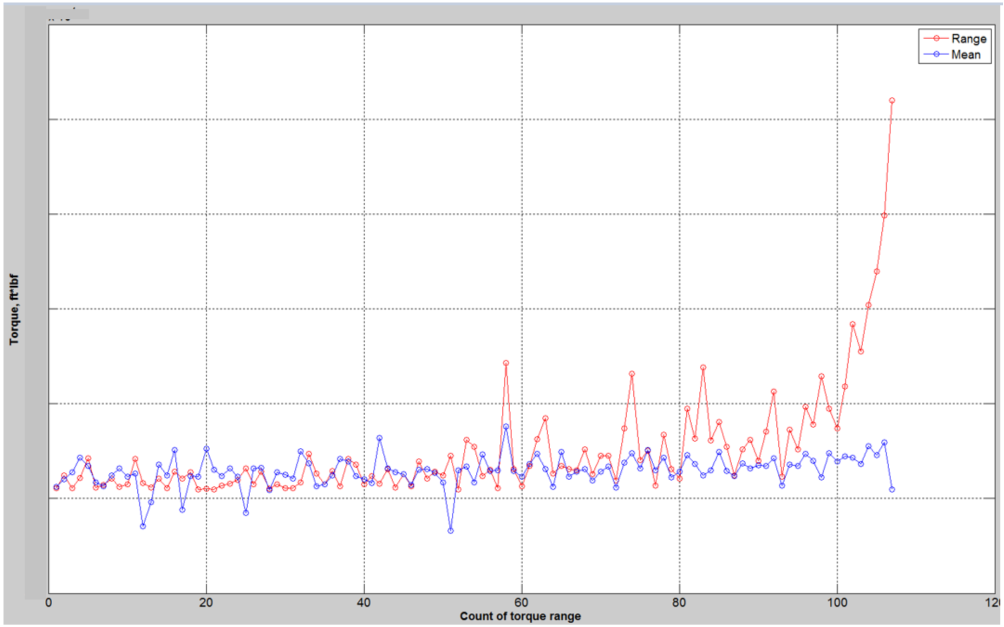

Figure 8: RANGE/MEAN TORQUE VALUES OBTAINED USING RAINFLOW ALGORITHM FOR THE TORQUE HISTORY SHOWN IN Figure 7 (NOTE: RANGE = 2*AMPLITUDE)

From these results, it was concluded that reducing the disc open angle by 10-15% would significantly minimize the disc fluttering and would provide adequate margin against static/fatigue loads. The plant implemented KEI recommendation, and no excessive fluttering was observed in the valve during several months of valve monitoring. The plant observed practically no loss of condenser efficiency and plant power output due to reducing the disc open angle.

3.2 84-inch symmetric-disc butterfly valve

A 3-dimensional model of the circulating water tunnel from another nuclear plant is shown in Figure 9. There are four additional vertical branches downstream of the two branches shown in Figure 9 (total six branches with one valve in each branch). As indicated on Figure 9, water flows through two 90° bends, first 90° left turn from tunnel to the horizontal path leading to vertical pipe and then vertically 90° to the pipe. The bends have internal facets and have abrupt cross-sectional changes. The valve is located just downstream of the second bend (see Figure 9).

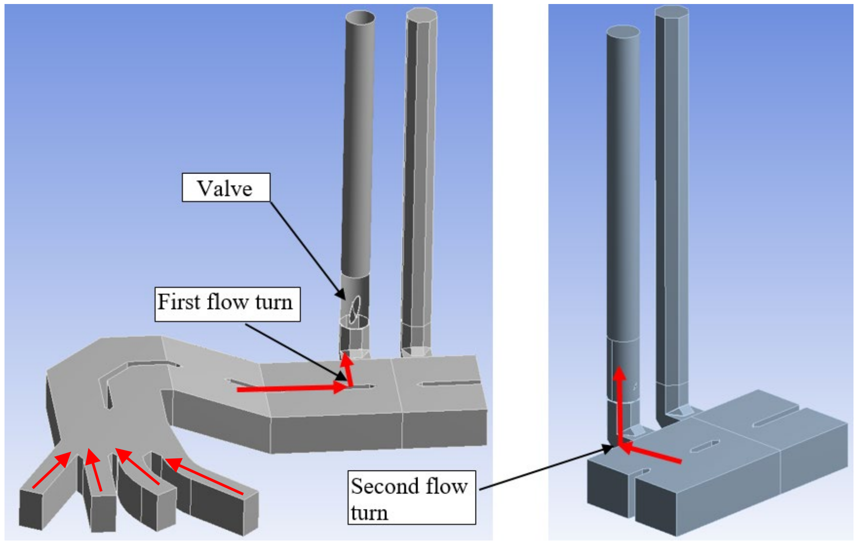

Figure 9: CIRCULATING WATER SYSTEM AT A NUCLEAR PLANT

Due to plant schedule constraints, torque measurements could not be obtained at the beginning of the project. Therefore, CFD analyses were performed at different disc positions/orientations to obtain fluctuating torque time-history.

CFD analyses results shown in Figure 10 confirmed that the bends caused a large velocity skew and swirl. Additionally, the results showed that the sharp facets caused vortex shedding. The large vortices and fluctuating velocity swirl was concluded to have caused large amplitude disc flutter for the valve in the first branch shown in Figure 9. The velocity skew/swirl in the second branch was found to be much lower compared to the first branch. These conclusions from the CFD analyses results corroborated well with the plant experience of excessive fluttering only in the valve located in the first branch.

Based on the CFD-predicted flow impingement location on the disc, the disc-flow interaction is closer to elbow configuration 1(A) (velocity skew assists closing) shown in Figure 4 [4].

Therefore, KEI's proprietary test data for a symmetric disc butterfly valve having an aspect ratio close to that of the subject valve disc tested under configuration 1(A) were reviewed. Based on this review, it was concluded that setting the valve at a smaller disc open position would tend to reduce the torque reversal magnitudes. CFD results for different disc positions in the existing disc configuration were performed to determine the range of disc open angles associated with lower amplitude torque fluctuations compared to the current disc position.

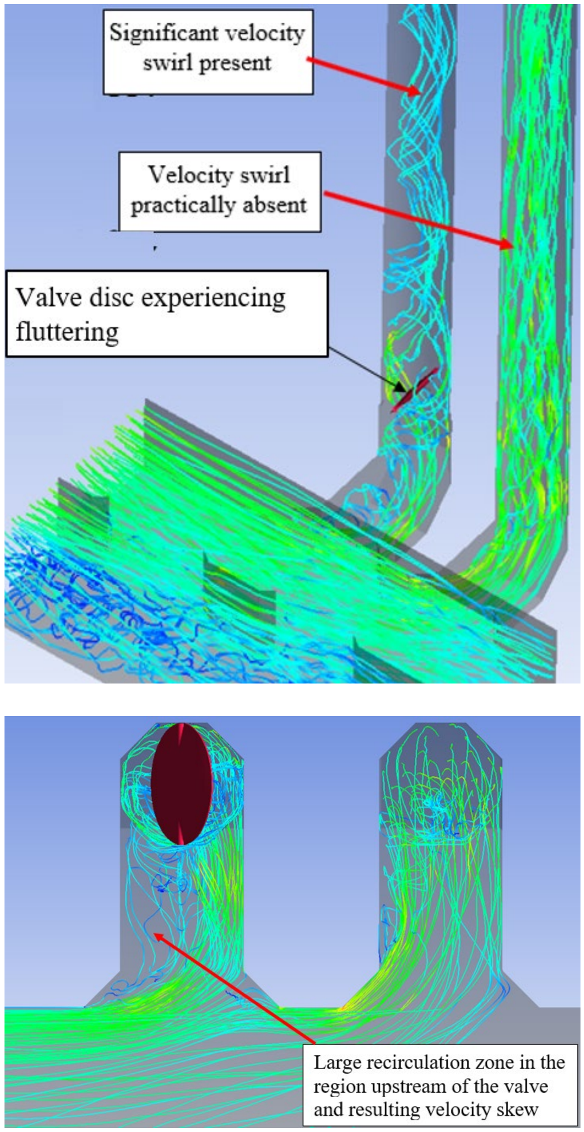

Figure 10: CFD ANALYSIS RESULT SHOWING VELOCITY SWIRL (TOP IMAGE) AND VELOCITY SKEW (BOTTOM IMAGE)

Fatigue life calculations were performed on a component failed due to fatigue in the past and it showed good corroboration between the calculated and actual life. Structural strength and fatigue analyses performed using the torque time-history obtained from CFD showed sufficient positive margin against failure for the recommended disc position. Figure 11 shows the stresses in the splined adapter due to applied torque load.

Based on the CFD and structural analyses results, a disc position that showed lower amplitude torque fluctuations and sufficient margin for the torque train components was recommended to the plant. System resistance calculations showed that the recommended disc opening angle would cause insignificant change in the flow rate through the valve and, therefore, would not affect the condenser efficiency. The plant will be implementing these changes in the forthcoming scheduled outage and would monitor the valve fluttering performance post-modifications.

4. Conclusions

The systematic technical approach developed by KEI is flexible to utilize the torque measurements and/or CFD analyses results depending on the availability of the measurement data, project budget, and schedule. The KEI butterfly valve test data offers significant advantage in providing recommendations for changing the disc orientation/position to minimize the fluttering when CFD results and plant test data are not available. The KEI test data also helps making judicial selections of the disc positions to be analyzed by CFD methods. Results from the advanced CFD analyses performed by KEI has shown good corroboration with the plant observations for disc fluttering. The structural analyses were performed using first principles strength of materials and FEA depending on the complexity of the component geometry and loading. The KEI-developed computer program efficiently calculates fatigue cycles (and additionally design fatigue life) from a complex torque time-history.

Based on this approach, the predicted fatigue life of a component failed in the past matched reasonably well with its actual life. The recommendations provided using the systematic technical approach presented here successfully eliminated the excessive fluttering problems at STP nuclear plant.

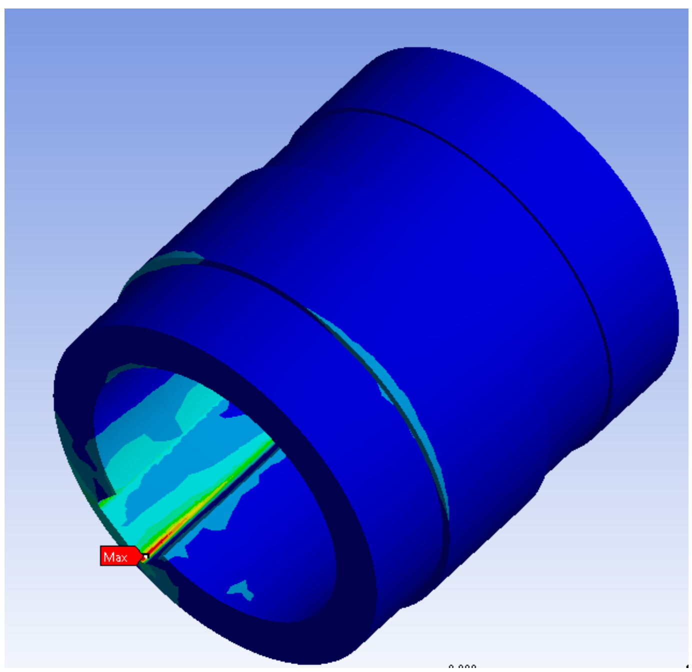

Figure 11: STRESSES IN THE SPLINED ADAPTER DUE TO APPLIED TORQUE LOAD

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Comparison of EPRI PPM to Vendor Sizing for Active Motor Operated Valves at an AP*1000*® Plant

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Abstract

The design specifications for the safety-related motor operated valves (MOVs) in the AP1000[i] plant require the selected valve vendor to meet the requirements of American Society of Mechanical Engineers (ASME) Standard QME-1-2007, "Qualification of Active Mechanical Equipment Used in Nuclear Power Plants." Paragraph QV-7463.3(c)(2) of this standard requires that the valve vendor "Verify applicability of the stem-to-stem-nut coefficient of friction and the load sensitive behavior of the production valve assembly to the qualified valve assembly through the use of specific test data or a test-based qualification methodology" for each production rising-stem MOV qualified to the standard. The test-based qualification methodology referred to is the Electric Power Research Institute (EPRI) MOV Performance Prediction Methodology (PPM).

In the initial development of the motor sizing for the active safety-related MOVs in AP1000 plants, the selected valve vendor utilized design requirements explicitly called out in the design specification to establish the size of the motor operators needed. Some of these requirements include limiting the available material choices of mating parts (e.g., disc/seats, disc/guides) to those materials covered by the Joint Owner's Group report MPR-2524-A, "Joint Owner's Group (JOG) Motor Operated Valve Periodic Verification Program Summary," using a minimum stem coefficient of friction of 0.20, and requiring minimum uncertainties for load sensitive behavior (LSB also referred to as rate of loading (ROL)) of 5.6% bias and 26.4% random uncertainty, among others. However, without access to facilities with the capabilities to perform dynamic flow testing of these valves under design basis (or as near as practicable to design basis) conditions, the valve vendor was unable to confirm that all of these design requirements, as suggested in the design specification, bound the actual characteristics of each production valve, prior to shipping the valve to site for installation.

To expedite construction activities and reduce overall construction costs, a U.S. utility currently constructing an AP1000 plant elected to have Westinghouse Electric Company execute the EPRI PPM, where applicable, for the active motor-operated gate and globe valves to establish the minimum required thrust (MRT) to open or close the valve. Using this methodology to establish the MRT is in compliance with the ASME QME-1 Standard and allows the utility to satisfy their Inspection, Test, Analyses, and Acceptance Criteria Commitments. This paper will provide a background of the active safety-related MOVs at this nuclear plant, summarize the methodology used by the valve vendor to ascertain the MRT, summarize the methods used to establish the MRT using the EPRI PPM, as well as compare of the MRT established by the valve vendor to the MRT established using EPRI PPM. This comparison will show how, in some cases, vendor methods can be insufficient to establish a sufficiently conservative MRT.

Correspondingly, the comparison will show how vendor methods can be overly conservative predictions of MRT, allowing for significant margin recapture by the program owner.

Nomenclature

The following nomenclature is used throughout this paper:

COF	Coefficient of Friction
CVCS	Chemical and Volume Control System
DC	Direct Current
EPRI	Electric Power Research Institute
INEL	Idaho National Engineering Laboratory
JOG	Joint Owners' Group
LSB	Load Sensitive Behavior
MRT	Minimum Required Thrust
NMAC	Nuclear Maintenance Application Center
NRC	U.S. Nuclear Regulatory Commission
PPM	Performance Prediction Methodology
RHR	Residual Heat Removal System
ROL	Rate of Loading
SI	Safety Injection
SRSS	Square Root Sum of Squares
U.S.	United States

1. Introduction

The history of LSB or ROL, as it is more widely called in the nuclear industry, is one which can trace its roots to prototypical testing performed at INEL in the 1980s. Principal Investigators discovered a phenomena of rising-stem MOVs in that the stem factor of the valve would significantly change when the valve was stroked with flow moving through the valve (i.e., dynamic flow conditions) as compared to when the valve was stroked with no flow through the valve (i.e., static flow conditions). This variation in stem factor caused significant distress in the nuclear industry, as MOVs, many of which are in nuclear safety-related applications, were setup under static flow conditions, but were called upon to perform their safety-related functions under dynamic flow conditions. This led to many torque-seated MOVs being set regrettably low; unable to fully perform their safety-related functions and the eventual creation of U.S. NRC Generic Letters (GLs) 89-10 and 96-05.

Through the years, the nuclear industry has develop several standards and methods to ensure that safety-related rising-stem MOVs are set appropriately to account for ROL effects. One such standard, ASME QME-1-2007, “Qualification of Active Mechanical Equipment Used in Nuclear Power Plants,” goes so far as to require that the valve vendor “verify [the] applicability of the stem-to-stem-nut coefficient of friction and the load sensitive behavior of [each] production valve assembly to the qualified valve assembly through the use of specific test data or a test based qualification methodology.” Simply put, valve vendors either needed to perform a combination of dynamic and static testing to identify actual LSB on each production valve or the valve vendor needs to execute the EPRI PPM for the valve[2] to be in conformance with QME-1.

Parallel requirements for establishing stem-to-stem-nut coefficient of friction (COF) and LSB exist in the ASME *Operation and Maintenance of Nuclear Power Plants*, Division 1, OM Code: Section IST (OM Code), Mandatory Appendix III; specifically, under the requirements for design-basis verification tests. As presented in many public meetings, the U.S. NRC will accept four methods to satisfy the design-basis verification test requirement:

- Perform dynamic and static flow tests to identify the change in stem-to-stem-nut COF and LSB of the valve
- Execute the EPRI PPM to establish a reasonable MRT and apply conservative LSB assumptions
- Extend test data from similar valves under similar conditions at the site
- Extend test data from similar valves under similar conditions from other sites (i.e., JOG)

With the third and fourth methods being unavailable to new plant construction, and to satisfy the requirements of QME-1, Westinghouse Electric Company has executed the EPRI PPM for the active MOVs with a rising stem as part of the construction of the domestic *AP1000*® plants.

This paper will provide a background of the active safety-related MOVs at this nuclear plant, summarize the methodology used by the valve vendor to ascertain the MRT, summarize the methods used to establish the MRT using the EPRI PPM, as well as compare of the MRT established by the valve vendor to the MRT established using EPRI PPM.

2. Materials and Methods

2.1 Background of the Active Safety-Related Valves in the *AP1000* Plant

The *AP1000* plant was the first Generation III+ plant to be available for commercial nuclear power production. Generation III+ plants utilize passive safety system to cool the reactor core in the event of a design-basis accident. As such, traditional safety systems (e.g., RHR, CVCS, SI, ECCS, CSS), when present, are non-safety, control grade systems, affording the utility the benefit of a reduced population of safety-related MOVs while still being able to perform typical plant operations in familiar manner. Figure 1 shows a comparison of the number of active safety-related MOVs at the *AP1000* plant to a typical domestic commercial operating plant.

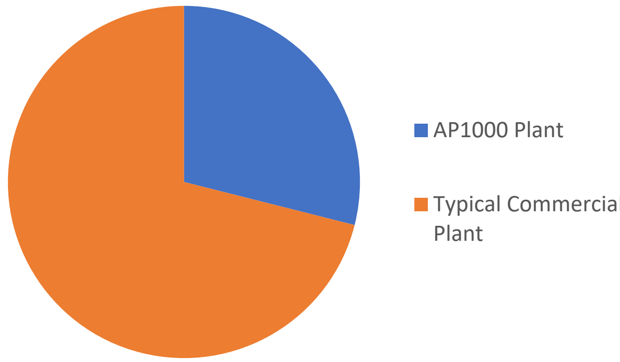

Figure 1: Number of Active Safety Related Motor Operated Valves Comparison

All safety-related MOVs with rising stems fall under the PV01 valve commodity and can be categorized by active vs non-active, valve type, and actuator control scheme with relative populations by valve datasheet, as depicted in Figure 2. Blue categories in Figure 2 indicate the valve has a safety-related function in either the opening or closing direction. Red categories indicate a passive safety function. The datasheets shown on the outermost ring of the sunburst chart shown in Figure 2 are sized by their relative populations of valves. As an example, there are four times as many valves built to datasheet 116 as datasheets 111, 119, or 120. Each successive ring, moving from the outermost to innermost, provides an additional descriptive category for the valves in that datasheet. Continuing with the example of datasheet 116, the sunburst chart indicates that valves built to datasheet 116 are motor-operated gate valves, which are torque seated, and have an active safety function in the closing direction. It is the gate and globe valves in this portion of the sunburst chart which are most at risk for failures to perform safety function due to LSB (i.e., torque-seated valves with active safety functions in the closing direction).

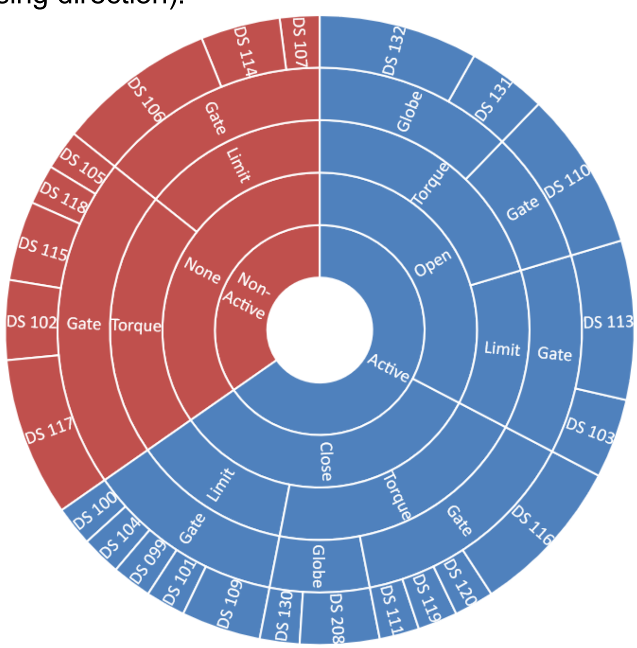

Figure 2: Rising Stem Motor Operated Valves in the AP1000 by Safety Related Status, Valve Type Actuator Control Scheme, and Relative Population

2.2 MRT by Vendor Sizing Methodology

A single valve vendor was chosen to supply the vast majority of the PV01 valve commodity. While the vendor's sizing calculation contains methodologies for sizing both gate valves and globe valves, gate valves outnumber globe valves in the PV01 commodity of the *AP1000* plant by a ratio slightly greater than 4:1. Additionally, all but three of the globe valves in the *AP1000* plant have opening safety-related functions. For these reasons, the discussion of the vendor's sizing methodology for valves in the *AP1000* plant in this paper will focus on gate valves with closing functions.

In the *AP1000* plant, the MRT of a PV01 commodity gate valve with a closing safety function, will be based on one of two methodologies, with the more conservative methodology for the valve being chosen. The first method calculates the MRT as a function of packing drag, stem ejection load, and a wedging force, where the wedging force is function of mean seat diameter, pressure required to seal the valve (based on the vendor's experience), and an unwedging constant (again, based on the vendor's experience). This methodology provides confidence that the valve will have enough closing thrust to maintain a good seal. The second method calculates the MRT as a function of packing drag, stem ejection load, and differential pressure load, where the differential pressure load is a function of maximum differential pressure, mean seat diameter, and valve factor. This methodology provides confidence that the valve will have sufficient thrust to overcome the drag forces of the disc riding across the seat.

In either method, the MRT is calculated, uncertainties are applied and then the minimum required torque is calculated, using the standard formula for ACME power screws, such that actuator overall gear ratios and motors can be selected. Imbedded in the use of this formula is the assumption that the stem COF equals 0.20. This is typically a conservative assumption as the stem COF for most valves varies between 0.7 and 0.15.

2.3 MRT using EPRI PPM

The EPRI PPM is a methodology for calculating MRT which has been endorsed by the U.S. NRC. This methodology is available to all domestic commercial power plants as members of EPRI's NMAC. As such, considerable time will not be spent discussing the methodology in this paper. Suffice it to say, the methodology is based on underlying assumption that the valve must overcome several loads to perform is function. In the closing direction, these loads include stem ejection force, packing drag, disc drag forces on guides and seats resulting from differential pressure and momentum effects of water in the upstream piping. The methodology even goes so far as to calculated line loads resulting from disc of gate valves tipping in the flow stream and causing near line contacts on valve guides and seats. As such, detailed design geometry of the valve's internals is used as input to this methodology. It is a complex and comprehensive methodology for establish the minimum required thrust to operate a valve.

The EPRI PPM does not, however, account for any ROL effects. These uncertainties must be applied outside of the PPM methodology.

2.4 Application of Uncertainties

The application of uncertainties in the vendor's sizing calculation was completed in one of two ways, depending on the actuator control scheme. For torque-seated valves, a 10% control switch repeatability, 26.4% random ROL uncertainty, and 10% test equipment accuracy were combined using SRSS method and then adding an additional 5.6% bias ROL uncertainty for a total uncertainty of 35.5%. For limit-seated valves, a 1% control switch repeatability and 10%

test equipment accuracy were combined using SRSS method for a total uncertainty of 10.1%, which were then rounded to 10.5% for conservatism. These uncertainties were then directly applied to the MRT discussed in Section 2.2, as applicable, to establish MRT with uncertainties.

Because the vendor's methodology includes application of uncertainties and the EPRI PPM does not, the two methodologies cannot be directly compared. Therefore, such that a comparison could be made regarding which methodology was more conservative, Westinghouse utilized the Teledyne Testing Service computer program MIDAS. MIDAS is a configuration control database with capabilities to calculate minimum required thrust and actuator capability. The program is capable of calculating minimum required thrust in a host of different ways, from calculations based upon packing drag, stem ejection load, and differential pressure similar to the second vendor's method for calculating MRT, to inclusion of results of EPRI PPM calculation of MRT. The program can then apply uncertainties such as control switch repeatability, spring pack degradation, stem lubricant degradation, and ROL to that MRT to establish the MRT with uncertainties. Additionally, the program can establish the minimum available actuator design capability, applying such degradation methods as reduced voltage, the BWROG's DC motor methodology for motor loading effects, and elevated ambient temperature effects. Comparison of the minimum available actuator design capability to the MRT with uncertainties gives the MOV program owner an estimation of the design margin of the valve.

3. Results and Discussion

Westinghouse Electric Company executed the PPM for each of the active rising-stem MOVs in the PV01 Commodity to establish the MRT for each of those valves. The results of those calculations were then input into MIDAS and compared to the MIDAS output from a previous effort which used the vendor's sizing methodology, modified to remove uncertainties, as input. A comparison was then made between the results of the vendor's sizing methodology, the MIDAS runs using the vendor's sizing as input, and the MIDAS runs using the EPRI PPM as input.

A similar comparison is made in Figures 3, 4, and 5. Figure 3 shows a comparison of the torque-seated valves with closing safety-related strokes. Figure 4 shows a comparison of limit-seated valves with closing safety-related strokes. Figure 5 shows a comparison of valves with opening safety-related strokes. In each of these figures are groups of columns. The first in each set, the light blue column, represents the vendor's MRT with uncertainty. The second in each set, the red column, represents the MRT with uncertainty from MIDAS using the vendor's sizing as input. And the third in each set, the green column, represents the MRT with uncertainty from MIDAS using EPRI PPM as input. Additionally, a dark blue column in included, serving as the backdrop to each of the previously mentioned colored columns. This backdrop column represents the maximum allowable thrust, which has been adjusted down based on expected test equipment accuracy. It should be noted that valve tags and axis labels have been intentionally obfuscated from these figures for proprietary concerns. Additionally, only one valve from a valve family (valves with similar results, such as valves from the same datasheet) have been shown.

As can be seen by a review of Figure 3, 4, and 5, in some cases (10 of 16), the vendor's original sizing methodology is the most conservative. In others (2 of 16), the MIDAS calculations using the vendor's sizing methodology as input is the most conservative. And in others still (3 of 16), the MIDAS calculations using the EPRI PPM as input is the most conservative. In one case, the vendor's original sizing methodology and the MIDAS calculations using the vendor's sizing methodology as input were approximately equally conservative, and both were more conservative than using EPRI PPM and applying uncertainties. It is also noted that in a few instances in Figures 4 and 5, the vendor's sizing methodology MRT (light blue column) exceeds the maximum allowable thrust (dark blue column). This is a result of applying the uncertainty of test equipment accuracy to both the MRT as well as the maximum allowable thrust. In practice, the test equipment accuracy need only be applied to the thrust reading in the field.

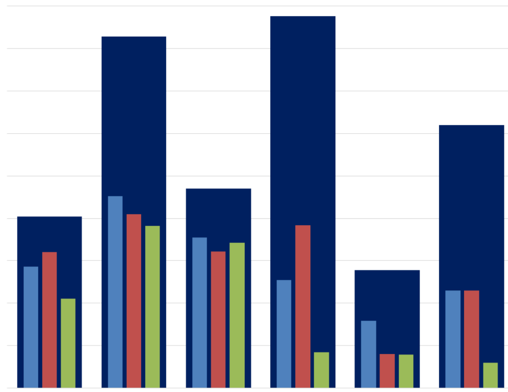

Figure 3: Comparison of MRT with Uncertainties for Torque Seated Valves with Closing Safety Functions

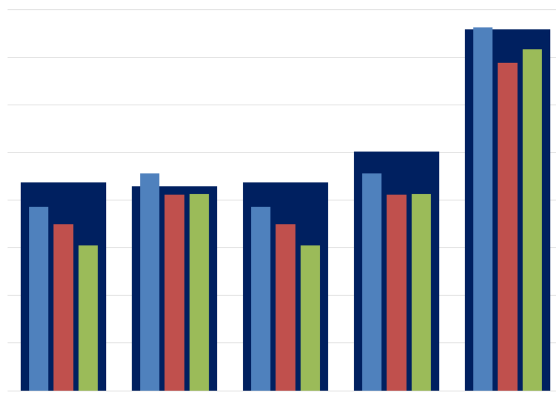

Figure 4: Comparison of MRT with Uncertainties for Limit Seated Valves with Closing Safety Functions

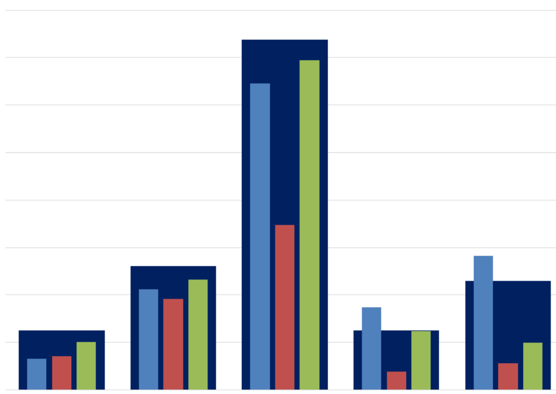

Figure 5: Comparison of MRT with Uncertainties for Valves with Opening Safety Functions

4. Conclusion

Three conclusions can be drawn from the information presented herein. Those conclusions are:

1. Some valves in the PV01 commodity require EPRI PPM to be basis of MRT for calculation of functional margin.
2. For the valves most susceptible to LSB (see Figure 3), EPRI PPM is not the most conservative method for establishing MRT.
3. Use of EPRI PPM for any valves which it is not the most conservative method for establishing MRT will result in margin recapture.

Acknowledgements

The authors are indebted to Ms. Silvia Ortega and Mr. Oriol Noguerea of Westinghouse Electric Company for their assistance in executing and documenting the EPRI PPM for the valves described herein.

The authors are also indebted to Mr. Tuan Quoc Huynh, Mr. Wendell Lynn, Mr. Mark McDaniel, and Mr. Dean Lurk of Southern Nuclear Company.

References

1. ASME Standard QME-1, “Qualification of Active Mechanical Equipment Used in Nuclear Power Plants,” 2012 Edition.

2. ASME Record 19-1033, “QME-1 – 2012 through 2017: QV-7463.3, Production Valve LSB,” July 16, 2019.

OMN-26 Optional Code Case for MOVs

Ted Neckowicz

Member MOV Subgroup

OMN-26 Optional Code Case for MOVs

Alternate Risk-Informed and Margin Based Rules for Inservice Testing of Motor Operated Valves

Ted Neckowicz, Member MOV Subgroup

What is OMN-26

- Currently under Appendix III, the maximum MOV Inservice Test Interval allowed is 10 years regardless of Risk Significance or Margin.
- OM Code Case OMN-26 via an Inquiry provides alternative requirements to several paragraphs of Appendix III which support Risk-Margin Informed Maximum Inservice Testing Intervals.
- For High Margin MOVs, this Code Case supports maximum Inservice Test Intervals of up to 9 years for HSSC MOVs and 12 years for LSSC MOVs.
- Conversely, the Code Case mandates more restrictive maximum intervals for lower margin MOVs which have little tolerance for in-service degradation.

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ASME
SETTING THE STANDARD

Case OMN-26

Approved Dec 2019

Case OMN-26
Alternate Risk-Informed and Margin Based Rules for Inservice Testing of Motor Operated Valves

Inquiry: What Risk-Informed alternatives to Appendix III Paras/Subparas: III-3310, III-3700, III-3721 and III-3722 may be used to extend the Maximum Inservice Test Interval beyond 10 years?

Reply: It is the opinion of the Committee that the following alternatives may be used:

Background: Maximum Inservice Test Intervals allowed under Code Case OMN-1 and Mandatory Appendix III are limited to 10 years regardless of the available MOV functional margin and/or MOV risk significance. This maximum 10-year test interval limit was established by NRC regulation under Generic Letter (GL) 96-05 directives and NRC approved US Nuclear Industry (i.e. Joint Owners Group (JOG)) documents outlining the requirements for a safety related MOV Periodic Verification Test (PVT) Program. In the 20 year period since the onset of NRC mandated GL96-05 MOV Programs, US Nuclear Licensee MOV Programs have demonstrated many margin stable and/or High Margin MOVs where margin degradation is of minimal concern. Years of actual MOV performance test data for many such MOVs can readily justify the extension of their inservice test intervals from their current JOG Risk-Based MOV PVT Program maximum test intervals of 6 years (for High Risk) and 10 years (for Low Risk) to longer test intervals more aligned with MOV Division Outage scheduling considerations for both PWR and BWR US Nuclear Licensees.

Applicability: See Applicability Index

1. Inservice Test Intervals

In lieu of Subparagraph III-3310(c), the following applies: The maximum inservice test interval shall not exceed 10 years unless Risk Informed Testing under the alternative requirements from Paragraph 2 below apply. MOV inservice tests conducted per para. III-3400 may be used to satisfy this requirement.

2. Risk Informed MOV Inservice Testing

In lieu of Paragraph III-3700, the following applies: Risk-informed MOV inservice testing that incorporate risk insights in conjunction with MOV Functional Margin to establish MOV grouping, acceptance criteria, exercising requirements and test interval may be implemented.

3. HSSC MOVs

In lieu of Subparagraph III-3721, the following applies: HSSC MOVs shall be tested in accordance with para. III-3300 and exercised in accordance with para. III-3600 while applying the following HSSC MOV Risk insights and limitations:

(a) HSSC MOVs that can be operated during plant operation shall be exercised quarterly, unless the potential increase in core damage frequency (CDF) and large early release (LER) associated with a longer exercise interval is small.
(b) For HSSC MOVs, the maximum inservice test interval shall be established in accordance with Table 1 of this Code Case.

4. LSSC MOVs

In lieu of Subparagraph III-3722(d), the following applies: For LSSC MOVs, the maximum inservice test interval shall be established in accordance with Table 2 of this Code Case.

Background

- Maximum Inservice Test Intervals allowed under OM Code Case OMN-1 and Mandatory Appendix III are limited to 10 years regardless of the available MOV Functional margin and/or MOV Risk Significance.
- This maximum 10 -year test interval limit was established by NRC regulation under Generic Letter (GL) 96 -05 directives and NRC approved US Nuclear Industry (i.e., Joint Owners Group (JOG)) documents outlining the requirements for a safety related MOV Periodic Verification Test (PVT) Program.

Basis for Change

- In the 25+ years since the onset of NRC mandated GL96 -05 MOV Programs, US Nuclear Licensee MOV Programs have demonstrated many margin stable and/or High Margin MOVs where thrust and/or torque margin degradation is of minimal concern.
- Years of actual MOV Performance Test Data for many such MOVs can readily justify the extension of their Inservice Test Intervals from their current JOG Risk-Based MOV PV Program maximum test intervals of 6 years (for High Risk) and 10 years (for Low Risk) to longer test intervals (i.e., 9 or 12 years) more aligned with MOV Division Outage scheduling considerations for both PWR and BWR US Nuclear Licensees.

Limitations

- Code Case OMN-26 provides alternative requirements to several paragraphs of OM Code Appendix III which support Risk-Margin Informed Maximum Inservice Testing Intervals.
- The Mandatory Appendix III paragraphs impacted by the proposed Code Case include: III-3310, III-3700, III-3721 and III-3722.
- Only those plants, implementing Appendix III may implement OMN-26 via an IST Program Relief Request.

Considerations

- OMN-26 changes are in line with current Risk-Informed philosophy
- OMN-26 changes are small and can be readily adopted with negligible loss of MOV performance and/or safety system reliability
- OMN-26 High Margin interval changes align with the desire of many licensees to adopt an outage division MOV testing strategy. The current 6 and 10 -year JOG Program based High-Margin Maximum Intervals do not support this strategy. This will encourage licensees to adopt Appendix III as soon as practical rather than wait for their next 10-year Inservice Test Program update.
- OMN-26 reduces the maximum test interval for HSSC MOVs allowed by Appendix III from 10 years to 9 years commensurate with Risk Informed Methodology.

Special Treatment for Very High Margin MOVs Subject to Periodic DP Testing

- Routine safety related system pump testing (typically performed quarterly) exercises some MOVs at or above design basis DP conditions (i.e., DBDPT) which are those DP conditions experienced during a design basis accident.
- While not at design basis voltage and temperature conditions, this testing provides periodic demonstration of MOV design basis DP capability.
- OMN-26 allows extending the Maximum Inservice Test Interval for applicable DBDPT MOVs with Very High Margin (>20%) to 12 Years for HSSC MOVs and 16 Years for LSSC MOVs respectively.

Benefits to Licensee

- OMN-26 maximum MOV Inservice Test Intervals are better aligned to Divisional Outage MOV Scheduling.
- Based on typical MOV Program populations, the Longer MOV Test Intervals allowed under OMN-26 should result in significant MOV Diagnostic Test reductions and implementation costs on an annual basis of up to 25% or more.
- Limerick Generating Station is expected to see a reduction in the average number of MOV Inservice Diagnostic Tests annually from 33 to 27 (18% reduction) by implementing OMN-26 without exercising credit for MOVs tested routinely at DP conditions. This is largely driven by the majority of MOVs being Low Risk.

OMN-26 Maximum Inservice Test Intervals > 10 Years

1. High Margin, LSSC MOVs. (12 Years)
2. Very High Margin, HSSC MOVs that are periodically tested at design basis DP conditions (DBDPT) (12 Years)
3. Medium Margin, LSSC MOVs that are periodically DBDPT (12 Years)
4. Very High Margin, LSSC MOVs that are periodically DBDPT (16 Years)

OMN-26 Maximum Inservice Test Intervals Optimized for Divisional Outages

Except for Low Margin HSSC MOVs, the Maximum MOV Inservice Test Intervals are optimized for Divisional Outage Scheduling (i.e., 4, 9, 12, 16 years).

- 9 years is optimal for PWRs restricted to 18 month refueling outages (Every 6-18m refuel outages, O6)
- 12 years is optimal for both PWRs and BWRs and supports both 18 month (O8) and 24 month (O6) refueling outages

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OMN-26 Focuses Inservice Testing on Low Margin MOVs

Code Case OMN-26 will focus more attention and Inservice Testing on the Low and Medium Margin MOVs. This is expected to drive licensees to improve MOV Margins in order to attain High Margin Status and enjoy the benefits of extended Inservice Test Intervals and Divisional Outage Optimization.

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Comparison of JOG MOV Periodic Verification and OMN-26 Risk-Margin Informed Code Case (RMI CC) Based Maximum MOV Inservice Test Intervals

	Maximum Inservice Test Intervals (Years)							
	HSSC MOVs				LSSC MOVs			
MOV Margin	JOG MOV PV Program	Appendix III	OMN-26	OMN-26 w/DBDPT	JOG MOV PV Program	Appendix III	OMN-26	OMN-26 w/DBDPT
Low (<5%)	2	10	2	4	6	10	4	9
Medium (≥5% and <10%)	4	10	4	9	10	10	9	12
High (≥10% and <20%)	6	10	9	9	10	10	12	12
Very High (≥ 20%)	N/A	10	9	12	N/A	10	12	16
Description ->	Existing Standard	Existing Code	New RMI CC	New RMI CC	Existing Standard	Existing Code	New RMI CC	New RMI CC

OMN-26 Implementation

Exelon has submitted a relief request and is planning on implementing OMN-26 for all sites implementing Mandatory Appendix III. These include the following Nuclear Sites:

Fully Implemented – Limerick – All MOVs have been fully evaluated and test intervals adjusted for OMN-26.

Partially Implemented – Peach Bottom, Calvert Cliffs, Ginna, Nine Mile Point, Braidwood, Clinton – MOVs are evaluated as planned MOV Testing approaches.

Note: Exelon conservatively treated Medium Risk MOVs as HSSC MOVs with respect to OMN-26 Implementation.

Thank You for your attention!

Questions or Comments?

Contact Info:

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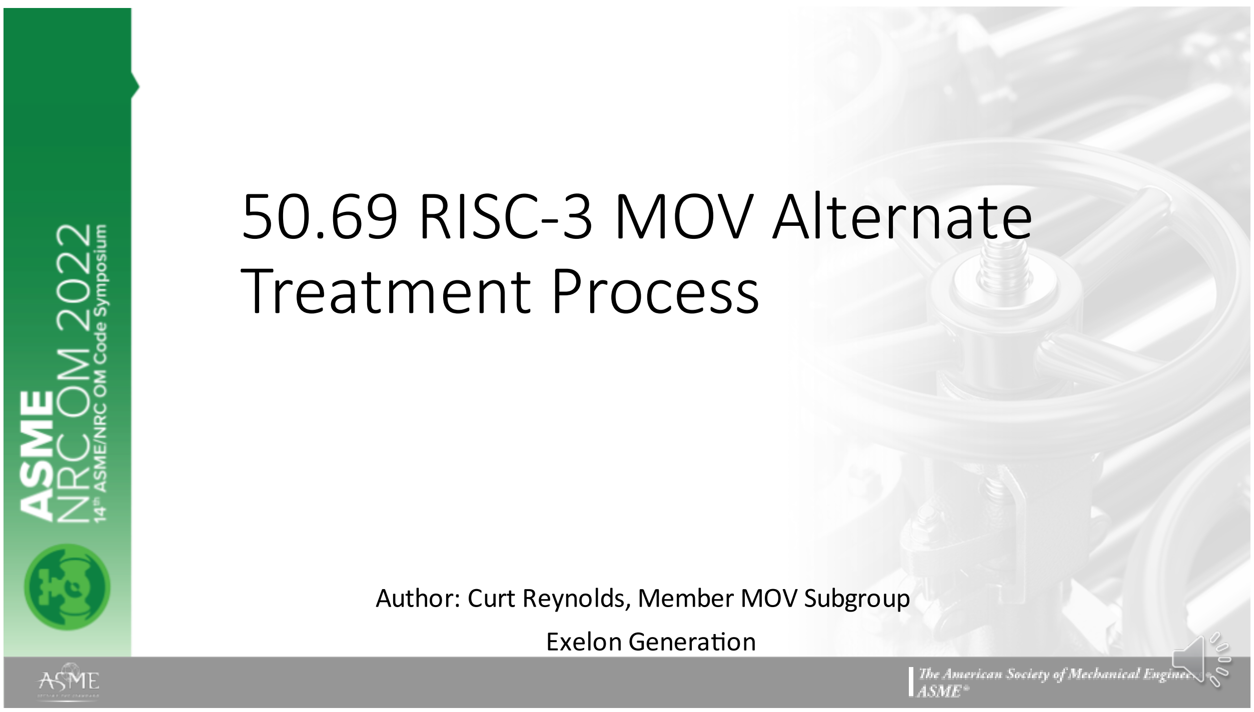
50.69 RISC-3 MOV Alternate Treatment Process

Curt Reynolds
Member MOV Subgroup
Exelon Generation



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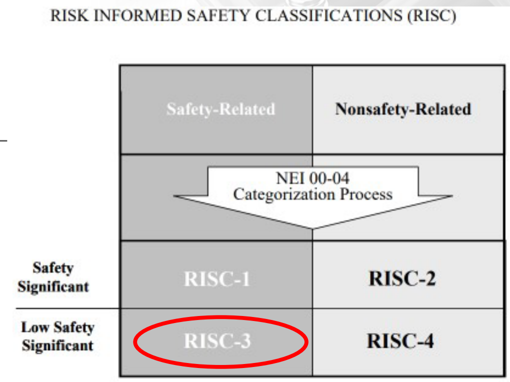
What is a 50.69 RISC-3 component?

10 **CFR** § **50.69** allows for Risk -informed categorization and treatment of structures, systems and components for nuclear power reactors.

NEI 00 -04 (Rev 0)
https://www.nrc.gov/docs/ML0529/ML052910035.pdf

"The 10 CFR 50.69 categorization process will identify some safety -related SSCs as being of low or no safety -significance (LSS) and these will be categorized as RISC -3 SSCs"



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RISC -3, MOV Alternate Treatment Plans (ATP): Why do we need them, and what are they?

WHY:
An alternate process for *Inspection, Testing and Corrective Action for* RISC-3 SSCs is <u>required</u>.

WHAT:
MOV ATPs provide "Reasonable Confidence" RISC -3 MOVs are, and will remain, fully capable of performing their design basis safety functions.

Alternate Treatment Requirements per 10 CFR 50.69(d)(2)

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Key Tasks

Key Tasks ensure continued MOV functionality and design basis capability.

- Conservative maximum allowable intervals are established for each *Key Task* based on site OE and general MOV Program valve performance history.

50.69 Savings?

Longer PM intervals, Grouping for testing.

Attributes

Attributes are key Indicators that an MOV is capable of performing its design basis function.

- Attribute selection is based on site OE and Program structure.
- Attributes should be affected (maintained or monitored) by the performance of Key Tasks.

Margins
COF values

Field Inspections
Ambient / service conditions
Operation frequency

Performance stability
Diagnostic anomalies

Adverse trends
Unresolved Part 21 actions

Attribute Thresholds

Thresholds are Attributes values that indicate the level of confidence in valve capability.

Example

Design COF Threshold Ranges	Stem Lubrication Interval
<0.15	Existing stem lube interval is maintained
Between 0.15 and 0.2	Stem lube interval may be extended to every 6 years
>0.2	Stem lube can be extended to the maximum Key Task interval

- Document Key Tasks, and Thresholds in procedural guidance to ensure intervals are consistently applied for each MOV.

Approach to ATP creation.

Identify maintenance activities (*Key Tasks*) necessary to maintain MOV performance.

Select *Attributes that are* critical MOV performance Indicators.

Establish Attribute Thresholds.

Perform review of each RISC-3 MOV's design and historical performance relative to Thresholds to determine the appropriate ATP.

Note: Conservative valve performance relative to Attribute thresholds support longer Key Task intervals.

Reasonable Confidence

ATPs are intended to provide Reasonable Confidence of a valve's continued capability.

To ensure Reasonable Confidence is demonstrated, testing is required.

- With the removal of RISC-3 components from the MOV Program, Grouping is appropriate.

Grouping – Finally a place where it pays Dividends!

RISC-3 MOVs can be organized into Groups comprised of MOVs with the same or "nearly the same" valve & actuator design attributes.

Within a Group, only <u>Representative Valves</u> require diagnostic testing.

- Each Group must contain at least one Representative Valve

- Generally, MOV(s) with the lowest margin should be selected as Representative Valves.
- If adverse trend(s) exist for a valve in the Group, it should be included in the Representative Valve population.

ATP – How do I do this?

Example - Hypothetical RISC-3 MOV Family:

- RISC-3 family contains 4 MOVs, each with the same valve, actuator and motor.
- MOVs are installed in Mild Ambient Conditions and Mild Service Applications.
- Grease condition for each valve in the family have historically been rated:
  - Stem Lube = 3
  - Actuator = 2

Valve	A	B	C	D
Functional Margin (%)	12	15	32	45
Design COF	0.12	0.18	0.2	0.2
Stem Nut Wear	N/A	N/A	Moderate	Moderate

ATP – How do I do this? – Initial Review

Hypothetical RISC 3 INPUTS:

- RISC-3 family contains 4 MOVs, each with the same valve, actuator and motor.
- Mild Ambient Conditions and Mild Service.
- Functional Margin for the Group: 12, 15, 32 and 45%.
- Design COF values: 0.12 for one MOV and the others range from 0.18 to 0.20.
- 2 of the 4 MOVs have stem nut wear evaluations classified as Moderate.
- Grease Ratings:
  - Stem Lube 3
  - Actuator 2

Minimum ATP – Initial Review:

Meets Minimum ATP Attribute Criteria (Supports Max. Key Task Intervals):

- Limitorque Elect/Mech PM: *Mild Ambient/Service, Grease Grade 2*
- Stem Lube: *Mild Ambient/Service*

Min-ATP does NOT apply due to the following issues:

- Valve ‘A’
  - Use of 0.12 Design COF is sufficiently low to warrant exclusion from the Group, reducing the size to 3. (Addressing the cause allows the valve to be added back into group.)
- Valves ‘B’, ‘C’ & ‘D’:
  - Does not meet margin threshold (15% too low), Stem lube Grease grade 3, adverse Stem Nut Wear Trends.

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ATP – How do I do this? – Detailed Review

Hypothetical RISC 3 INPUTS:

- RISC-3 family contains 4 MOVs, each with the same valve, actuator and motor.
- Mild Ambient Conditions and Mild Service.
- Functional Margin for the Group: 12, 15, 32 and 45%.
- Design COF values: 0.12 for one MOV and the others range from 0.18 to 0.20.
- 2 of the 4 MOVs have stem nut wear evaluations classified as Moderate.
- Grease Ratings:
  Stem Lube 3
  Actuator 2

ATP Determination – Detailed Review:

Valve Specific Attributes Affect Standard Key Task Intervals

- Limitorque Elect/Mech PM: **No Interval Change**
  - *Historical grease grade = 2, Mild Ambient/Service*
- Stem Lube: **Modestly Shorten Interval**
  - *Historical Grease Grade = 3*
- Diagnostic Test: **Modestly Shorten Interval**
  - *Lowest margin valve < 25%*
- Representative Valve Group Size:**Add 1 MOV to Testing Population**
  - *Moderate Stem Nut Wear to Group.*

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Questions?

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PSEG Salem and Hope Creek ASME OM Code Appendix III Implementation

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Abstract

PSEG Nuclear recently completed implementation of American Society of Mechanical Engineers (ASME) *Operation and Maintenance of Nuclear Power Plants*, Division 1, OM Code: Section IST (OM Code), 2012 Edition, Appendix III, "Preservice and Inservice Testing of Active Electric Motor-Operated Valve Assemblies in Light-Water Reactor Nuclear Power Plants," at both the Hope Creek and Salem nuclear power plants. This paper describes the changes required to the Motor-Operated Valve (MOV) and Inservice Testing (IST) Programs to implement the Appendix III requirements.

This paper describes the PSEG Motor-Operated Valve Program Changes, Implementation Challenges, and the status of the program since it was first implemented at Hope Creek Station in December of 2017. Topics include:

- Program scope Changes
- Changes to testing and analysis processes
- Software used to manage Appendix III program
- Documentation and reviews of testing and analysis
- Adjustments to PM frequencies and documentation of functional margin.
- The process for design basis verification testing, exercise testing, and inservice testing

1. Introduction

PSEG operates three nuclear plants at one site in southern New Jersey. Salem is a two-unit pressurized water reactor (PWR) and Hope Creek is a one-unit boiling water reactor (BWR) plant. Hope Creek was the 1st plant in the county to implement ASME OM Code, Appendix III, during our 10-year ASME OM Code update on December 21, 2017. Salem followed with Appendix III implementation on August 31, 2019.

The adoption of Mandatory Appendix III for MOVs required PSEG to combine the legacy Inservice Testing (IST) Program for MOVs governed by the ASME OM Code, Subsection ISTC, with the legacy MOV Program governed by NRC Generic Letters (GLs) 89-10 and 96-05.

The following sections of this paper summarize the actions taken to implement ASME OM Code, Appendix III, requirements at Salem and Hope Creek. This paper also summarizes the Software tools used at PSEG to assist the MOV engineers with the design, testing analysis, and documentation to ensure compliance with the Appendix III requirements.

2. Results and Discussion

Determination of MOV Program Scope

The first action taken to implement Appendix III is to look at the current MOV scope and the IST Program scope and combine the two program scopes. MOV Program scope for Appendix III was established based on the requirements per paragraphs ISTA-1100 of active safety-related MOVs and ISTC-1200, which provides exclusions.

HC Program scope - Technical Standard HC.ER-PS. ZZ-0513

Lists all MOVs in the program at Hope Creek and provides the basis for inclusion or exclusion from MOV Program. The Appendix III review resulted in the addition of three MOVs to the program. The three were all stop check valves (2 standby liquid control (SLC) valves and 1 reactor water cleanup (RWCU) valve). Hope Creek removed 5 valves from the program based on IST scope which previously identified the valves as having a passive safety function. The current scope of MOV program valves at Hope Creek is 204.

Salem Program scope - Technical Standard SC.ER-PS. ZZ-0002

Lists all MOVs at the Salem station and provides the basis for inclusion or exclusion from MOV Program. Salem did not add any MOVs to the program because of the Appendix III program review. Twelve MOVs were identified as passive in the IST Program and may be removed from the program in the future.

Current scope of program valves at Salem is 92 per unit for a 184 total.

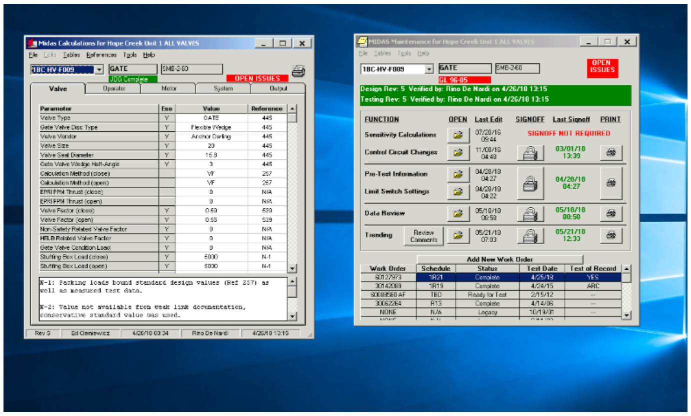
Establish the MOV Design Basis

Design Basis Verification Testing (DBVT) – Conducted to verify the capability of each MOV to meet its safety-related design-basis requirements. This may be a combination of testing and analysis to establish the initial design basis. This test is consistent with the initial GL 89-10 testing and may need to be repeated if the valve is replaced or modified.

PSEG used original DP testing for closure of GL 89-10 to establish the design basis. The valve factors we adjusted higher as required based on GL 96-05 (JOG) testing results. Salem performed DP Testing for our JOG Class D valves to establish the design-basis bearing COF for our Service Water Tricentric torque-seated butterfly valves. Some of the low margin JOG Class D valves will require periodic bearing replacements to maintain margin.

For new valves or modified valves, DP testing or EPRI PPM calculations are performed to establish the new MOV design basis. In addition, diagnostic testing frequency is reduced until trendable test data are available to extend the frequencies.

Design and testing documentation is maintained in our MIDAS Software program and records management. A screen shot of the software is provided below.



Perform preservice and inservice testing

PSEG has been using QSS strain gages during testing since 2005, and we had good trendable torque and thrust test data to establish a basis for IST frequency and margin. We continue to follow GL 96-05 to establish our test frequency based on MOV risk and margin. Additional diagnostic testing was not required prior to Appendix III implementation.

The last As-Left tests were designated as the Preservice test and the test frequency remained the same. Preservice testing and verification of test frequency is maintained by valve engineers and our SAP work management software. All Preservice testing and IST results are documented in MIDAS. We also track MOV testing in the IST software - EP-Plus IST.

Document MOV Risk

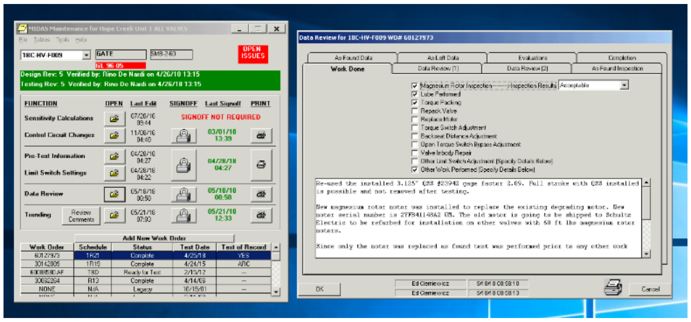
Appendix III, Section 3720, provides specific requirements for Low or High Safety significant components only. The existing MOV Program ranked MOVs as Low / Medium / High safety significance thru PRA analysis and expert panels.

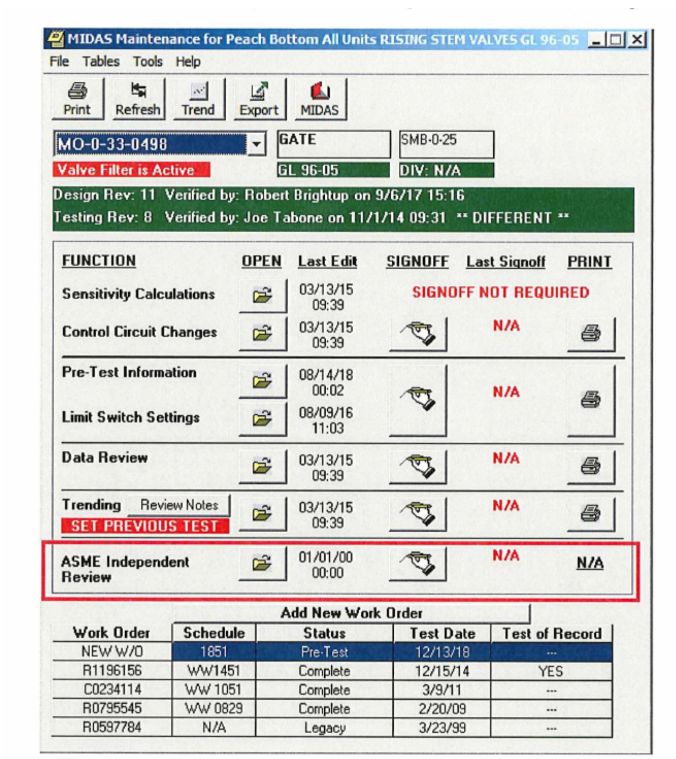
Hope Creek re-ranked all medium-risk valves thru expert panel to either High or Low risk establishing exercise testing frequency.

Salem chose to specify all medium-risk valves as high-risk valves to establish exercise-testing frequency.

Perform analysis and documentation of test data

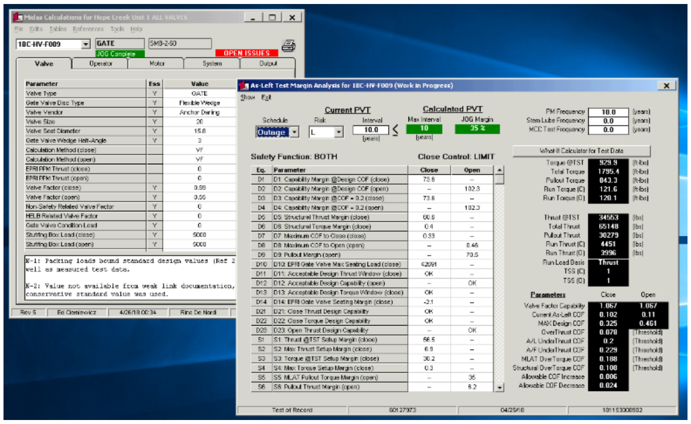
Appendix III, Sections 6200 thru 6300, provide requirements for analysis and evaluation of test data. The MIDAS software is used to provide test acceptance criteria to the technicians performing the test. Test data are captured in the MIDAS test and compared to acceptance criteria. As required under Appendix III, tabs are included in MIDAS to capture the valve engineer’s qualitative review to identify anomalous behavior in the test traces. Issues identified during testing are evaluated in our corrective action program (CAP). The engineering test review also performs a trending analysis of the MOV test data shall determine the amount of degradation in functional margin over time. A statement is made confirming that the current testing frequency is appropriate to ensure the MOV will not exceed margin limits over time. As required under Appendix III, an independent review of the test results is also performed and documented.





Calculation of MOV Functional Margin

ASME OM Code, Appendix III, section III-6400, provides requirements for design margin is calculated and maintained in MIDAS in the design module after test data is uploaded from the MIDAS test. Functional Margin in ASME was previously defined as PVT Margin. We did not make any changes to margin calculations in MIDAS. A trending module is contained in MIDAS test and performed after each inservice diagnostic test is performed. Functional margin is validated to be maintained on each program MOV until the next test interval.

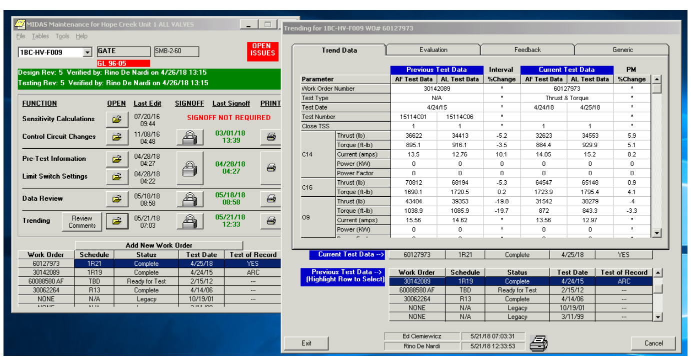


Establishing test Frequency

Appendix III, sections III-6200 to III-6300 provide requirements for analysis and evaluation of test data.

Compare test data to acceptance criteria. Data analysis shall include a qualitative review to identify anomalous behavior. Issues identified shall be evaluated in the CAP program.

Evaluation of MOV test data shall determine the amount of degradation in functional margin over time.



IST Software Tracking

“New” exam codes in IST Program Plan (ISTPP):

DIAG – This code applies to the periodic MOV diagnostic testing, previously performed for GL 96-05. The diagnostic test interval in the IST software will specify "App III", meaning that the interval is established per III-6440.

Expectation is that the plant will continue to perform DIAG at the intervals established for the GL 96-05 Program per the JOG Matrix, as a function of margin and Risk Rank.

FSX – This code applies to the new Full Stroke Exercise test as required by Appendix III. This code replaces the STO, STC, EO or EC codes in the ISTPP. There is no longer a safety direction emphasis – FSX is required for all active safety function MOVs. FSX interval will typically be as follows:

For High Safety Significance (JOG High and Medium) MOVs, exercise testing is performed every 92 days – unless an adequate Cold S/D or Refuel deferral is in place.

For Low Safety Significance (JOG Low) MOVs, exercise testing is performed every refuel cycle (18 months). Some LSSC MOVs may need to remain at quarterly intervals if the procedural valve stroking is inextricably linked to other valves, which must remain at the quarterly frequency.

STC– Based on the NRC Section 50.55a, "Codes and standards," in Title 10, "Energy," of the *Code of Federal Regulations* (10 CFR 50.55a) rulemaking from August 2017, some MOVs will still require stroke time testing. These are limited to MOVs with a valve-specific stroke-time criteria listed in Technical Specifications (and/or UFSAR/TRM). TrueNorth has identified the 31 MOVs which have specific Isolation Time criteria listed in TRM Table 3.6-1 or referenced specifically in the UFSAR. These 31 MOVs at Salem which still have the STC exam code in the ISTPP and the surveillance procedures will reflect closure time. The only criteria will be the TS / FSAR limit and not the previous IST trending limits.

Tracking Testing Requirements

EP-Plus IST software is used to track Exercise Testing and stroke testing (If required) and the supplemental verification is documented in the surveillance procedures, which are listed in the IST EP-Plus software for each valve.

The MOV MIDAS and MIDAS test software program is used to track DBVT, Preservice and Inservice Testing, Position Indication (PIT) Testing and Supplemental Verification of Stem-Disk integrity for Gate valves.

Position indication testing (PIT) requirements have been added to our MOV testing procedure MA-AA-723-300 which was a new requirement under Appendix III. PIT testing results are documented in the Diagnostic Testing PM orders in SAP, and are maintained in the records management program.

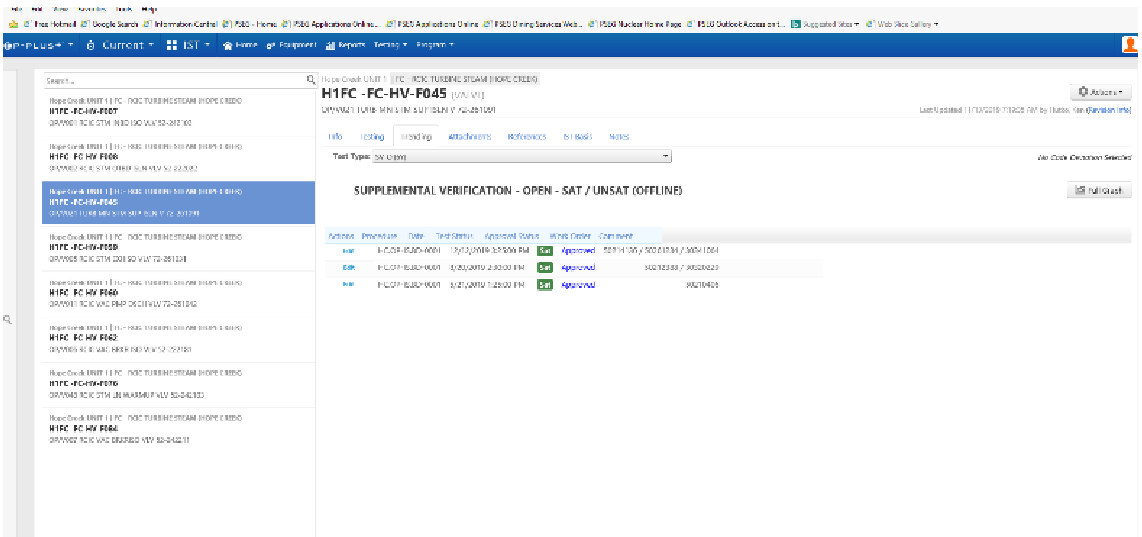
Testing and PM Work Order frequencies are controlled through our Work Management process and SAP Software

Supplemental verification

ASME OM Code, Subsection ISTC, paragraph ISTC-3700, refers to Appendix III for position verification testing of MOVs, which is performed per III-3300(e). MOV diagnostic test results are used to validate obturator movement if supplemental verification is not possible. Paragraph ISTC-3700 with the pointer to Appendix III for position verification testing which is performed per III-3300(e).

For other valves and MOVs that do not have a clear disk pullout identified during testing, including globe valves and some butterfly valves, other methods for obturator verification must be used. Credit may be by downstream flows, pressures or other pump surveillance parameters being met. Some valves require installation of temporary flow measurement / pressure gages.

For some MOVs, there is no easy method for supplemental verification, we are performing a local leak rate test to perform this task. We have also performed radiography on some emergency make-up valves, which only see flow during an accident.



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AP202, A Residual Heat Removal Pump In-Service Test **Rev: 52**

Attachment 2, Control Room Data Sheet (continued)

STEP	NOMENCLATURE	REQUIRED	ACTUAL	SAT/ UNSAT	PERF	
4.1.24.3	SUPPRESSION POOL SPRAY FLOW BC-HV-F027A, RHR LP A SUP POOL SPRY (SV-O) NOTE 7	≥ 540 NOTE 3	GPM			*
4.1.29	1-BC-V105, RHR PMP A OUTLET CHECK VALVE (EXERCISE CLOSE - EXC) NOTE 8	E11-N653A ≥ 70 psig	PSIG			*
		OHA A6-B1 NOT ALARMED	IN / OUT (Alarm Status)			
		Comp Pt D4373 NOT ALARMED	IN / OUT (Alarm Status)			
4.1.32	1-EG-V704, RHR PMP CLR AP202 LP A RTN CHK. (OPEN FUNCTIONAL - SKID) EG-HV-2520A, RHR PMP CLR SUP ISLN V (SV)	CPU PT D4755 **OR** D4757 ALARM CLEARED WHILE PUMP RUNNING NOTE 10				*

* In order to satisfy the requirements of the acceptance criteria, the SAT/UNSAT block must be marked SAT.

3. Summary

PSEG has fully implemented ASME OM Code, Appendix III, for the Salem and Hope Creek Stations. Engineers have been trained on the new Appendix III requirements and we use the MIDAS, MIDAS test and EP-Plus IST to document compliance with the requirements. Our SAP work management software and records management are also used to document testing, preventative maintenance and corrective actions required to comply with the ASME OM Code, Appendix III.

References

1. ASME *Operation and Maintenance of Nuclear Power Plants*, OM Code-2012.
2. *Code of Federal Regulations*, Title 10, Part 50.55a, Codes and Standards.
3. MPR 2524A, Rev. 1, Joint Owners' Group (JOG) Motor Operated Valve Periodic Verification Program Summary, September 2010.
4. NRC Regulatory Guide 1.192, Operation and Maintenance Code Case Acceptability, ASME OM Code, June 2003.
5. NRC IE Bulletin 85-03, Motor-Operated Valve Common Mode Failures during Plant Transients due to Improper Switch Settings, November 15, 1985.
6. NRC Generic Letter 89-10, Safety-Related Motor-Operated Valve Testing and Surveillance, June 28, 1989.

7. NRC Generic Letter 96-05, Periodic Verification of Design-Basis Capability of Safety-Related Motor-Operated Valves, September 18, 1996.

8. Generic Letter 89-04, Guidance on Developing Acceptable Inservice Testing Programs, April 3, 1989.

9. BWROG-TP-15-010, ASME Operation and Maintenance Code, Mandatory Appendix III Implementation Guide (Kalsi Engineering KEI 3441)

10. NUREG-1482, Revision 1, Guidelines for Inservice Testing at Nuclear Power Plants, January 2005.

Dynamic Restraints (Snubbers)

Track Chair: Glen Palmer, Palmer Group International, LLC, ASME Fellow

Obsolescence Management of Snubber Parts

Matt Palmer, PE, P.Eng.

Anvil Services, ASC-Engineered Solutions

Nuclear power is an essential infrastructure service provider that is facing many challenges. Shifting geopolitical climates, aging human and physical capital, and competition from other carbon-neutral energy sources create challenges to profitability. To maintain financial viability in this environment, individual facilities must navigate the operational challenges of maintaining aging equipment while running a safe and efficient plant.

Plant operators must balance sales and revenue generation against maintenance expenditures in terms of dollars and downtime. This is straightforward at the component level for a single valve or pump, but the degree of difficulty increases exponentially for the complex system that is a nuclear power plant. Compounding these challenges is the inescapable factor of age, which for domestic nuclear facilities is 39 years old (https://www.eia.gov/energyexplained/nuclear/us-nuclear-industry.php). For equipment requiring repair and replacement activities, the original equipment manufacturer (OEM) may no longer be in business, or they no longer hold an ASME certificate and maintain a 10 CFR Part 50, Appendix B, quality assurance (QA) program.

Preventative maintenance on facility components includes periodic inspection, testing, and repair or replacement of worn or damaged parts. There are also unplanned repair and replacement activities that can occur due to sudden component failure. When replacing or repairing worn, damaged or failed parts, the plant manager is confronted with 3 choices:

1) Contact the OEM to repair or replace the part
2) Replace the parent component of the damaged or failed part
3) Utilize reverse engineering techniques to perform an aftermarket repair or procure an aftermarket part

A detailed cost/benefit analysis of these paths forward is beyond the scope of this paper and is dependent on the particular scenario at hand, with no “one-size-fits-all” approach. However, in many cases, reverse engineering is a cost-effective option for procurement of long-lead, expensive, or obsolete parts.

What is Reverse Engineering?

Reverse Engineering (RE) is defined as “The process of developing technical information sufficient to obtain a replacement for an item by physically examining, measuring, testing existing items, reviewing technical data, or performing engineering analysis.”(3) This technique has been used throughout history to examine, reproduce, and improve on existing technologies. A famous example is the reverse engineering of ENIGMA code machines in World War II (WWII).

Today, methods vary from ad-hoc testing and examination to a rigorous formal treatment. Methods differ by organization and are documented in standards such as MIL-HDBK-115 available from the Army Corps of Engineers or in various technical publications from the Institute of Electrical and Electronics Engineers (IEEE) for software. In the Nuclear Power industry, precise guidance for RE of parts and components is given in Electric Power Research Institute (EPRI) Technical Report 107372, Rev. 1.

The EPRI approach was developed for use in nuclear safety-related power plant applications. This "best practices" guidance holds true for fossil fuel power and oil and gas facilities as well, and has become the basis for reverse engineering procedures adopted by Anvil Services, the engineering arm of ASC-Engineered Solutions (formerly Anvil Smith-Cooper International). To properly reverse engineer a part, the following steps must be performed:

1. Identify the application and function of the parent component or system and the objective of the reverse engineering activity.
2. Identify the design characteristics of the original item for reverse engineering.
3. Recover known and unknown item characteristics through physical testing, document reviews, and technical evaluation.
4. Establish a design for the replacement component
5. Review the replacement item design against the known, recovered, and inferred characteristics of the original component, including consideration for in-service and environmental conditions.
6. Determine if there are any disposition discrepancies between the replacement and original designs via a technical evaluation to document the replacement item's fitness for service.
7. Provide for stakeholder review and approval prior to fabrication of the replacement part.

It is worth noting that the forthcoming discussion of these steps and this method is through the lens of a manufacturer and designer of ferrous and non-ferrous metal components.*

> ***For a full treatment of the reverse engineering process for complex systems such as software, circuit boards, et. al., it is suggested the reader review applicable EPRI, IEEE or other industry guidance.**

ASME Code Basis for RE Activities

Repair and replacement of non-conforming components in a nuclear facility is essential for safe operation. Both the American Society of Mechanical Engineers (ASME) *Operation and Maintenance of Nuclear Power Plants*, Division 1, OM Code: Section IST (OM Code) and ASME *Boiler and Pressure Vessel Code* (BPV Code), Section XI, give rules for inspection and testing of these components to determine their suitability for initial or continued service. The ASME OM Code addresses performance testing of pumps, valves, and snubbers, and ASME BPV Code, Section XI, governs testing and verification of the reactor pressure boundary. As an example of these jurisdictional boundaries, the ability of a valve to close is verified through testing prescribed in the ASME OM Code, Subsection ISTC, and its ability to retain pressure through the body is governed through ASME BPV Code, Section XI, inspection.

Both the ASME OM Code and ASME BPV Code, Section XI, allow for repair and replacement activities. The OM Code delegates this responsibility to Section XI in ISTA-3300 (5). Section XI IWA-4000 addresses repair and replacement activities, and includes "welding, brazing, defect removal, metal removal by thermal means, rerating, removing, adding, or physically modifying pressure retaining items or supports, or adding systems." IWA-4140 allows for a 3rd party organization to perform repair or replacement activities regardless of the original item's construction code, so long as the 3rd party has a 10 CFR Part 50, Appendix B, program, and has demonstrated to the Owner's satisfaction their ability to carry out the required repair and replacement activities. The repair and replacement organization must still comply with all construction code requirements for any repair or replacement item, and a repair plan must be documented for approval by the Owner.

By omitting the requirement for an ASME audited QA program and application of Code stamp to the repair, ASME has recognized the need for 3rd party organizations to provide repair and replacement services. Reverse engineering is not mentioned in Section XI but is a vital component of the repair / replacement plan required by IWA-4150. Without recovery of the original design condition or intent, acceptance criteria for component repair or an equivalency evaluation of a replacement component cannot be defined. A 3rd party repair / replacement organization can utilize industry best practices by applying the guidance of EPRI TR-107372, Rev. 1, to the design component of their 10 CFR Part 50, Appendix B, program.

What are the benefits and risks of Reverse Engineering?

Whether or not to employ RE as a way of producing obsolete parts is a question of whether to use a proven and costly OEM part against an unknown and less expensive aftermarket part. An analogy to auto parts applies here – You can take your car to the dealership for OEM parts and service, but at a premium in dollars and time. You can also take it to your neighborhood garage where the aftermarket brake pads will work just as well for a fraction of the price. Even within brake pads, you can buy the "economy, daily driver, or premium" level of quality where the premium part may last longer than a base model OEM part.

The most typical benefits of RE are reductions in lead time and cost. As an example, a threaded rod ordered to an obsolete material specification would require a steel mill to produce a minimum lot size of 40,000 pounds mass (lbm) for a part that might use 40 lbm of material. Another example would be the use of castings in valve trim. If one was to order a casting to the original print, it is possible that the casting pattern or vendor no longer exists. In this scenario, the casting vendor would have to create a new mold and pour a batch of material that they may not typically work with.

In these instances, the OEM would quote a very high unit cost and long lead time to account for these challenges in working with an obsolete material. This is a common problem; the geometry and application of the part is not obsolete, but the material or manufacturing method used on the original item is. This can be overcome with sound engineering principles and by offering an available material. Therein also lies one of the risks of RE and, by definition, this would be a design change. If not properly evaluated with appropriate technical rigor, the replacement component performance may not be equivalent to the OEM.

Reverse Engineering "Like for Like" vs. Design Equivalency "Form, Fit, and Function"

By the textbook definition, for a component to be successfully reverse engineered, it must truly be "like for like" with no changes from the original part. For ferrous and non-ferrous metal parts, this includes all dimensional characteristics, and material properties such as chemical composition, mechanical strength, and others. All of this information can be known with enough time and samples for laboratory testing, but this is not always practical with compressed schedules and limited budgets.

For a part to be a true “like for like,” all design characteristics must be definitively known and recoverable by using the proper equipment. For example, the outer diameter of a valve plug is a critical dimension. Should the recovered dimension be too large, the plug will not fit the cage. Should the diameter be too small, the plug will not maintain alignment within the cage and a fluid leak will occur that will alter the valve’s flow characteristics.

In this application, typical clearances between the cage / plug interface are 0.002” to 0.003”, which would then require the re-manufactured plug to have an outer diameter (OD) of ± 0.001” from the recovered dimension. If the plug OD was recovered with a tape measure with a tolerance of ± 1/32”, this would be an unknown characteristic given the manufacturing tolerances required and the poor accuracy of the measurement. However, when measured with laser scanning equipment with tolerances of ± 0.0005” this dimension can be definitively known when taking into account the required manufacturing tolerance of ± 0.001” on the outer diameter.

It is sometimes argued that dimensional characteristics cannot truly be known unless the OEM tolerances are known. This statement is inaccurate in that it dismisses the maturity and standardization of sound machining practices. For example, the “bible” for CNC machining, Machineries Handbook (4), has been in print for over 100 years and has defined tight tolerances, interference fits, and assembly clearances for generations of engineers. It is likely that the same tolerances specified by the OEM are the exact tolerances that Anvil Services manufactures to. In addition, there have been vast improvements in CNC machining over the years, and the tolerances that were intended for manual machining 30 years ago can be reliably attained with much less variation on a modern CNC.

In some cases, characteristics cannot be recovered by measurement but must be inferred using what data is available and sound engineering principles. For example, material data is typically ascertained by using X-ray fluorescence PMI technology to recover chemical composition, and non-destructive hardness testing for material tensile strength. PMI technology can recover the UNS chemical composition for the alloy and stainless steels typically used in valve trim, but it cannot recover the material specification (ASTM, DIN, AMS, SAE) that it was manufactured to. Sometimes this can be recovered from a packing list or other documentation, but is usually not available. A practical example of this would be determining whether or not a cast or forged material was used in the manufacture of a valve cage.

Cast or Forged?

UNS J91540 is a commonly used martensitic stainless steel casting material covered by 4 ASTM specifications and is referred to as CA6NM. It is nearly identical in chemical composition to the forging UNS 41500 covered by an additional 10 ASTM specifications. The differences in chemistry are minor and are due to the differences between manufacturing a cast vs. forged material. There are also ASTM documents that explicitly state that the materials are equivalent. Both casting and forging are supplied equivalent tensile strengths depending on the final heat treatment, and the required tensile strength can be recovered from a hardness test.

A visual exam for cast markings can sometimes yield whether a material is cast or forged, but in many cases they have worn or been machined off. Ultimately, whether or not the original material of manufacture is a casting or forged, it may not be able to be recovered. Therefore, if the original material specification cannot be ascertained, a true “like for like” part cannot be supplied. However, if UNS J91540 and UNS 41500 can be considered equivalent materials, the “form, fit, and function” of the replacement part will be identical to the original.

Steam Generator Snubber Valve Replacement with Commonly Available Material

Steam generator snubbers are typically a Class 1 component support designed to ASME BPV Code, Section III, Subsection NF, that are designed to protect the steam generator during a seismic event. Depending on the design of the steam generator, many smaller units with a load rating on the order of magnitude of 100 kips [1 kip equals 1000 pounds force] can be used, or a few larger units with load ratings of 2000 kips or more. These very large units can weigh up to 5000 lbm and are very difficult to remove from containment for maintenance and testing. As a result, these units are either tested in situ, or the small externally mounted control valve can be removed for testing and replacement.

In this instance, ASC was asked to supply a replacement snubber control valve to swap in for a valve that needed testing. The OEM no longer manufactures these snubbers, and all dimensional drawings were available. What was not available was the specified material, SA-540, any grade, Class 4. SA-540 is a high-strength bolting and forging material that is an active ASME specification, but the very small amount (20 lbm) needed for manufacture of the valve made it cost prohibitive. Readily available stainless steels SA-240 and SA-479 types 304/316 were used in the manufacture of the replacement item.

SA-540 Class 4 requires 135 KSI ultimate and 120 yield strength, and Type 304/316 stainless steels specify 75 KSI ultimate and 30 KSI yield. Therefore, the materials of construction cannot be considered equivalent. The chemistry of the materials is also different, with SA-540 being a low chrome alloy steel vs. stainless steel. In order to satisfy the requirements of IWA-4000, a design report was done to ensure the replacement material satisfied the requirements of ASME BPV Code, Section III, Subsection NF. For this application, the weaker material was acceptable because the owner had de-rated the seismic load on the original equipment by approx. 60%.

Using Original Test Specification in the Qualification of Elastomers

ASC has been providing hydraulic snubbers since the 1960s. As such, there have been many changes to the supply chain since the initial scope of supply. An illustration of this is the #10 thread seal used on the 1974 vintage snubber and later. This seal is used in the snubber control valve and prevents leakage from the needle valve adjustment screw that controls the bleed rate.

This seal was discontinued by the OEM in 2017. The control valve design that uses this seal is obsolete, and ASC has an alternate that will deliver a longer life and higher operating temperatures. However, given the large installed base of the 1974 vintage, including existing programs for inspection, testing, and refurbishment, the cost to the fleet of obsolescence would be very high.

The challenge in developing a replacement seal is in the compounds used and the design of the metal washer that secures the elastomer in place. Through the design, qualification, and manufacture of hydraulic snubbers, ASC has abundant experience qualifying new seals and new compounds for use, but no experience in the design of seals themselves. Qualification of a new ASC designed seal must then be accomplished through testing and not design. As the

OEM, ASC has tested dozens of compounds from the 1970s to today, and has access to all the owner testing specifications from that time until now. This testing included radiation, thermal aging, and boric acid and steam exposure to name a few. Using this knowledge, ASC was able to recreate the testing performed on the original snubber qualifications. It also validated the dimensions of the steel washer that were reverse engineered from parts in existing stock.

Conclusion

In conclusion, maintenance cost pressures, long lead times, and part obsolescence are not going away. With advances in metrology, manufacturing and methods, reverse engineering is a reliable and cost- effective way of dealing with these challenges. A reputable vendor will differentiate themselves from the "parts pirates" by applying state of the art metrology with rigorous engineering analysis of all recovered design characteristics and a sound technical basis for any inferences made. In this way, true "like for like" or equivalent "form, fit, and function" parts can be supplied that will satisfy existing and technical performance requirements.

References:

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2. "When Was the Last Refinery Built in the United States?", last updated June 23, 2020, https://www.eia.gov/tools/faqs/faq.php?id=29&t=6

3. Guidance for the Use of Reverse-Engineering Techniques: Revision 1 to EPRI TR-107372. EPRI, Palo Alto, CA: 2018.3002011678

4. Oberg, Erik, 2020, Machineries Handbook, Industrial Press Inc.

5. 2020 Edition of the ASME OM Code.

Results of Mechanical Snubber Condition Monitoring on Degradation Rate Over Time

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Abstract

This paper summarizes the current results of Mechanical Snubber Condition Monitoring Programs implemented at certain operating U.S. nuclear power plants. The condition monitoring is utilized to validate reliability and extend service life. Service Life Monitoring is a requirement of the American Society of Mechanical Engineers (ASME) *Operation and Maintenance of Nuclear Power Plants* (OM Code). Subject operating units with large mechanical snubber populations instituted programmatic condition monitoring as early as 2005 and 2006. Degradation rates compared over time indicate that the programs resulted in an improvement in the reliability of the mechanical snubber population.

1. Introduction

Several operating plants with large mechanical snubber populations instituted programmatic condition monitoring after operating for many cycles with no such programmatic actions. Prior to that point, the reliability of the snubber population was primarily based on the functional testing program in accordance with Technical Specifications or applicable ASME Code requirements.

The implementation of condition monitoring was in response to both industry and site Operating Experience indicating potential for worsening degradation and failure rates. The condition monitoring program primarily consists of manually exercising each installed mechanical snubber on a rotating periodic basis. In most cases, individual mechanical snubbers are unpinned at one end and then manually stroked in place by a trained technician. In some instances, a mechanical stroking tool is used to exercise larger models of snubber which require greater force. The desired result is to redistribute the lubricant inside the snubber and thus recoat the internal surfaces. Exercising the snubber helps to prevent the lubricant from hardening over time as well. In addition, a trained technician performing the stroking can often detect minor degradation in early stages and allow a suspect snubber to be replaced or repaired prior to any significant impact upon the snubber function.

The results of such programs at several operating plants are summarized in this paper and indicate that such practices can result in significant improvement in the reliability of a mechanical snubber population. A review of actual performance data over time consistently shows a downward trend of the degradation and failure rates since the implementation of these condition monitoring programs. The data show that the degradation rate of previously untouched snubbers drops significantly on the second time through the population, and less dramatic, but significant, decreases thereafter. Current data indicate that the degradation may level off over time, but at an acceptable rate. This indicates that such programs are an effective tool in extending service life and reliability of the mechanical snubber population.

2. Methods and Data

All plants considered for this review implemented a method of manually exercising (stroking) the mechanical snubbers through their range of motion on some periodic basis. The number of snubbers so stroked and the periodicity varies from plant to plant depending upon site-specific preferences and limitations.

In the most clearly documented case, the snubbers are divided into 3 groups that are stroked in a staggered time frame over a 3-cycle period, resulting in 100% inclusion over the 3-cycle period. However, different intervals and population groupings have been used at various plants due to specific population and resource requirements.

As a measure of effectiveness, a degradation rate is determined by comparing the number of degraded and failed snubbers to the total number of snubbers that had any type of "hands-on" work performed during the current cycle (testing, stroking, removal/restoration). Over time, this measure provides trendable data representing a "living" picture of the overall reliability of the subject population.

2.1 Plant "A"

2.1.1 Plant "A" Background

Plant A is a two-unit site, both units being four loop pressurized water reactor (PWR) designs. The units began commercial operation in the mid 1980s. Initially, both units had large snubber populations. Unit 1 began commercial operation with approximately 1900 snubbers and Unit 2 had approximately 1100. Both populations were originally 100% mechanical snubbers.

A snubber reduction effort was implemented between 1990 to 1995. This resulted in a significant decrease in the number of installed snubbers, with a final reduction of approximately 50% in one unit and 40% in the other unit. Over time, some of the original mechanical snubbers have been replaced with hydraulic snubbers, but the populations remain over 85% mechanical snubbers.

Following the snubber reduction effort, it was recognized that the elimination of so many snubbers also meant that much redundancy was eliminated and that remaining snubbers in general had reduced margin regarding adverse impact on supported systems or components. This resulted in an even greater emphasis on the reliability of the remaining snubbers.

In the late 1990s and early 2000s, both site specific and industry operating experience indicated significant concerns pertaining to the reliable performance of mechanical snubbers over time. The functional testing failure rate of mechanical snubbers indicated an adverse trend, especially among snubbers with little or no history of previous inservice maintenance or testing. Due to the statistical sampling methods utilized to satisfy the testing requirements, many if not most of the installed snubbers in large populations might be untested for many years – and possibly for the life of the plant. These "untouched" snubbers seemed to be especially vulnerable to performance degradation. The implications of this were an increasing number of test failures over time. This would not only result in significantly more outage testing, but also more challenges to the design basis of the supported components and systems. It was recognized that a more complete maintenance program was needed to address the total population.

At that point, the existing snubber maintenance and testing program for the site was re-examined. It was noted that per an original Technical Specification requirement the mechanical snubbers on certain systems were inspected each outage for evidence of transient damage. This inspection was performed by manually stroking all the snubbers on those designated systems. Review of historical data showed that among those snubbers that were stroked each outage the degradation rate was much lower than those in the population that were not stroked. In fact, the data that were retrievable indicated that those snubbers had a degradation rate of about 10% over the first two outages, but then the rate dropped to be consistently between 2.5% to 3% over subsequent cycles.

However, that program only addressed about 35% of the total population. Over 65% of installed snubbers were not included. It was decided to expand the stroke program to include all snubbers, but to perform them on a periodic basis. The population was divided into 3 groupings, each representative of the overall population regarding size, system, and location. Each group was to be stroked every third cycle on a rotating basis. In this way, every snubber was to be stroked at least once every 3 cycles. Representative snubbers of those systems addressed in the Technical Specification transient inspection requirement were included each cycle to satisfy that requirement.

By utilizing a three-cycle period and utilizing a rotating schedule, it was possible to stroke 100% of the snubbers over that period without increasing the scope of individual outages. In fact, the number of strokes per outage was slightly reduced under the new program. It was also discovered that 20% to 30% of the strokes could be performed online utilizing system and train windows, or the snubber Technical Specification Limiting Condition for Operation (LCO) 3.0.8 to allow maintenance. In this way, outage scope was not increased.

The new stroke program was implemented in 2005 and 2006 for Unit 1 and Unit 2, respectively. At the time of this publication, each grouping of snubbers has undergone 3 to 4 cycles of stroking. The following data from those cycles indicate that the program has been highly successful in reducing the degradation rate and increasing reliability of the mechanical snubber population.

2.1.2 Plant "A" Performance Metric

The reliability metric used for Plant A is the "Total Degradation Rate." In laymen's terms, this is simply "Problems Found" versus "Snubbers Handled."

This metric is calculated for each cycle as the ratio of the total number of discrepancies to the total number of snubbers that are manipulated in any way during that cycle. For this metric, a discrepancy is any finding that requires further corrective action for a given snubber. Technicians are trained to conservatively identify anything that they deem unusual about a snubber's operation during stroking or testing. Such suspect snubbers are generally replaced as a preventive measure, even though they will often pass a subsequent operational readiness bench test. These snubbers are still considered as degraded due to the abnormal operation and counted in this metric. For the metric, any snubber that is replaced, scheduled to be replaced, or repaired due to a finding is counted as a discrepancy. Although the process is somewhat subjective, training enforces the objective of making conservative decisions regarding any questionable findings.

All mechanical snubbers that are manipulated or worked in any way are considered in the metric calculation. This includes those snubbers removed and tested in accordance with the sample plan requirements, service life monitoring testing, snubbers stroked during the cycle, snubbers removed and reinstalled as interference items, or any other activities that involve unpinning at least one end of a snubber assembly. By including all these activities in addition to the stroke program snubbers, the number of snubbers validated by “hands on” tasks generally far exceeds one-third of the total population each cycle.

2.1.3 Plant “A” Results

Data trending began with initial implementation of the expanded stroke program in 2005. The tables show the calculated Total Degradation Rate for each group overtime. The interval between data points for each group of snubbers is 3 cycles, approximately 4.5 years.

As an example of how the data are compiled consider the following inputs:

For the most recent Unit 1 Cycle for Group A (4^{th} Time for this group), a total of 39 mechanical snubbers were functionally tested and 269 other mechanical snubbers were stroked or otherwise manipulated during the cycle. This results in a total of 308 snubbers worked during the cycle. There were no sample test failures; however, two snubbers were replaced as preventive maintenance due to problems noted during stroking. Thus, the resultant rate is 2/308 or 0.65%. This calculation is performed each cycle.

As can be seen by the tabulated data, each group has shown a downward trend in the degradation rate over time. Conversely, this can be denoted as an increase in population reliability.

It is noted that the various groups do show some deviation in degradation rate relative to the other groups. This is attributed to the fact that although the groups are generally representative of the population at large, they are not identical to each other. In order to efficiently bundle outage work, some of the groups are more heavily weighted with snubbers in specific areas, which can result in more exposure to severe environments, which in turn contributes to varying discrepancy counts. For example, snubbers located in the pressurizer cavity are grouped to be worked together. Likewise, snubbers in steam doghouses are grouped together. This facilitates more efficient and safer work conditions for the respective cycles, but can result in some data differences due to some groupings having more snubbers in harsh environments than others.

At this time, the disparity between the groups is not considered to be of extreme significance, relative to the fact that all groups indicate a downward degradation rate. It is anticipated that the delta between the groups will narrow over time, as the degradation rates for all groups is expected to level off in the long term. However, further data trending is needed to confirm such assumptions.

Related to this data, a review of the degradation rates prior to the implementation of the 100% stroke program indicates that previous rates of 2.5% to 3% were largely due to degraded and failed functional tests of snubbers which were NOT included in the previous stroke scope. It can be surmised that had those snubbers been included in that scope the degradation rate would have been lower. Since the implementation of the 100% stroke program, Unit 1 has not experienced a sample test failure, and Unit 2 has only had two failures, both of which were due to mishandling of the snubbers during maintenance rather than age or inservice issues.

Table 1

Unit 1 Group Trending of Degradation Rate				
	Group A	Group B	Group C	Average
1st Time	4.08%	3.56%	2.72%	3.45%
2nd Time	3.43%	2.99%	1.15%	2.52%
3rd Time	0.86%	0.29%	0.91%	0.68%
4th Time	0.65%	0.00%	0.29%	0.31%

Table 2

Unit 2 Group Trending of Degradation Rate				
	Group A	Group B	Group C	Average
1st Time	6.25%	2.54%	3.94%	4.24%
2nd Time	2.40%	1.50%	2.48%	2.12%
3rd Time	1.91%	0.90%	1.42%	1.41%
4th Time	0.88%	0.44%	N/A	N/A

2.2 Plant “B”

2.2.1 Plant “B” Background

Plant B is a two-unit, four loop PWR design. It has a very large mechanical snubber population but has never implemented snubber reduction. One unit is predominantly hydraulic snubbers and the other is predominantly mechanical. After 15 cycles of operation the plant implemented a 100% stroke program of the mechanical snubbers. On one unit, one-half of the snubbers were stroked each cycle and, on the other, 25% are stroked each cycle. Thus, the population of one unit was stroked every 3 years and the other every 6 years. This schedule was maintained for another 20 years; at which time, both units were placed on the 25% or 6 year schedule.

2.2.2 Plant “B” Results

Due to multiple changes in program ownership, the historical data for Plant B are not as complete as that of Plant A. It is not a simple matter to calculate a definitive degradation rate without expending significant resources. However, it is possible to review overall data and make subjective conclusions. Plant B did have a “significant” history of failed and degraded mechanical snubbers prior to implementing the stroke program. Raw numbers clearly indicate that the number of failed mechanical snubbers has decreased over time, even if detailed cycle by cycle comparisons are not readily available. Data compiled over the last five cycles indicate that the average degradation rate is approximately 2% for both units, which subjectively represents an improvement over time.

2.3 Plant “C”

2.3.1 Plant “C” Background

Plant C is a single unit, three loop PWR design. It has a large mechanical snubber population of over 1300 snubbers. For the first 20 cycles, the snubber program consisted of visual examinations, 37 Plan sample testing, and stroking of a minimal number of snubbers. The stroked snubbers consisted of a select group of approximately 60 snubbers installed outdoors on the main steam system (which were stroked every other cycle) as well as others that may have been affected by a dynamic transient event. Near the end of those first 20 cycles, there were repeated testing failures with multiple sample expansions as a result. The failure rate for those later cycles was greater than 5%. Subsequently, a stroke program was implemented for the mechanical snubbers.

2.3.2 Plant “C” Results

The Plant “C” stroke program is designed to rotate through the entire population over four cycles. Due to the recent implementation of the program, this will be accomplished over the next several cycles. Although the entire population has yet to be stroked, the current failure rate has been reduced to 2% and is expected to improve even more as the stroke program rotations are completed.

3. Conclusion

The implementation of a Mechanical Snubber Condition Monitoring Program consisting of manually exercising (stroking) the snubbers has resulted in more reliable snubber populations in the three operating plants researched for this paper. Such programs have proven to be beneficial with regard to reducing degradation over time. The data presented herein do not address specifics related to cost effectiveness, as those determinations are site specific relative to population size and resource availability. For the sites noted, the programs were determined to be beneficial and cost effective based on the site-specific needs and existing scope. In cases where a stroke program can be justified, such a program could be utilized to increase the mechanical snubber population reliability.

Inservice Examination and Testing Issues for Dynamic Restraints (Snubbers) in Nuclear Power Plants*

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* This paper was prepared by staff of the NRC. It may present information that does not currently represent an agreed-upon NRC staff position. The NRC has neither approved nor disapproved the technical content.

Abstract

This paper discusses recent issues related to the inservice examination and testing of dynamic restraints (snubbers) at U.S. nuclear power plants. The U.S. Nuclear Regulatory Commission (NRC) staff identified these issues during its review of examination and testing snubber programs and relief requests, as well as operating experience. This discussion includes information that could apply generically to the implementation of effective snubber programs at U.S. nuclear power plants, specifically, regulatory and programmatic; and operational readiness issues of snubbers. Regulatory and programmatic issues such as inservice examination and testing of snubbers, where some of the plants did not follow correctly the requirements as specified in the American Society of Mechanical Engineers (ASME) *Boiler and Pressure Vessel Code* (BPV Code), Section XI, or ASME *Operation and Maintenance of Nuclear Power Plants*, Division 1, OM Code: Section IST (OM Code); some plants when using the OM Code Case OMN-13, “Performance Based Requirements for Extending Visual Examination Interval at Light Water Reactor (LWR) Power Plants,” did not follow the specified requirements during the snubbers’ extended visual examination interval of once in ten years; and some plants did not correctly implement the service life monitoring (SLM) program requirement to reevaluate service life of snubbers every refueling outage. Also, this paper discusses the operating experience (OE) related to steam generators snubber leakage at various nuclear power plants.

Introduction

The U.S. Nuclear Regulatory Commission (NRC) staff has encountered a number of snubber inservice examination and testing issues since the last paper presented at the Thirteenth American Society of Mechanical Engineers (ASME)/NRC Symposium on Pumps, Valves, and Inservice Testing in 2017. This paper discusses:

(1) **Regulatory and Programmatic Issues:**

- Inservice Examination and Testing of Snubbers – ASME *Boiler and Pressure Vessel Code* (BPV Code), Section XI, or ASME *Operation and Maintenance of Nuclear Power Plants,* Division 1, OM Code: Section IST (OM Code).

- Use of the ASME OM Code Case OMN-13, "Performance Based Requirements for Extending Visual Examination Interval at LWR Power Plants," and records of all the visual examination failures during this extended 10-year interval.

- Service Life Monitoring (SLM) programs for snubbers.

(2) **Snubber Operational Readiness Issues:**

- Operating Experience (OE) related to steam generator (SG) snubbers at various nuclear power plants.

    - Comanche Peak Nuclear Power Plant – Non-Cited Violation Unit 2 SG Snubber Leakage.

    - Armenian Nuclear Power Plant Unit 2 – SG Snubber Leakage.

- OE related to Arkansas Nuclear One Unit 2 (ANO2) - Pressurizer Line Snubber failures.

This discussion includes information that could have generic applicability in the implementation of effective inservice examination and testing snubber programs at U.S. nuclear power plants.

Inservice Examination and Testing of Snubbers – ASME BPV Code, Section XI, or ASME OM Code

Background

- ASME BPV Code, Section XI, 2005 Addenda and earlier Editions and Addenda, contained the snubber inservice examination and testing requirements.
- ASME BPV Code, Section XI, 2006 addenda through the latest edition, do not contain the snubber inservice and testing requirements.
- ASME BPV Code, Section XI, IWF-1220, Endnote 39, states that snubber examination and test requirements can be found in the ASME OM Code.
- ASME OM Code, 1995 Edition through the latest Edition, contain the snubber inservice and testing requirements.
  Boundary between Snubber (pin-to-pin) and support structure Figure 1300-1(f), ASME BPV Code, Section XI, 2006 Addenda and later Editions.

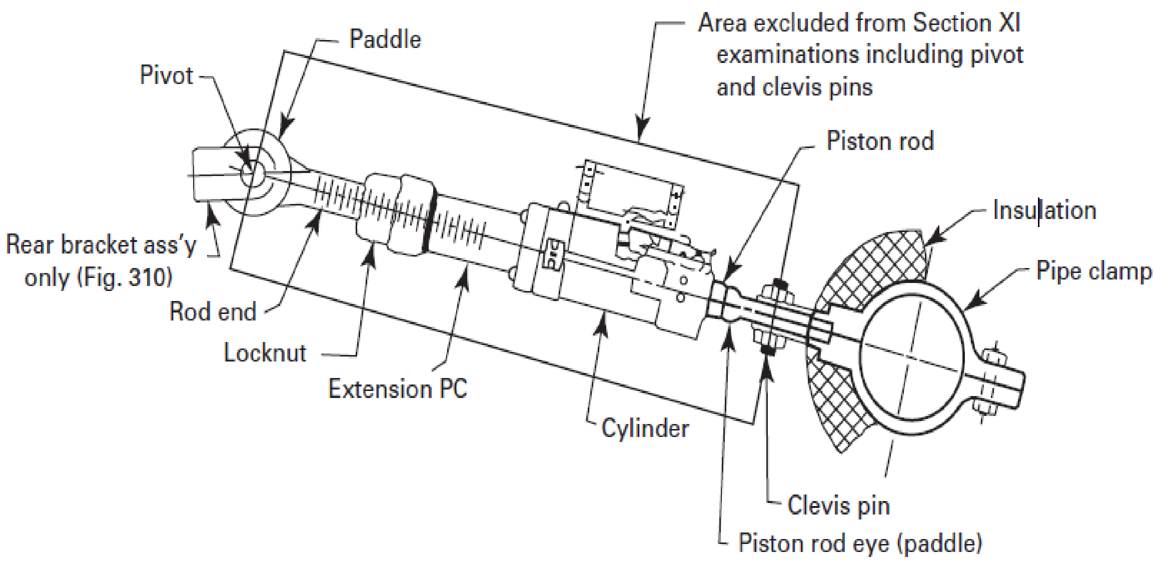


Figure 1300-1(f)

Regulation

- Paragraph (g) in Section 55a, "Codes and Standards," in Part 50, "Domestic Licensing of Production and Utilization Facilities," of Title 10, "Energy," in the *Code of Federal Regulations* (10 CFR 50.55a(g)) states, in part, that inservice inspection (ISI) of components (including supports) which are classified as ASME BPV Code Class 1, Class 2, and Class 3 must meet the requirements, set forth in Section XI of editions and addenda of the ASME BPV Code (or ASME OM Code for snubbers).
- 10 CFR 50.55a(g)(4)(ii) requires the use of the latest edition of the ASME BPV Code, Section XI and addenda that have been incorporated by reference 18 months prior to the beginning of each 120-month inspection interval. This Code is considered to be the "Code of Record" for the inspection interval.
- 10 CFR 50.55a(b)(3)(v)(A), "Snubbers, First provision," states, in part, that licensees may use Subsection ISTD of the ASME OM Code, 1995 Edition through the latest edition incorporated by reference, in place of the requirements for snubbers in the editions and addenda up to the 2005 addenda of the ASME BPV Code, Section XI.
- 10 CFR 50.55a(b)(3)(v)(B), "Snubbers, Second provision," states, in part, that licensees must comply with the provisions for examining and testing snubbers in Subsection ISTD of the ASME OM Code when using the 2006 Addenda and later editions of Section XI of the ASME BPV Code.

NRC Recommendation

- If a plant's "Code of Record" for ISI interval is ASME BPV Code, Section XI, 2006 Addenda or later, the licensee must use the applicable edition of the ASME OM Code for developing its snubber program.
- The regulation requires that the snubber program should be updated and aligned with the plant's 10-year ISI interval.
- While using ASME OM Code, many licensees have aligned their snubber program with their 10-year inservice testing (IST) program. NUREG-1482, "Guidelines for Inservice Testing at Nuclear Power Plants," describes a method to align the snubber program with IST program.
- Snubber program alignment with the ISI or IST 10-year interval should be clearly specified in the snubber program, along with start and end dates.
- Snubber Program alignment with the IST 10-year interval in lieu of the ISI 10-year interval should be carefully evaluated, and any extension beyond the requirements of ASME OM Code, ISTA-3120, or ASME BPV Code, Section XI, IWA-2430, must be submitted as a relief request to NRC for approval before implementation.
- Snubber Program plan and its 10-year updates must be submitted to NRC as required by ISTA-3200.
- While using the ASME OM Code for inservice examination and testing of snubbers (pin-to-pin), the examination of support structure and attachments must be performed by use of ASME BPV Code, Section XI, as described in Figure 1300-1(f).

Use of ASME OM Code Case OMN-13, and Records of All Visual Examination Failures during Extended 10-Year Interval

Background

- ASME OM Code Case OMN-13 establishes specific requirements that must be met in order to allow extension of the visual examination interval beyond the maximum interval allowed in ASME OM Code, Table ISTD-4252-1, for snubbers and up to 10 years.
- ASME OM Code Case OMN-13, Section 3.7(a), "Frequency of Examinations," states that all snubbers within the scope of ASME OM Code, Subsection ISTD, shall be examined and evaluated per this Code Case at least once every 10 years.
- ASME OM Code Case OMN-13 does not provide any grace period beyond 10 years.
- ASME OM Code Case OMN-13, Section 3.7(b), states that if at any time during an examination interval the cumulative number of unacceptable snubbers exceeds the applicable value from Column B in Table ISTD-4252-1, the current examination interval (10-years) shall end.

Issues

- NRC staff learned that while implementing Code Case OMN-13, some plants are not keeping records of their failures of snubber visual examinations and failures discovered during maintenance, snubber replacement, water hammer event, reservoir fluid level low, and service life monitoring during the 10-year extension. Therefore, plants do not have any justification available to continue using Code Case OMN-13.
- NRC staff also learned that some plants are continuing to use Code Case OMN-13 in the subsequent interval without updating to the current applicable revision of Code Case

OMN-13, and without any document or record showing that they meet the failure requirements of Table ISTD-4252-1 specified in Section 2(b).

Discussion

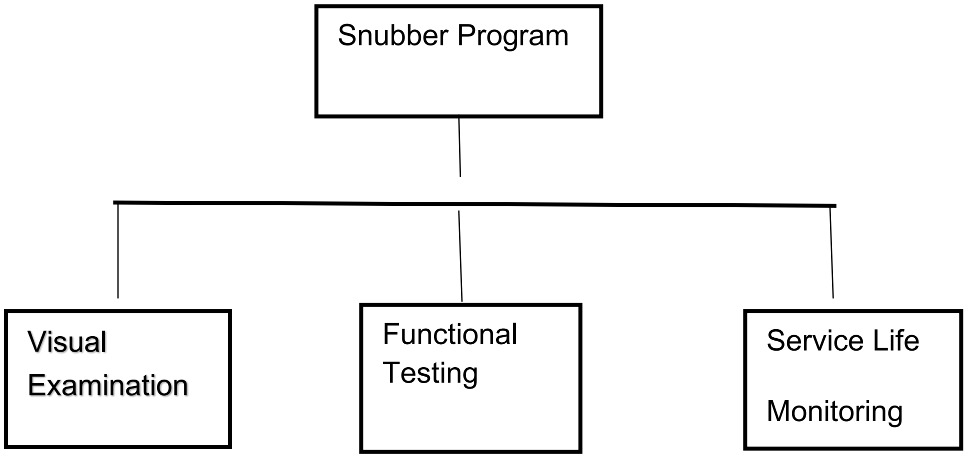
- Code Case OMN-13, Revision 2, Section 2(b), states that the requirements of this Code Case shall be implemented after the requirements of ASME OM Code, paragraphs ISTD-4251 and ISTD-4252, have been satisfied and the previous examination per Table ISTD-4252-1 was performed at a maximum interval of two fuel cycles.
- Code Case OMN-13, Revision 2, Section 3.7(a), states that all snubbers within the scope of ASME OM Code, Subsection ISTD, shall be examined and evaluated per this Code Case at least once every 10 years.
- Code Case OMN-13, Revision 2, Section 3.7(b), states, in part, that
    - If at any time during an examination interval the cumulative number of unacceptable snubbers exceeds the applicable value from Column B in Table ISTD-4252-1, the current examination interval shall end, and all remaining examinations must be completed within the current fuel cycle.
    - Examples of the Cumulative number of unacceptable visual exams failures found during the 10-year extension:
        - Visual Examination = A
        - During Maintenance = B
        - During SLM = C
        - During Walkdowns = D
        - Due to low fluid level = E
        - During testing = F
    - If any time the total number of cumulative of unacceptable visual exams for snubbers (A+B+C+D+E+F) exceeds the applicable value from Column B in Table ISTD-4252-1, the current examination interval shall end.

NRC Recommendation

- While using Code Case OMN-13, the General Requirements, Section 2(b), must be met for two fuel cycles (48 months) and continue to meet the examination failures requirements as specified in ASME OM Code, Table ISTD-4252-1.
- While using Code Case OMN-13, if at any time during the 10-year extension, the cumulative number of examination failures exceed the number of failures specified in Table ISTD-4252-1, the use of the Code Case must end.
- While using Code Case OMN-13, and after completing the 10-year extension allowed by OMN-13, if the licensee wants to continue to use the Code Case in the subsequent 10-year ISI/IST interval, the plant must document that all cumulative examination failures (in previous 10-year extension) satisfy the total number failures requirement of Table ISTD-4252-1.

Service Life Monitoring Programs for Snubbers

Snubber Program contains all three key elements as follows:



Background

- Generic Letter (GL) 80-99, "Technical Specification Revisions for Snubber Surveillance," requires that all snubbers in the scope listed in technical specification (TS) shall meet the requirements of snubber inservice (1) visual examination; (2) functional testing; and (3) SLM as specified in the TS. SLM requires that the service life of each snubber shall be established and recorded every refueling outage. If the indicated service life will be exceeded prior to the next scheduled snubber service life review, the snubber service life shall be re-evaluated or the snubber shall be replaced or re-conditioned so as to extend its service life beyond the date of the next scheduled service life review.
- ASME OM Code, Subsection ISTD, requires that all snubbers in the scope shall meet the requirements of snubber inservice (1) visual examination (paragraph ISTD-4200); (2) functional testing (paragraph ISTD-5200); and (3) SLM (paragraph ISTD-6000). The ISTD-6100 requires that initial snubber service life shall be predicted based on manufacturer's recommendation or design review. ISTD-6200 requires that the service life for each location where a snubber is installed shall be re-evaluated at least once each fuel cycle. Re-evaluation shall be based on examination, maintenance, performance, and operating service-life history data associated with representative snubbers that have been in service in the plant, as well as other information related to service life.
- Based on snubber aging study information discussed in NUREG/CR-5870, "Results of LWR Snubber Aging Research," dated May 1992, the NRC recommended the inclusion of SLM of snubbers in addition to the statistical testing process. Subsection ISTD of the ASME OM Code included SLM along with snubber inservice examination and testing requirements. Most licensees have included some reference to SLM in their existing programs.

Issues

- NRC staff learned that while developing the snubber program, some of the plants are not implementing SLM as described in the ASME OM Code, Subsection ISTD. Some of the

plant owners consider that simply fulfilling (1) visual examination and (2) functional testing requirements complete the snubber program.
- NRC staff also learned that some of the plants are not evaluating the service life of snubbers every refueling outage as required by the OM Code, paragraph ISTD-6000.
- Some plants updated snubber programs often simply reference plant procedures for snubber examinations and testing without providing any references to the applicable SLM section of the OM Code, ISTD-6000.

Discussion

- SLM is the key element of the snubber program along with snubber inservice (1) visual examination and (2) functional testing requirements as specified by GL 80-99 and ASME OM Code, Subsection ISTD. SLM requires that service life of each installed snubber shall be re-evaluated once each fuel cycle. Re-evaluation shall be based on the vendor's recommendation, examination, maintenance, performance, and operating service-life history data associated with representative snubbers that have been in service in the plants.
- NRC staff observed that during 2014 visual examination of snubbers at five nuclear plants' refueling outages, a large number of mechanical snubbers were failed. NRC staff discovered that most of these snubber failures were determined to be caused by grease degradation, such as: (1) oil separation from grease; (2) dried or "caked" grease; (3) excessive grease; (4) sticky and tacky grease; and (5) hardened or missing grease. NRC issued Information Notice (IN) 2015-09, "Mechanical Dynamic Restraint (Snubber) Lubricant Degradation Not Identified due to Insufficient Service Life Monitoring." A well-planned SLM program for snubbers would have minimized or eliminated the number of snubber failures due to degradation of grease.
- The SLM program is the primary instrument for assuring continued reliability of a snubber population at a plant. The statistical method of sample testing provides point-in-time assessment of population functionality but, in general, does not serve as an effective tool to either maintain or improve reliability. This is due to the fact that such functional testing is based on small samples (10% or 37 snubbers) on a periodic basis, and is not predictive in nature.
- Licensees are responsible for establishing, maintaining, and implementing an SLM program for all the snubbers in the scope of 10 CFR 50.55a(g) to optimize and supplement (1) ISTD-4200, "Visual Examination," which is performed only once in 24 months, or 48 months or 10 years (if Code Case OMN-13 is used) based upon plant performance, and (2) ISTD-5200, "Operational Testing," which is performed on only 10 percent of selected snubbers or 37 snubbers or once in 10 years (if Code Case OMN-15 is used based on performance). Details are summarized in the following table:

Snubber Program (Note 2)				
Visual Examination		Functional Test		Service Life Monitoring
Use of ISTD-4200 Requirements	Optional Use of OMN-13 for visual examination extension (Note 1)	Use of ISTD-5200 Requirements	Optional Use of OMN-15 for functional test extension (Note 1)	Use of ISTD-6000 Requirements
Visual examination of all the snubbers once in 24 months or 48 months	OMN-13 not used	Functional Test of only 10% or 37 snubbers every refueling outage	OMN-15 not used	Service life reevaluation of all the snubbers in the scope once every refueling outage
Visual examination of all the snubbers once in 10 years	OMN-13 used	Functional Test of only 10% or 37 snubbers every refueling outage	N/A (Note 1)	Service life reevaluation of all the snubbers in the scope once every refueling outage
Visual examination of all the snubbers once in 24 months or 48 months	N/A (Not 1)	Functional test of snubbers could be extended up to once in 72 months as allowed by OMN-15	OMN-15 used	Service life reevaluation of all the snubbers in the scope once every refueling outage
Note 1: Code Case OMN-13 and OMN-15 cannot be used together. Note 2: (a) Snubber visual examination could be only once in 24 months or 48 months or 10 years, with functional test of 10% or 37 snubbers; or (b) snubber visual examination once in 24 months or 48 months, with functional test extended up to once in 72 months. SLM which is only performed every refueling outage (24 months) is the key element of snubber program				

NRC Recommendation

- The licensees must develop the SLM program as part of the snubber program as defined in the ASME OM Code, paragraph ISTD-6000, or in accordance with an approved alternative or relief request. SLM must consider all the vendor recommendations, maintenance record data available for snubbers while evaluating or re-evaluating the service life. Service Life of all the snubbers must be re-evaluated every refueling outage. Nonmandatory Appendix F, “Dynamic Restraints (Snubbers) Service Life Monitoring Methods,” of Subsection ISTD provides additional guidance in developing a SLM Program. For more details, see Non-Mandatory Appendix F of the ASME OM Code.

- The SLM program shall be based on the snubber manufacturer’s recommendation, operating environment, snubber design limits, snubber type (mechanical or hydraulic), modification and maintenance history, and test records of snubbers.
- The SLM program in the snubber program is the key element for assuring continued reliability of a snubber population at a plant. Program documentation is expected to provide information regarding specific SLM requirements and how the requirements are satisfied.
- The records of all activities (i.e., repair, replacements, maintenance, corrective action work, failures, etc.) related to all snubbers must be documented and considered with the vendor’s recommendations for the SLM program.

OE related to Steam Generator (SG) Snubbers at Various Nuclear Power Plants

Comanche Peak Nuclear Power Plant – Non-Cited Violation Unit 2 SG Snubber Leakage

Background

- NRC - Inspection Report - Non-Cited violation related to SG snubbers leaking and their Operability Determination and Functionality Assessments at Comanche Peak Nuclear Power Plant (Comanche Peak).
- Comanche Peak Unit 2 committed to ASME OM Code, Subsection ISTD, for snubber inservice examination and testing.
- During NRC Inspection activities between July 1 and September 30, 2017, one of the findings was repetitive and related to Comanche Peak Unit 2 loop 3 SG hydraulic snubber’s low level fluid in its reservoir.

Findings

- The NRC inspector identified a finding of low safety significance and associated Non-Cited Violation (NCV) of 10 CFR Part 50, Appendix B, Criteria XVI, “Corrective Action,” associated with the licensee’s failure to take timely corrective actions for a condition adverse to quality.
- Licensee failed to take corrective actions multiple times for a repetitive leak in the hydraulic snubbers for Unit 2, loop 3 SG, resulting in the level in the hydraulic fluid reservoir to fall below the minimum level in the sight glass on multiple occasions.

Description

- On March 9, 2017, the licensee discovered that Unit 2 SG 2-03 upper hydraulic snubber oil reservoir oil level was low.
- The licensee documented this deficiency in CR-2017-003019 and closed this Condition Report (CR) after completion of a work order to fill reservoir without any detailed evaluation.

- The licensee continued operation by considering that the Unit 2 loop 3 SG snubber was no longer required by referencing an earlier letter issued by Westinghouse in 2007 following a leak from Unit 2 loop 4 SG snubbers.
- The Westinghouse 2007 letter stated that Unit 2 could be operated for the remainder of the cycle, but the licensee needed to perform a detailed analysis to support this. The letter also stated that an analysis could likely be performed to justify removal of the Unit 2 snubbers, based on an analysis that was performed for the replacement of Unit 1 SGs.
- Although the Westinghouse letter had only documented acceptability for the existing cycle (2007), the licensee began using this letter as a justification for operability for snubber oil leaks well past that time frame, and did not perform an analysis to justify continued operation with degraded SG snubbers.
- In an operability evaluation prior to 2014, the licensee had only justified continued operation with a degraded snubber until the oil could be refilled.
- Starting in 2014, the licensee began stating in the operability evaluations that the SGs were operable because the snubbers were not required. Although the 2007 Westinghouse letter only concluded that an analysis to justify removing the snubbers could be performed, the licensee considered the ability to potentially perform the analysis as equivalent to having an analysis, without performing the analysis.
- On May 10, 2017, Unit 2 was restarted with low fluid level with no action taken to correct the condition.
- On May 30, 2017, the licensee discovered that the reservoir was empty, documented this in CR-2017-006871, and closed this CR with no additional action based on the continuing assumption that the snubber was not required, and the low reservoir level was not required to be corrected.
- While closing CR-2017-006871, the licensee did not perform the detailed evaluation to support operating with the degraded snubber as specified by Westinghouse in the 2007 letter.
- The NRC inspector discovered that a prior instance of an empty reservoir had existed in 2014, and had not been corrected until 2015. The inspector discussed this issue with the licensee and questioned the operability of the SG with degraded snubbers.
- On June 17, 2017, the licensee completed the work order to fill the snubber reservoir. The licensee generated CR-2017-009071 documenting that snubbers were leaking and that it was a degraded condition requiring corrective action.

Analysis

- The licensee failed to take corrective actions for a leak in the SG hydraulic snubbers, resulting in the fluid level reservoir falling below the minimum level on multiple occasions.
- The licensee’s failure to take timely and adequate corrective actions to correct a condition adverse to quality was a performance deficiency.
- The NRC inspector determined that the licensee did not perform the detailed evaluation to support operating with the degraded Unit 2 snubber as proposed by the Westinghouse 2007 letter for Unit 1.

Armenian Nuclear Power Plant Unit 2 –SG Snubber Leakage

Background

- Armenian Nuclear Power Plant (NPP) Unit 2, Leaking Hydraulic SG Snubber Caused a Plant Shutdown – Presentation by Armenian NPP at International Atomic Energy Agency (IAEA), Vienna, Austria, October 8-11, 2018.
- On March 24, 2018, operators at Armenian NPP Unit 2 received an alarm for low oil level in the SG hydraulic snubber (HS-6/6) on the primary circuit.
- Initial inspection of SG snubber did not identify any visible damage and obvious leakage of oil from the SG snubber and its tank (reservoir), but oil was added into the snubber HS-6/6 tank (reservoir).
- Additional visual inspection of snubber HS-6/6, about an hour later, revealed oil leakage along the piston of the snubber at a rate of about one drop per 4 seconds (15 drops per minute).
- Unit 2 was shutdown for about 67 hours to complete the repair of SG snubber.

Findings

- The cause of the hydraulic oil leak in HS-6/6 snubber was determined to be premature degradation of the O-ring installed in 2017.
- Degradation of the O-ring appeared to be the result of poor quality of rubber material used in the O-ring provided by vendor.

Corrective Action

- The owner replaced all HS-6/6 SG hydraulic snubber rubber O-rings.
- The owner checked selectively the condition of rubber O-rings in the rest of the 5 SG hydraulic snubbers, which were repaired during the 2017 outage.
- The owner is working with the vendor to determine likely causes of the premature embrittlement of the O-ring material.

Arkansas Nuclear One Unit 2 (ANO2) –Pressurizer Line Snubber Failures

Background

- NRC Inspection Report for ANO – Integrated Inspection Report 05000313/2020002 and 05000368/2020002, dated August 5, 2020.

Findings

- The NRC inspector identified a finding of low safety significance and associated Non-Cited Violation (NCV) of 10 CFR Part 50, Appendix B, Criteria XVI, “Corrective Action,” associated with the licensee’s failure to take timely corrective actions for a condition adverse to quality.

Description

- During the 2020 ANO Unit 2 spring refueling outage, a hydraulic snubber, 2CCA-15-H60, was found fully disconnected on the reactor building floor during an initial walkdown.
- During walkdowns to identify the source of the disconnected snubber 2CCA-15-H60, another snubber 2CCA-13-H4 was also identified as disconnected at the pipe clamp. The snubber remained within the degraded pipe clamps, but the load pin could not be located.
- This condition prompted the licensee to complete a stress analysis to assure that the structural integrity of the piping system remained within design.
- The licensee concluded that after snubber 2CCA-13-H4 lost its load pin at the pipe clamp, the added vibration experienced in the system resulted in the failure of snubber 2CCA-15-H60.
- A review of past maintenance history revealed that in 2009, snubber 2CCA-13-H4 had been visually examined (VT-3) twice during maintenance activities per Work Order 51667491.
- The NRC inspectors concluded that no additional corrective actions (i.e., condition reports, work orders, evaluations, etc.) had been taken subsequent to the second VT-3 examination of snubber 2CCA-13-H4.

Corrective Action

- In the spring of 2020, the licensee replaced snubber 2CAA-13-H4 along with snubber 2CAA-15-H60, and repaired the degraded pipe clamps.

Analysis

- The licensee failed to take corrective actions for degraded snubber 2CAA-13-H4 during 2009 refueling outage.
- The NRC staff reviewed and concluded that this degraded Hydraulic Snubber 2CAA-13-H4 should have been repaired or replaced in 2009 However, in 2009, the licensee's evaluation concluded that this degraded snubber was functional and acceptable.

Conclusion

The purpose of this paper is to make licensees aware of the snubber inservice examination and testing issues that the NRC staff has encountered since the Thirteenth NRC/ASME Symposium on Pumps, Valves, and Inservice Testing in 2017. Licensees who believe that some of the items discussed apply to their facilities may wish to review their current inservice examination and testing programs for snubbers, and modify or update their programs, as appropriate.

Acknowledgements

I would like to thank my senior colleagues Thomas Scarbrough and Robert Wolfgang for reviewing this paper and providing valuable input.

References

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2. *U.S. Code of Federal Regulations*, "Domestic Licensing of Production and Utilization Facilities," Part 50, Chapter I, Title 10, "Energy," Section 50.55a, "Codes and standards."

3. NRC, NUREG-1482, Revision 3, "Guidelines for Inservice Testing at Nuclear Power Plants: Inservice Testing of Pumps and Valves and Inservice Examination and Testing of Dynamic Restraints (Snubbers) at Nuclear Power Plants -Final Report," Revision 3, 2020.

4. ASME *Boiler and Pressure Vessel Code*, Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components," New York, NY.

5. ASME, *Operation and Maintenance of Nuclear Power Plants,* Division 1, OM Code: Section IST, New York, NY.

6. NUREG/CR-5870, "Results of LWR Snubbers Aging Research," dated May 1992, (ADAMS Accession No. ML040340438).

7. Comanche Peak Nuclear Power Plant – NRC Integrated Inspection Report, (ADAMS Accession No. ML17300B401).

8. Arkansas Nuclear One (ANO) – Integrated Inspection Report 05000313/2020002 and 05000368/2020002 , dated August 5, 2020 (ADAMS Accession No. ML20218A442).

IST Risk Implementation

Track Chair: Craig D. Sellers, Member ASME OM Committee

Alternative Treatments for 10 CFR 50.69

Jennifer Varnedoe
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Pressurized Water Reactor Owners Group

Acronyms:

AP-913: Institute of Nuclear Power Operations Equipment Reliability Process Description

API: American Petroleum Institute

AT: Alternative Treatment

BWROG: Boiling Water Reactor Owners Group

EPRI: Electric Power Research Institute

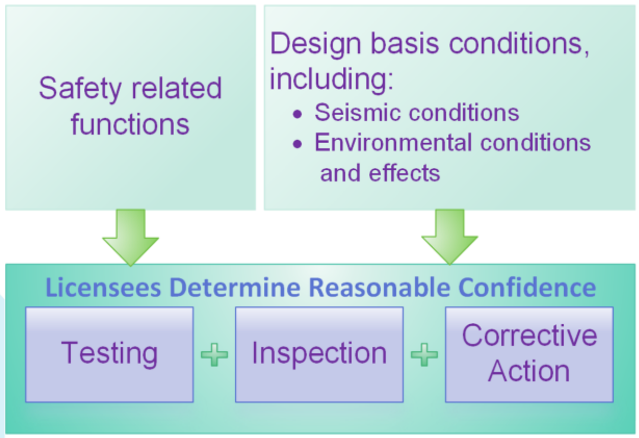
NEI: Nuclear Energy Institute

PWROG: Pressurized Water Reactor Owners Group

RISC-3: Safety-Related SSC with Low Safety Significance

SSCs: Structures, Systems, and Components

Requirements of 10 CFR 50.69 Section (d)(2)



Consistent Approaches Already Published in the Industry

- **Multiple EPRI documents from original implementation**
- **NEI 17-05 "Risk Informed Engineering Programs (10 CFR 50.69): RISC-3 Alternative Treatments**
  - Framework for identifying and implementing potential alternative treatments
  - Adequate treatments
  - Consistency
  - Maximizing benefit
  - Templates/examples
  - Integration of existing processes
  - Sharing resources
- **PWROG/BWROG have developed AT considerations to drive consistency**

Process Overview

- **Establish Corporate or Site Team, as needed**
- **Identify RISC-3 SSCs**
- **Identify safety related functional design requirements**
- **Identify and evaluate existing site activities**
- **Develop alternative treatment**
  - Considerations include using modern technology for example artificial intelligence (e.g., predictive monitoring), digital equipment, modern component design, modern materials
- **Develop technical justification against Section (d)(2) language**
- **Integrate alternative treatment into <u>existing</u> site processes**

Alternative Treatment Activity Areas

General Alternative Treatments

Regulatory Oversight and Compliance	**Quality Assurance Programmatic Requirements**
Corrective Maintenance	**Monitoring and Reporting**

Same basis for all RISC-3

Component Specific Alternative Treatments

Design and Procurement
Maintenance Strategy

AT application will vary by component types and functions

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Component Specific Alternative Treatments

Design and Procurement

- **Evaluated through configuration control**
- **Design and procurement requirements must meet the needs of the function.**
- **Non-nuclear specific industrial standards can be used to address quality and design basis conditions.**
  - Example: API (e.g., for valves)

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Procurement and Design Considerations

- **Operating Experience**
- **Component Failure Modes**
- **Applicability of non-Nuclear Industry Standards**
  - Material quality
  - Testing requirements
- **Vendor selection**
  - Vast majority of RISC-3 components are purchased from existing nuclear suppliers
  - Provides an increased selection of components to examine from existing nuclear suppliers
  - Decrease lead time and increase parts availability of components
- **PWROG/BWROG have developed considerations to drive consistency**

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Component Specific Alternative Treatments

Maintenance Strategy

- Inspection and testing requirements should be integrated into the SSC maintenance strategy.
- AP-913 process and Value Based Maintenance should be used to re-evaluate the strategy with Paragraph (d)(2) requirements.
- Tech Spec requirements remain unchanged

Inspection and Testing Alternative Treatment Considerations

- **Operating Experience**
- **Component Failure Modes**
- **Effectiveness of Inspection and Testing Methods**
  - Detecting Failure
  - Detecting Degradation
- **Frequency of Inspections and Testing**
  - Dependence on effectiveness of activities
  - Insights from EPRI Preventive Maintenance Tools
  - Insights from plant-specific Preventive Maintenance Program
- **PWROG/BWROG have developed considerations to drive consistency**

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Operating Experience and Lessons Learned

- **Joint industry operating experience and lessons learned through the following organizations including:**
  - PWROG
  - BWROG
  - EPRI
  - NEI

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Questions

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Alternative Treatments for 10 CFR 50.69 – ASME/NRC OM Code Symposium – January 2022

NRC Staff 10 CFR 50.69 Knowledge Transfer Activities*

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* This paper was prepared by staff of the U.S. Nuclear Regulatory Commission. It may present information that does not currently represent an agreed-upon NRC staff position. NRC has neither approved nor disapproved the technical content.

Abstract

The staff of the U.S. Nuclear Regulatory Commission (NRC) has implemented knowledge transfer activities to provide information for NRC inspectors and engineers regarding Section 69, “Risk-informed categorization and treatment of structures, systems and components for nuclear power reactors,” in Part 50, “Domestic Licensing of Production and Utilization Facilities,” of Title 10, “Energy,” in the Code of Federal Regulations (10 CFR 50.69, referred to herein as 50.69). For example, the staff has conducted training sessions in each of the NRC Region offices and its headquarters facility to describe (1) the history of 50.69, (2) the Commission direction regarding 50.69 in Federal Register notice 69 FR 68008, dated November 22, 2004, (3) the inspection requirements and guidance in NRC Inspection Procedure (IP) 37060, “10 CFR 50.69 Risk-Informed Categorization and Treatment of Structures, Systems, and Components Inspection,” (4) the implementation and results of the initial 50.69 inspections, and (5) regulatory activities related to nuclear power plant licensees who are implementing 50.69 programs. This paper discusses the ongoing knowledge transfer activities for NRC inspectors and engineers for the evaluation of the treatment of structures, systems, and components during the implementation of 50.69 at operating nuclear power plants.

I. Introduction

The staff of the U.S. Nuclear Regulatory Commission (NRC) has implemented knowledge transfer activities to provide information for NRC inspectors and engineers regarding Section 69, “Risk-informed categorization and treatment of structures, systems and components for nuclear power reactors,” in Part 50, “Domestic Licensing of Production and Utilization Facilities,” of Title 10, “Energy,” in the *Code of Federal Regulations* (10 CFR 50.69, referred to herein as 50.69). For example, the staff has conducted training sessions in each of the NRC Region offices and its headquarters facility to describe (1) the history of 50.69; (2) the Commission direction regarding 50.69 in *Federal Register* notice 69 FR 68008, dated November 22, 2004; (3) the inspection requirements and guidance in NRC Inspection Procedure (IP) 37060, “10 CFR 50.69 Risk-Informed Categorization and Treatment of Structures, Systems, and Components Inspection;” (4) the implementation and results of the initial 50.69 inspections, and (5) regulatory activities related to nuclear power plant licensees who are implementing 50.69 programs. This paper discusses the ongoing knowledge transfer activities for NRC inspectors and engineers for the evaluation of the treatment of structures, systems, and components (SSCs) during the implementation of 50.69 at operating nuclear power plants.

II. 10 CFR 50.69 Requirements

A nuclear power plant licensee or applicant may request implementation of 10 CFR 50.69 for risk-informed treatment of SSCs as an alternative to certain special treatment requirements (STRs) in the NRC regulations.

The NRC regulations in 50.69(a) define each risk-informed safety class (RISC) of SSCs as follows:

RISC-1 SSCs: safety-related SSCs that perform safety significant functions.

RISC-2 SSCs: nonsafety-related SSCs that perform safety significant functions.

RISC-3 SSCs: safety-related SSCs that perform low safety significant functions.

RISC-4 SSCs: nonsafety-related SSCs that perform low safety significant functions.

Paragraph (a) in 50.69 defines a safety significant function as a function whose degradation or loss could result in a significant adverse effect on defense-in-depth, safety margin, or risk.

If the 50.69 license amendment is approved, paragraph (b) in 50.69 specifies that the licensee or applicant may voluntarily comply with the requirements in 50.69 as an alternative to compliance with the following requirements for RISC-3 and RISC-4 SSCs (as specified in 50.69):

(i) 10 CFR Part 21.

(ii) The portion of 10 CFR 50.46a(b) that imposes requirements to conform to Appendix B to 10 CFR Part 50.

(iii) 10 CFR 50.49..

(iv) 10 CFR 50.55(e).

(v) The inservice testing requirements in 10 CFR 50.55a(f); the inservice inspection, and repair and replacement (with the exception of fracture toughness), requirements for ASME Class 2 and Class 3 SSCs in 10 CFR 50.55a(g); and the electrical component quality and qualification requirements in Section 4.3 and 4.4 of IEEE 279, and Sections 5.3 and 5.4 of IEEE 603–1991, as incorporated by reference in 10 CFR 50.55a(h).

(vi) 10 CFR 50.65, except for paragraph (a)(4).

(vii) 10 CFR 50.72.

(viii) 10 CFR 50.73.

(ix) Appendix B to 10 CFR Part 50.

(x) The Type B and Type C leakage testing requirements in both Options A and B of Appendix J to 10 CFR Part 50, for penetrations and valves meeting the following criteria:

(A) Containment penetrations that are either 1-inch nominal size or less, or continuously pressurized.

(B) Containment isolation valves that meet one or more of the following criteria:

(*1*) The valve is required to be open under accident conditions to prevent or mitigate core damage events;

(*2*) The valve is normally closed and in a physically closed, water-filled system;

(*3*) The valve is in a physically closed system whose piping pressure rating exceeds the containment design pressure rating and is not connected to the reactor coolant pressure boundary; or

(*4*) The valve is 1-inch nominal size or less.

(xi) Appendix A to Part 100, Sections VI(a)(1) and VI(a)(2), to the extent that these regulations require qualification testing and specific engineering methods to demonstrate that SSCs are designed to withstand the Safe Shutdown Earthquake and Operating Basis Earthquake.

Paragraph (d)(1) in 50.69 specifies the following requirements for the treatment of RISC-1 and 2 SSCs:

> The licensee or applicant shall ensure that RISC-1 and RISC-2 SSCs perform their functions consistent with the categorization process assumptions by evaluating treatment being applied to these SSCs to ensure that it supports the key assumptions in the categorization process that relate to their assumed performance.

Paragraph (d)(2) in 50.69 specifies the following requirements for the treatment of RISC-3 SSCs:

> The licensee or applicant shall ensure, with reasonable confidence, that RISC-3 SSCs remain capable of performing their safety-related functions under design-basis conditions, including seismic conditions and environmental conditions and effects throughout their service life. The treatment of RISC-3 SSCs must be consistent with the categorization process. Inspection and testing, and corrective action shall be provided for RISC-3 SSCs.
>
> (i) Inspection and testing. Periodic inspection and testing activities must be conducted to determine that RISC-3 SSCs will remain capable of performing their safety-related functions under design-basis conditions; and
> (ii) Corrective action. Conditions that would prevent a RISC-3 SSC from performing its safety-related functions under design-basis conditions must be corrected in a timely manner. For significant conditions adverse to quality, measures must be taken to provide reasonable confidence that the cause of the condition is determined and corrective action taken to preclude repetition.

Paragraph (e) in 50.69 specifies requirements for feedback and process adjustment based on the specific RISC-1, 2, 3, or 4 classifications. Paragraph (f) specifies requirements for program documentation, change control and records. Paragraph (g) specifies reporting requirements for RISC-1 and RISC-2 SSCs.

III. 10 CFR 50.69 Guidance

In the *Federal Register* notice 69 FRN 68008 for the 10 CFR 50.69 rule, the Commission provides guidance for implementing 50.69 at nuclear power plants. In the FRN, the Commission states that prescriptive requirements as to how licensees are to treat specific SSCs (e.g., safety-related) are referred to as "special treatment requirements." As noted in the FRN, the STRs are developed to provide greater assurance that SSCs will perform their functions under particular conditions with high quality and reliability. The STRs include particular examination techniques, testing strategies, documentation requirements, personnel qualification requirements, and independent oversight. The distinction between treatment and special treatment is the degree of NRC specification as to what must be implemented for particular SSCs or conditions. See 69 FR 68008.

In the FRN, the Commission provided an overview of the 50.69 requirements. In particular, 50.69 represents an alternative set of requirements whereby a licensee or applicant may voluntarily undertake categorization of its SSCs consistent with the requirements in 50.69(c), remove the STRs listed in 50.69(b) for SSCs that are determined to be of low individual safety significance, and implement alternative treatment requirements in 50.69(d). The regulatory requirements not removed by 50.69(b) continue to apply as well as the requirements specified in 50.69. The rule contains requirements by which a licensee categorizes SSCs using a risk-informed process, adjusts treatment requirements consistent with the relative significance of the SSC, and manages the process over the lifetime of the plant. See 69 FR 68008.

To implement the 50.69 requirements, a risk-informed categorization process is employed to determine the safety significance of SSCs and place the SSCs into one of four RISC categories. The determination of safety significance is performed by an integrated decision-making process which uses both risk insights and traditional engineering insights. The safety functions include both the design-basis functions (derived from the ''safety-related'' definition, which includes external events), as well as, functions credited for severe accidents (including external events). Treatment for the SSCs is required to be applied as necessary to maintain functionality and reliability, and is a function of the category into which the SSC is categorized. Finally, assessment activities are conducted to make adjustments to the categorization and treatment processes as needed so that SSCs continue to meet applicable requirements. The rule contains requirements for obtaining prior NRC review and approval of the categorization process and for maintaining certain plant records and reports. See 69 FR 68008, 68010.

The Commission states at 69 FRN 68008, 68011 that 50.69, while intended to ensure that the scope of STRs imposed on SSCs is risk-informed, is not intended to allow for the elimination of SSC functional requirements or to allow equipment that is required by the deterministic design basis to be removed from the facility (i.e., changes to the design of the facility must continue to meet the current requirements governing design change; most notably 10 CFR 50.59). Instead, the rule should enable licensees and the NRC staff to focus their resources on SSCs that make a significant contribution to plant safety by restructuring the regulations to allow an alternative risk-informed approach to special treatment. Conversely, for SSCs that do not significantly contribute to plant safety on an individual basis, this approach should allow an acceptable, though reduced, level of confidence (i.e., ''reasonable confidence'') that these SSCs will satisfy functional requirements. However, continued maintenance of the health and safety of the public will depend on effective implementation of 50.69 by the licensee or applicant applying the rule at its nuclear power plant. See 69 FR 68008, 68011.

In the FRN, the Commission responds to numerous public comments on the initially proposed version of 50.69. See 69 FR 68008, 68011-68016. A summary of the Commission responses to a sample of public comments related to the treatment of pumps, valves, and dynamic restraints is provided below:

1. In responding to public comments on the NRC review of treatment, the Commission determined that licensees could establish the treatment for RISC-3 SSCs without prior NRC review. As part of this determination, the Commission stated that it planned to conduct inspections of 50.69 implementation. These sample inspections are intended to gather information that will enable the NRC to assess whether modifications are needed to the ongoing baseline inspection program. The principal focus of the inspection will be on the safety significant aspects of 50.69 implementation such as categorization and treatment of RISC-1 and RISC-2 SSCs, but the inspection will also consider the implementation of RISC-3 treatment focusing on programmatic and common-cause issues, which could undermine the categorization process and its results. See 69 FR 68008, 6812.

2. In responding to public comments related to the use of voluntary consensus standards, the Commission clarified the 50.69 requirements to indicate that the treatment of RISC-3 SSCs must be consistent with the categorization process. The Commission indicated in the FRN that one way to achieve this consistency could be the application of consensus standards where the application of such standards meets the 50.69(d)(2) requirements for RISC-3 SSCs. See 69 FR 68008, 69013.

3. In responding to public comments related to design-basis conditions for RISC-3 SSCs, the Commission noted that under 50.69, RISC-3 SSCs will be exempt from STRs for qualification methods for environmental conditions and effects and seismic conditions. Nevertheless, the Commission stated that RISC-3 SSCs continue to be required to be capable of performing their safety-related functions under applicable environmental conditions and effects and seismic conditions, albeit at a lower level of confidence as compared to RISC-1 SSCs. In response to specific comments, the Commission stated that a licensee implementing 50.69 must consider operating life (aging) and combinations of operating life parameters (synergistic effects) in the design of RISC-3 electrical equipment. The Commission noted that this is particularly important if the equipment contains materials which are known to be susceptible to significant degradation due to thermal, radiation, and/or wear (cyclic) aging including any known synergistic effects that could impair the ability of the equipment to meet its design-basis function. However, the Commission agreed that the applicable rule language could be simplified and revised the rule to utilize a performance-based approach to ensuring with reasonable confidence the functional capabilities of RISC-3 SSCs. See 69 FR 68008, 68013-68014.

4. In responding to public comments on the use of seismic experience data, the Commission stated that in establishing 50.69, it did not intend to alter the existing seismic design requirements for RISC-3 SSCs in any plant's design basis. In meeting 50.69, the licensee or applicant must have adequate technical bases to conclude that RISC-3 SSCs will perform their safety-related functions under seismic design-basis conditions, which includes the number and magnitude of earthquake events specified for the SSC design. While the use of experience data is not prohibited by 50.69, it may be difficult for a licensee or applicant to show that experience data alone will satisfy the applicable design requirements of 10 CFR Part 100, "Seismic and Geologic Siting Criteria for Nuclear Power Plants," which 50.69 leaves intact. The Commission clarified that 50.69 will not change the seismic design basis

for Unresolved Safety Issue (USI) A-46 plants or impose additional seismic requirements for those plants. See 69 FR 68008, 68014.

In the FRN, the Commission provides a detailed discussion of the removal of RISC-3 and RISC-4 SSCs from the scope of specific STRs. See 69 FR 68008, 68020-68028.

In the FRN, the Commission specifies several regulatory requirements not removed by 50.69. For example, the Commission stated that it was not appropriate to include the technical specification requirements in 10 CFR 50.36 in the scope of 50.69 for several reasons, such as on-going risk-informed improvements to technical specifications, and relocation of less important SSCs to other documents. The Commission also concluded that the general design criteria (GDCs) in Appendix A, "General Design Criteria for Nuclear Power Plants," to 10 CFR Part 50 did not need to be revised because they apply design requirements and do not specify STRs. See 69 FR 68008, 68028-68030.

The guidance provided in the FRN by the Commission related to the treatment of pumps, valves, and dynamic restraints during the implementation of 50.69 is summarized in the following paragraphs:

A. Treatment of RISC-1 and 2 Pumps, Valves, and Dynamic Restraints

With respect to RISC-1 and RISC-2 treatment, the Commission states that for SSCs determined to be safety significant (i.e., RISC-1 and RISC-2 SSCs), the NRC regulations in 50.69 maintain the current regulatory requirements (i.e., 50.69 does not remove any requirements from these SSCs) for special treatment. These current requirements are adequate for addressing design-basis performance of these SSCs. Additionally, 50.69(d)(1) requires that sufficient treatment be applied to support the credit taken for these SSCs for beyond design-basis events. For example, in developing the probabilistic risk assessment (PRA) model, a licensee must determine the availability, capability, and reliability of RISC-1 and RISC-2 SSCs in performing specific functions under various plant conditions. These functions may be beyond the design basis for individual SSCs. Further, the conditions under which those functions are to be performed may exceed the design-basis conditions for the applicable SSCs. 50.69(d)(1) requires the treatment applied to RISC-1 and RISC-2 SSCs to be consistent with the performance credited in the categorization process. This includes credit with respect to prevention and mitigation of severe accidents. In some cases, licensees might need to enhance the treatment applied to RISC-1 or RISC–2 SSCs to support the credit taken in the categorization process, or conversely adjust the credit for performance of the SSC in the categorization process to reflect actual treatment practices and/or documented performance capability. In addition, 50.69(e) requires monitoring and adjustment of treatment processes or categorization decisions as needed based upon operational experience. See 69 FR 68008, 68019.

50.69(d)(1) requires that a licensee or applicant ensure that RISC-1 and RISC-2 SSCs perform their functions consistent with the categorization process assumptions by evaluating treatment being applied to these SSCs to ensure that it supports the key assumptions in the categorization process that relate to their assumed performance. This rule language means that the licensee or applicant must evaluate the treatment associated with those key assumptions in the PRA that relate to performance of particular SSCs. For example, if a relief valve was being credited with capability to relieve water (as opposed to its design condition of steam), such an evaluation would look at whether the component has been determined to be able to perform as assumed. See 69 FR 68008, 68040.

Because RISC-1 and RISC-2 SSCs are the safety significant SSCs and their performance as credited in the PRA is important to maintaining an acceptable level of plant risk, given that STRs are being removed from RISC-3 SSCs, it is a key and necessary part of 50.69 to ensure these SSCs can perform as credited in the PRA. However, the requirements in 50.69(d)(1) do not extend STRs to RISC-1 beyond design-basis functions and to RISC-2 SSCs. See 69 FR 68008, 68040.

The performance conditions for beyond design-basis capabilities of RISC-1 SSCs credited in the PRA are not subject to the requirements of 10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Reprocessing Plants." However, plant SSCs credited for beyond design-basis capabilities must have a valid technical basis for the credit (i.e., the failure rate/probability of the SSC performing the beyond design-basis function) given in the PRA. Further, the basis for this credit should already be established and documented in the PRA supporting documentation so this should not be an additional burden for licensees to capture and implement. If an existing technical basis does not exist or is insufficient to support the credit taken for beyond design-basis capability (e.g., the supporting test program does not test the SSC at the beyond design-basis conditions), the licensee or applicant is required by 50.69(d)(1) to develop a technical basis for the credit taken in the PRA potentially including a treatment program for the SSC that validates the capability credited. See 69 FR 68008, 68040.

For SSCs categorized as RISC-1 or RISC-2, all existing applicable requirements continue to apply (i.e., no STRs are removed by 50.69). 50.69 does not require licensees to evaluate the effectiveness of STRs for RISC-1 SSCs to ensure that they are capable of performing their design-basis functions. The STRs in other NRC regulations address the design-basis capability of RISC-1 SSCs. See 69 FR 68008, 68040.

The categorization process will result in a number of safety-related SSCs being determined to be of low safety significance (i.e., RISC-3) and subject to reduced treatment. This determination of low safety significance will implicitly take credit for the performance capability of other SSCs in the PRA, some, or all of which, may not be included in the scope of the licensee's categorization process (due to the allowance for licensees to selectively implement the rule and to phase that implementation over time). To maintain the validity of the categorization process, and more importantly to maintain any potential risk increase as small, it is necessary to maintain the ''credited'' SSCs per 50.69, and this means the application of 50.69(d)(1) and 50.69(e)(2) requirements for RISC-1 and RISC-2 SSCs. See 69 FR 68008, 68040.

B. Treatment of RISC-3 Pumps, Valves, and Dynamic Restraints

In the FRN, the Commission states that 50.69(d)(2) imposes requirements that are intended to maintain RISC-3 SSC design-basis capability. Although individually RISC-3 SSCs are not significant contributors to plant safety, they do perform functions necessary to respond to certain design-basis events of the facility. Thus, collectively, RISC-3 SSCs can be safety significant and as such, it is important to maintain their design-basis functional capability. Maintenance of RISC-3 design-basis functionality is important to ensure that defense-in-depth and safety margins are maintained. As a result, 50.69(d)(2) requires that licensees or applicants ensure with reasonable confidence that RISC-3 SSCs remain capable of performing their safety-related functions under design-basis conditions, including seismic conditions and environmental conditions and effects throughout their service life. To support this requirement, 50.69(d)(2) contains inspection, testing, and corrective action requirements, and in addition requires that the treatment of RISC-3 SSCs be consistent with the categorization process. The requirements are performance-based and give licensees the flexibility to implement treatment that they have determined is needed, commensurate with the low safety significance of the SSCs in order to provide reasonable confidence that their safety-related functional capability is maintained. In this context, ‘‘reasonable confidence’’ is a somewhat reduced level of confidence as compared with the relatively high level of confidence provided by the current STRs. See 69 FR 68008, 68019.

The alternative treatment requirements for RISC-3 SSCs represent a relaxation of those STRs that are removed for RISC-3 SSCs by the rule. For example, the alternative treatment requirements for RISC-3 SSCs in 50.69 are less detailed than provided in the STRs and allow significantly more flexibility by licensees in treating RISC-3 SSCs. The Commission is allowing greater flexibility and a lower level of assurance to be provided for RISC-3 SSCs in recognition of their low individual safety significance and this recognition includes a consideration for the potential change in reliability that might occur when treatment is reduced from what had previously been required by the STRs. In implementing the rule requirements, licensees will need to obtain data or information sufficient to make a technical judgement that RISC-3 SSCs will remain capable of performing their safety-related functions under design-basis conditions, and to enable the licensee to take actions to restore equipment performance consistent with corrective action requirements included in the rule. Effective implementation of the treatment requirements should result in reasonable confidence that RISC-3 SSCs will perform their safety-related function under normal and design-basis conditions. This level of confidence is both less than that associated with RISC-1 SSCs, which are subject to all STRs, and consistent with the low individual safety significance of RISC-3 SSCs. See 69 FR 68008, 68019-68020.

The Commission notes that changes that affect any non-treatment aspects of an SSC (e.g., changes to the SSC design-basis functional requirements) are still required to be evaluated in accordance with other regulatory requirements, such as 50.59. The Commission, in developing 50.69, was drawing a distinction between treatment (managed through 50.69) and design changes (managed through other processes, such as 50.59). The Commission notes that 50.69 is only risk-informing the scope of STRs. The process and requirements established in 50.69 do not extend to making changes to the design-basis functional requirements of SSCs. See 69 FR 68008, 68020.

The Commission states that through the application of 50.69, RISC-3 SSCs are removed from the scope of the specific STRs listed in 50.69(b)(1). Any regulatory requirements applicable to RISC-3 SSCs not removed by 50.69(b)(1) continue to apply. The STRs were originally imposed to provide a high level of assurance that safety-related SSCs would perform when called upon with high reliability. The Commission concluded that, in light of the low individual safety significance of RISC-3 SSCs, it is unnecessary to have the same high level of assurance that they would perform as designed. This is because some increased likelihood of their individual failure can be tolerated without significant impact to safety. Thus, the Commission decided to remove the RISC-3 SSCs from those detailed, specific requirements that provided the high level of assurance. However, the functional requirements for these SSCs remain. As an example, a RISC-3 component must still be designed to withstand any harsh environment it would experience under a design-basis event, but the NRC will not require that this capability be demonstrated by a qualification test. Further, the performance (and treatment) of these RISC-3 SSCs remain under regulatory control, but in a different way. Instead of the STRs, the Commission has set forth more general requirements by which a licensee is to maintain functionality. These requirements give the licensee more latitude in applying treatment to maintain the design-basis functional capability of the RISC-3 SSCs. The more general requirements that the Commission is specifying for the RISC-3 SSCs include inspection, testing, and corrective action, as a means of maintaining functionality. The Commission concludes that the requirements in 50.69 will maintain adequate protection of public health and safety if effectively implemented by licensees. See 69 FR 68008, 68020.

The Commission states that 50.69(b)(2)(iv) removes RISC-3 SSCs from the scope of certain provisions of 10 CFR 50.55a, relating to Codes and Standards. The provisions being removed are those that relate to ''treatment'' aspects, such as inspection and testing, but not those pertaining to design requirements established in 10 CFR 50.55a. 10 CFR 50.55a(f) incorporates by reference provisions of the American Society of Mechanical Engineers (ASME) *Operation and Maintenance of Nuclear Power Plants*, Division 1, OM Code: Section IST (OM Code), as endorsed by NRC, that contains IST requirements. These are specified to be STRs. Through this rule, RISC-3 SSCs are removed from the scope of these requirements and instead are subject to the requirements in 50.69(d)(2). The Commission has determined that for low safety significant SSCs, it is not necessary to impose the specific detailed provisions of the ASME OM Code, as endorsed by NRC, and these requirements can be replaced by the more ''high-level'' alternative treatment requirements, which allow greater flexibility to licensees in implementation. 10 CFR 50.55a(g) incorporates by reference provisions of the ASME *Boiler and Pressure Vessel Code* (BPV Code), Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components," as endorsed by NRC, that contain the inservice inspection, and repair and replacement requirements for ASME BPV Code Class 1, 2, and 3 SSCs. The Commission will not remove the repair and replacement provisions of the ASME BPV Code required by 10 CFR 50.55a(g) for ASME BPV Code Class 1 SSCs, even if they are categorized as RISC-3, because those SSCs constitute principal fission product barriers as part of the reactor coolant system or containment. For ASME BPV Code Class 2 and Class 3 SSCs that are shown to be of low safety significance and categorized as RISC-3, the additional assurance obtained from the specific provisions of the ASME BPV Code is not considered necessary. However, the Commission has not removed the requirements for fracture toughness specified for ASME BPV Code Class 2 and Class 3 SSCs because fracture toughness is a significant design parameter for the material used to construct the SSC. Fracture toughness is a property of the material that prevents premature failure of an SSC at abrupt geometry changes, or at small undetected flaws. Adequate fracture toughness of SSCs is necessary to prevent common cause failures due to design-basis events, such as earthquakes. See 69 FR 68008, 68025.

50.69(d)(2) requires that the licensee or applicant must ensure with reasonable confidence that RISC-3 SSCs remain capable of performing their safety-related functions under design-basis conditions, including seismic conditions and environmental conditions and effects throughout their service life. By ''reasonable confidence,'' the Commission means that the licensee or applicant is required to provide a ''reasonable confidence'' level with regard to maintaining the capability of RISC-3 safety-related functions. In this case, ''reasonable confidence'' is a level of confidence that is both less than that associated with RISC-1 SSCs, which are subject to all the STRs, and consistent with their individual low safety significance. The term ''ensure'' is intended to convey the Commission's determination that the licensee is under a legally-binding regulatory requirement to provide the requisite ''reasonable confidence.'' See 69 FR 68008, 68040-68041.

With respect to environmental capability, RISC-3 SSCs are removed from the scope of the requirements of 10 CFR 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants." The Commission concluded that for low safety significant SSCs, additional assurance, such as that provided by the detailed provisions in 10 CFR 50.49

for testing, documentation files and application of margins, are not necessary. Although 50.69(b)(1) removes for RISC-3 SSCs the environmental qualification requirements of 10 CFR 50.49, it does not eliminate the requirements in 10 CFR Part 50, Appendix A, that electric equipment important to safety be capable of performing their intended functions under the applicable environmental conditions. For example, GDC 4, "Environmental and Dynamic Effects Design Bases," in 10 CFR Part 50, Appendix A, requires that SSCs important to safety be designed to accommodate the effects of, and to be compatible with, the environmental conditions and effects associated with normal operation, maintenance, testing, and postulated accidents. To satisfy the provisions of GDC 4 of 10 CFR Part 50, Appendix A, the licensee or applicant must address environmental conditions such as temperature, pressure, humidity, chemical effects, radiation, and submergence; and environmental effects such as aging and synergisms. Therefore, the requirements in GDC 4 as they relate to RISC-3 SSCs, and the design-basis requirements for these SSCs, including the environmental conditions such as temperature and pressure, remain in effect. RISC-3 SSCs must continue to remain capable of performing their safety-related functions under design-basis environmental conditions. In accordance with 50.69(d)(2), the licensee or applicant must design electric equipment important to safety so they are capable of performing their intended functions under applicable environmental conditions and effects throughout their service life. If RISC-3 electrical equipment is relied on to perform its safety-related function beyond its design life, 50.69(d)(2) requires the licensee or applicant to have a basis for the continued capability of the equipment under adverse environmental conditions and effects. See 69 FR 68008, 68024-68025, and 68040-68041.

With respect to seismic capability, RISC-3 SSCs continue to be required to function under design-basis seismic conditions (such as design load combinations of normal and accident conditions with earthquake motions), but are not required to be qualified by testing or specific engineering methods in accordance with the requirements stated in 10 CFR Part 100, Appendix A. The rule does not remove the design requirements related to the capability of RISC-3 SSCs to remain functional considering Safe Shutdown Earthquake and Operating Basis Earthquake seismic loads, including applicable concurrent loads. The rule does not change the design input earthquake loads (magnitude of the loads and number of events) or the required load combinations used in the design of RISC-3 SSCs. The rule permits the licensee or applicant to select a technically defensible method to show that RISC-3 SSCs will remain functional when subject to design earthquake loads. See 69 FR 68008, 68041.

50.69(d)(2) requires that the treatment of RISC-3 SSCs be consistent with the categorization process. This rule language means that, when establishing the treatment for RISC-3 SSCs, the licensee or applicant must take into account the assumptions in the categorization process regarding the design-basis capability and reliability of RISC-3 SSCs to perform their safety-related functions throughout their service life. The evaluation by the licensee or applicant of the consistency of the treatment of RISC-3 SSCs with the categorization process may be qualitative so long as it provides reasonable confidence of the design-basis capability of RISC-3 SSCs, based on plant-specific and industry-wide operational experience and vendor information. In establishing treatment for RISC-3 SSCs, the licensee or applicant is responsible for addressing applicable vendor recommendations and operational experience such that the treatment established for RISC-3 SSCs provides reasonable confidence for design-basis capability. For example, operational experience might be described in NRC information notices or identified in responses to NRC bulletins, generic letters, or other licensee commitment documents. The treatment applied to RISC-3 SSCs must also support the assumptions used in justifying the removal of requirements applicable to those SSCs. For example, where a licensee or applicant intends as part of implementing 50.69 to eliminate leakage testing required in 10 CFR Part 50,

Appendix J, “Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors,” for containment isolation valves, the treatment applied to those valves must support the assumption that they are capable of closing under design-basis conditions. See 69 FR 68008, 68041.

As described in NUREG/CR-6752, ‘‘A Comparative Analysis of STRs for Systems, Structures, and Components (SSCs) of Nuclear Power Plants with Commercial Requirements of Non-Nuclear Power Plants,’’ significant variation exists in the application of industrial practices at nuclear power plants. Hence, a simple reference to these practices does not provide a basis to satisfy the rule’s requirements. To satisfy the requirement that the treatment of RISC-3 SSCs be consistent with the categorization process, the licensee or applicant must establish treatment that provides reasonable confidence SSCs perform their safety-related functions under design-basis conditions and is consistent with the assumptions in the categorization process (e.g., reliability levels). The licensee or applicant must either establish treatment that provides this level of reliability or use consensus standards that provide a proven level of reliability based on experience. In using consensus standards, the licensee or applicant must note that combining or omitting provisions of standards might result in ineffective implementation of 50.69 by causing RISC-3 SSCs to be incapable of performing their design-basis safety functions. See 69 FRN 68008, 68041-68042.

In addition to the guidance in the FRN, it should be noted that NUREG/CR-6752 includes significant discussion regarding the definition of reasonable confidence. For example, NUREG/CR-6752 provides guidance for possible criteria to consider when determining reasonable confidence. The basic message of the NUREG guidance is that reasonable confidence is usually demonstrated by other elements beyond commercial requirements such as a combination of:

- Commercial Requirements
- Engineering Specifications
- Plant Processes
- Plant Procedures
- QA Programs

Of course, a NUREG provides guidance rather than requirements so a licensee might develop different criteria regarding its definition of reasonable confidence. The NUREG guidance might be considered by NRC inspectors when determining if a licensee’s alternate treatment for a RISC-3 SSC provides reasonable confidence of functionality.

Under 50.69, most STRs will be removed from RISC-3 SSCs, which will typically comprise a large percentage of safety-related SSCs in a nuclear power plant. These STRs will be replaced with the high-level treatment requirements in 50.69(d)(2) that will allow significant reduction in the treatment applied to RISC-3 SSCs. This reduction in treatment can introduce common-cause concerns and weaken defenses against them. Therefore, 50.69(d)(2) requires that inspection, testing and corrective action be provided for RISC-3 SSCs. The inspection and testing requirement in 50.69(d)(2)(i) is to provide sufficient performance data for RISC-3 SSCs to determine if the reduction in treatment has adversely affected their design-basis capability and to provide reasonable confidence that the SSC can perform its safety function throughout their service life. The corrective action requirement in 50.69(d)(2)(ii) is to address SSC failures and provide reasonable confidence in avoiding future problems. These requirements are necessary to provide reasonable confidence that RISC-3 safety-related functional capability is maintained and thereby avoid adverse impacts on the reliability and availability of multiple RISC-3 SSCs, which could reduce plant safety beyond the categorization process assumptions or results and invalidate the risk sensitivity results. See 69 FR 68008, 68042.

A licensee or applicant may not simply assume that a sensitivity study that increases the failure probability for all RISC-3 SSCs simultaneously, with no additional basis to support it, would necessarily bound the potential change in risk that could result due to implementation of 50.69. There is a potential that risk due to implementation of 50.69 could increase as a result of the reduction in treatment due to common-cause interactions or degradation, and this impact might not be uniform across the population of RISC-3 SSCs. For example, if a licensee were to simply eliminate maintenance, testing, or lubrication of pumps or valves, it could significantly impact performance of those specific components and the impact might exceed the cumulative impact of individually reducing the reliability of all RISC-3 SSCs by a few percent or less. In satisfying 50.69, the licensee or applicant must consider potential common-cause interactions and degradation mechanisms in establishing treatment for RISC-3 SSCs so there is a reasonable basis to support the assumptions made for the risk sensitivity study. See 69 FR 68008, 68042.

50.69(d)(2)(i) requires the licensee to conduct periodic inspection and testing activities to determine whether RISC-3 SSCs will remain capable of performing their safety-related functions under design-basis conditions. The prescriptive STRs in 10 CFR 50.55a and 50.65 for inspection, testing, and surveillance have been removed for RISC-3 SSCs. In lieu of those prescriptive requirements, the rule requires the licensee or applicant to implement inspection and testing of RISC-3 SSCs sufficient to provide reasonable confidence that RISC-3 SSCs remain capable of performing their safety-related functions under design-basis conditions throughout their service life. The licensee or applicant may apply industrial practices for the treatment of RISC-3 SSCs if those practices maintain the capability of the RISC-3 SSCs to perform their design-basis safety functions. See 69 FR 68008, 69042.

50.69(d)(2)(i) means that the licensee or applicant must implement periodic testing or inspection sufficient to provide reasonable confidence that RISC-3 pumps and valves will be capable of performing their safety-related functions under design-basis conditions. To determine that the pump or valve will remain capable of performing its safety-related function, the licensee or applicant will need to obtain sufficient operational information or performance data to provide with reasonable confidence that the RISC-3 pumps and valves will be capable of performing their safety-related functions if called upon to function under operational or design-basis conditions over the interval between periodic testing or inspections. In addition, the operational information and performance data must be sufficient to satisfy the requirements of 50.69(d)(2)(i) for use in identifying the need for corrective action under 50.69(d)(2)(ii) and in providing information for feedback to the categorization and treatment processes under 50.69(e)(3). See 69 FR 68008, 68042.

In some cases, a licensee or applicant implementing 50.69 might apply more rigorous test methods than previously applied to satisfy the ASME OM Code IST provisions because 50.69 does not specify restrictive time limits on test intervals that were provided in the ASME OM Code. As a result, 50.69 allows significant flexibility by the licensee or applicant in verifying the design-basis capability of their safety-related SSCs categorized as RISC-3. However, the licensee or applicant needs to consider the lessons learned over the last 20 years regarding SSC performance in establishing the treatment for RISC-3 SSCs. Operating experience and research do not support an assumption that exercising a valve or pump will provide reasonable confidence of design-basis capability in that such exercising will not detect service-induced aging or degradation that could prevent the component from performing its design-basis functions in the future, and therefore is insufficient by itself to satisfy 50.69(d)(2)(i). The licensee or applicant may develop the type and frequency of tests or inspections for RISC-3 pumps and valves provided they are sufficient to conclude that the pump or valve will perform its safety-related function throughout the service life. The provisions for risk-informed inspection and testing in applicable ASME Code Cases (as incorporated in 10 CFR 50.55a) would constitute one effective approach for satisfying the 50.69 requirements. See 69 FR 68008, 68042.

50.69(d)(2)(ii) requires that conditions that would prevent a RISC-3 SSC from performing its safety-related functions under design-basis conditions must be corrected in a timely manner. In the case of significant conditions adverse to quality, the rule requires that measures be taken to provide reasonable confidence that the cause of the condition is determined and corrective action taken to preclude repetition. Significant conditions adverse to quality include common-cause concerns for multiple RISC-3 SSCs or concerns related to the validity of the categorization process or its results. For example, if measuring and test equipment is found to be in error or defective, the licensee or applicant will be responsible for determining the functionality of safety-related SSCs checked using that equipment to prevent the occurrence of common-cause problems that might invalidate the categorization process assumptions and results. Effective implementation of the corrective action process would include timely response to information from plant SSCs, overall plant operations, and industry generic activities that might reveal performance concerns for RISC-3 SSCs on both an individual and common-cause basis. The corrective action process alone is insufficient to monitor the effects of reduced treatment on RISC–3 SSCs, and therefore the Commission has incorporated feedback requirements into 50.69. See 69 FR 68008, 68043.

C. Treatment of RISC-4 Pumps, Valves, and Dynamic Restraints

With respect to RISC-4 treatment, the Commission states that 50.69 does not impose any new treatment requirements on RISC-4 SSCs. Instead, RISC-4 SSCs are simply removed from the scope of any applicable STRs identified in 50.69(b)(1). Requirements applicable to RISC-4 SSCs not removed by 50.69(b)(1) continue to apply. Any changes (beyond changes to STRs) must be made per existing design change control requirements including 10 CFR 50.59, as applicable. See 69 FR 68008, 68020.

D. Feedback, Documentation, and Reporting Guidance

With respect to the feedback, documentation, and reporting requirements, the Commission states that the validity of the categorization process relies on ensuring that the performance and condition of SSCs continue to be maintained consistent with applicable assumptions. Changes in the level of treatment applied to an SSC might result in changes in the reliability of the SSCs credited in the categorization process. Additionally, plant changes, changes to operational practices, and plant and industry operational experience may impact categorization process results. Consequently, the rule contains requirements for updating the categorization and treatment processes when conditions warrant to assure that continued SSC performance is consistent with the categorization process and results. Specifically, the rule requires licensees to review the changes to the plant, operational practices, applicable plant and industry operational experience, and, as appropriate, update the PRA and SSC categorization. The review must be performed in a timely manner but no longer than once every two refueling outages. In addition, licensees are required to obtain sufficient information on SSC performance to verify that the categorization process and its results remain valid. See 69 FR 68008, 68030.

For RISC-1 SSCs, much of the performance information may be obtained from present programs for inspection, testing, surveillance, and maintenance. However, for RISC-2 SSCs and for RISC-1 SSCs credited for beyond design-basis accidents, licensees need to ensure that sufficient information is obtained. For RISC-3 SSCs, there is a relaxation of the requirements for obtaining information when compared to the applicable STRs. However, sufficient information still needs to be obtained. The rule requires considering performance data, determining if adverse changes in performance have occurred, and making the necessary adjustments so that desired performance is achieved so that the evaluations conducted to meet 50.69(c)(1)(iv) remain valid. See 69 FR 68008, 68030.

The feedback and adjustment process is crucial to ensuring that the SSC performance is maintained consistent with the categorization process and its results. Taking timely corrective action is an essential element for maintaining the validity of the categorization and treatment processes used to implement 50.69. For safety significant SSCs, all current requirements continue to apply and, as a consequence, Appendix B corrective action requirements are applied to the design-basis aspects of RISC-1 SSCs to ensure that conditions adverse to quality are corrected. For both RISC-1 and RISC-2 SSCs, requirements are included in 50.69(e)(2) for monitoring and for taking action when SSC performance degrades. When a licensee or applicant determines that a RISC-3 SSC does not meet its established acceptance criteria for performance of design-basis functions, the rule requires that a licensee perform timely corrective action under 50.69(d)(2)(ii). Further, as part of the feedback process, the review of operational data may reveal inappropriate credit for reliability or performance, and a licensee would need to re-visit the findings made in the categorization process or modify the treatment for the RISC-3 SSCs under 50.69(e)(3). These provisions would then restore the facility to the conditions that were considered in the categorization process and would also restore the capability of the SSCs to perform their functions. See 69 FR 68008, 68030.

50.69(f) requires the licensee or applicant to document the basis for its categorization of SSCs before removing STRs. 50.69(f) also requires the licensee or applicant to update the final safety analysis report to reflect which systems have been categorized. See 69 FR 68008, 68030.

50.69(g) requires reporting of events or conditions that prevented, or would have prevented, a RISC-1 or RISC-2 SSC from performing a safety significant function. Because the categorization process has determined that RISC-2 SSCs are of safety significance, the NRC is interested in reports about circumstances where a safety significant function was, or would have been, prevented because of events or conditions. This reporting will enable NRC to be aware of situations impacting those functions found to be significant under 50.69, so that NRC can take any actions deemed appropriate. See 69 FR 68008, 68030.

A summary of the reporting requirements in 50.69(g) is as follows:

- Existing reporting requirements are retained for RISC-1and RISC-2 SSCs.

- Existing reporting requirements for RISC-1 include 10 CFR Part 21, 10 CFR 50.55(e), 10 CFR 50.72 and 50.73. In particular, 10 CFR 50.55(e) refers to the definitions 10 CFR 21.3 for applicability to construction permits and combined licenses.

- Existing reporting requirements for RISC-2 include 10 CFR 50.72 and 50.73.

- Section III.4.1.1 of the 50.69 FRN concludes that RISC-2 components are not in the existing scope of Part 21 and 10 CFR 50.55(e) reporting requirements.

- RISC-3 and RISC-4 SSCs are specifically excluded from reporting requirements for Part 21[50.69(b)(i)], 10 CFR 50.55(e) [50.69(b)(iv)], 10 CFR 50.72 [50.69(b)(vii)] and 10 CFR 50.73 [50.69(b)(viii)].

In the FRN, the Commission states that 50.69(g) provides a new reporting requirement applicable to events or conditions that prevented, or would have prevented, a RISC–1 or RISC–2 SSC from performing a safety significant function. Most events involving these SSCs will meet existing 10 CFR 50.72 and 50.73 reporting criteria. However, it is possible for events and conditions to arise that impact whether RISC-1 or RISC-2 SSCs would perform beyond design basis functions consistent with the performance capability credited in the categorization process. This reporting requirement is intended to capture these situations. The reporting requirement is contained in 50.69, rather than as a revision of 10 CFR 50.73, so that its applicability only to those facilities that have implemented 50.69 is clear. The existing reporting requirements in 10 CFR 50.72 and 50.73 are removed for RISC-3 (and RISC-4) SSCs under 50.69(b)(vii) and (viii). See 69 FR 68008, 68044.

As a summary of the above FRN guidance, most events involving RISC-1 and RISC-2 SSCs will meet existing 10 CFR 50.72 and 50.73 reporting requirements. No reporting requirements for RISC-1 or RISC-2 SSCs are removed. The FRN clarifies that the purpose of 50.69(g) is to add the requirement for reporting under 10 CFR 50.73 for RISC-1 and RISC-2 SSCs that have beyond-design-basis functional capability credited in the 50.69 categorization process. Thus, any previous 10 CFR 50.72 or 50.73 reporting requirements for an SSC that is categorized as RISC-1 or RISC-2 under 50.69 remain applicable. For example, 10 CFR 50.72(b)(3)(iv)(B)(1) states:

> (B) The systems to which the requirements of paragraph (b)(3)(iv)(A) of this section apply are:
>
> (1) Reactor protection system (RPS) including: Reactor scram and reactor trip.

An example of a RISC-2 SSC that may fill this particular 10 CFR 50.72 reporting requirement is a failure of the Turbine Cooling Water system that trips the turbine generator, which then causes a reactor scram.

Properly implemented, these requirements ensure that the validity of the categorization process and results are maintained throughout the operational life of the plant. See 69 FR 68008, 68030.

IV. Categorization Guidance

In Regulatory Guide (RG) 1.201 (Revision 1), "Guidelines for Categorizing Structures, Systems, and Components in Nuclear Power Plants according to their Safety Significance," the NRC staff accepts Nuclear Energy Institute (NEI) 00-04, "10 CFR 50.69 Categorization Guideline," for the SSC categorization process for implementation of 50.69. RG 1.201 states that STRs are removed for RISC-3 SSCs and replaced with high-level requirements intended to provide sufficient regulatory treatment, such that SSCs are still expected to perform their safety-related functions under design-basis conditions, albeit at a reduced level of assurance compared to current STRs. RG 1.201 states that 50.69 does not allow these RISC-3 SSCs to lose their functional capability or be removed from the facility.

V. Specific Knowledge Transfer Activities

The NRC staff has implemented knowledge transfer activities to provide information for NRC inspectors and engineers regarding 50.69. For example, the staff has conducted training sessions in each of the NRC Region offices and its headquarters facility. In addition, the staff includes a summary of the Commission guidance for the testing and inspection requirements in 50.69 for pumps, valves, and dynamic restraints (snubbers) that are classified as RISC-3 components in Revision 3 to NUREG-1482, "Guidelines for Inservice Testing at Nuclear Power Plants," issued July 2020.

VI. NRC Inspections of 10 CFR 50.69 Programs

In the FRN, the Commission states that the NRC does not plan to perform a pre-implementation review of the revised treatment requirements under 50.69(d). The Commission indicated that the NRC will review and update, as appropriate, the then-current inspection procedures under the NRC Reactor Oversight Process to incorporate inspection guidance for monitoring the implementation of 50.69 at nuclear power plants. The NRC intends to conduct sample inspections of plants implementing 50.69 in a manner that is sensitive to conditions that could significantly increase risk. These sample inspections are intended to gather information that will enable the NRC to assess whether modifications are needed to the ongoing baseline inspection program. The sample inspections will focus on the implementation of the categorization process approved as part of the NRC review of the 50.69 license amendment request. The sample inspections will also evaluate the treatment established under 50.69 with primary attention directed to programmatic and common-cause issues; including those associated with known degradation mechanisms. The inspections might help provide operating experience information on RISC-3 SSCs that can also be provided to other licensees.

Following issuance of the FRN, the NRC prepared Inspection Procedure (IP) 37060, "10 CFR 50.69 Risk-Informed Categorization and Treatment of Structures, Systems, and Components Inspection," dated July 2020, to provide guidance for the inspection of licensee programs for implementation of 50.69. The NRC staff has initiated inspections of the implementation of 50.69 at specific nuclear power plants that have received 50.69 license amendments.

VII. Conclusion

Many licensees have submitted license amendment requests (LARs) to implement 10 CFR 50.69 programs at their nuclear power plants. The NRC has approved those LARs for several nuclear power plants and is reviewing additional requests. The NRC staff will continue to conduct inspections of the implementation of 50.69 at a sample of nuclear power plants that have received 50.69 license amendments. The NRC staff will continue to provide updated guidance on the implementation of 50.69 based on lessons learned from the ongoing activities.

VIII. References

1. 10 CFR 50.69, "Risk-Informed Categorization and Treatment of Structures, Systems, and Components for Nuclear Power Plants" (Government Publishing Office website).

2. *Federal Register* notice (69 FRN 68008), "Risk-Informed Categorization and Treatment of Structures, Systems and Components for Nuclear Power Reactors; Final Rule," dated November 22, 2004 (U.S. Government Office of Federal Register website).

3. 10 CFR 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants" (Government Publishing Office website).

4. NUREG-1482, Revision 3, "Guidelines for Inservice Testing at Nuclear Power Plants," issued July 2020 (NRC's Agencywide Documents Access and Management System (ADAMS) Accession No. ML20202A473).

5. NUREG/CR-6752, ''A Comparative Analysis of STRs for Systems, Structures, and Components (SSCs) of Nuclear Power Plants with Commercial Requirements of Non-Nuclear Power Plants,'' dated January 2002 (ADAMS Accession No. ML0203300051).

6. NRC Regulatory Guide 1.201, "Guidelines for Categorizing Structures, Systems, and Components in Nuclear Power Plants according to their Safety Significance," Revision 1 (NRC public website).

7. Nuclear Energy Institute 00-04, "10 CFR 50.69 Categorization Guideline," dated July 2005 (ADAMS Accession No. ML052910035).

8. NRC Inspection Procedure 37060, "10 CFR 50.69 Risk-Informed Categorization and Treatment of Structures, Systems, and Components Inspection," dated July 2020 (ADAMS Accession No. ML20192A322).

9. NRC Inspection Report 05000424 and 425/2016008, "Vogtle Electric Generating Plant – NRC Evaluation of Risk-Informed Categorization and Treatment of Systems, Structures, and Components," dated August 10, 2016 (ADAMS Accession No. ML16223A738).

10. NRC Inspection Report 05000352 and 05000353/2020010, "Limerick Generating Station, Units 1 and 2 – Title 10 of the Code of Federal Regulations 50.69 Risk-Informed Categorization and Treatment of Structures, Systems, and Components," dated March 11, 2020 (ADAMS Accession No. ML20073H282).

ASME OM Code Subsection ISTE – A Discussion of the Upcoming Subsection

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Member ASME OM Committee

Abstract

Subsection ISTE, "Risk-Informed Inservice Testing of Components in Water-Cooled Reactor Nuclear Power Plants," in the American Society of Mechanical Engineers (ASME) *Operation and Maintenance of Nuclear Power Plants*, Division 1, OM Code: Section IST (OM Code) provides mandatory requirements for owners of nuclear power plants who voluntarily elect to implement a risk-informed inservice testing (IST) Program. Subsection ISTE was originally prepared by combining the component categorization requirements and methodology from ASME OM Code Case OMN-3, "Requirements for Safety Significance Categorization of Components Using Risk Insights for Inservice Testing of LWR Power Plants," with component specific testing requirements developed, or under development, by the component-specific subgroups. Many of these requirements were based on the existing risk-informed Code Cases. The original publication of Subsection ISTE was not endorsed unconditionally by the NRC. The ASME OM Subcommittee on Risk-Informed Activities revised the subsection to address NRC concerns and the revised Subsection ISTE was published in the 2020 Edition of the ASME OM Code. The NRC staff has proposed to endorse this version of Subsection ISTE in its regulations with no conditions. This paper presents an overview of the latest version of Subsection ISTE including requirements for categorizing plant pumps and valves as either High Safety Significant Components or Low Safety Significant Components in accordance with Subsection ISTE, summarizes component treatment and reporting requirements, and presents examples.

1.0 Introduction

ASME OM Code, Subsection ISTE, provides mandatory requirements for owners of nuclear power plants who voluntarily elect to implement a risk-informed inservice testing (IST) Program for pumps and valves. Subsection ISTE was originally prepared by combining the component categorization requirements and methodology from ASME OM Code Case OMN-3 with the test requirements of the Risk-Informed Component Code Cases, Appendix II for check valves, Appendix III for electric motor-operated valves (MOVs), and Appendix IV for pneumatically operated valves (AOVs).

Subsection ISTE does not address hydraulically operated valves (HOVs) or dynamic restraints (snubbers). ASME OM Code Case OMN-10, "Requirements for Safety Significance Categorization of Snubbers Using Risk Insights and Testing Strategies for Inservice Testing of LWR Power Plants," provides different requirements for the safety significance categorization of snubbers than Subsection ISTE. The incorporation of HOVs and snubbers may be addressed by the incorporation of alternate risk ranking provisions and component IST treatment requirements in future revisions of Subsection ISTE.

2.0 Technical Requirements

2.1 General Requirements

2.1.1 Implementation

Subsection ISTE contains a number of general requirements, the first of which is a requirement on implementation. The requirement on implementation requires the owner to implement Subsection ISTE on the entire population of the same type of component in the plant. Component types are defined as:

a) Centrifugal pumps, including vertical line shaft pumps,
b) Positive displacement pumps,
c) Motor-operated valves (MOVs),
d) Pneumatically Operated Valves (AOVs)
e) Check Valves (CVs)

While this requirement requires owners to implement Subsection ISTE on the entire population the same type of component in the plant, it also allows owners to implement Subsection ISTE by individual component types at a time and even only a single component type.

It must be emphasized that Subsection ISTE requires the subsection be implemented on the entire population of the same type of component in the plant, not just the components in the existing IST Program. Owners must evaluate every component of the selected type in the plant for safety significance categorization. This may include components outside the IST Program as well as components not modeled in the probabilistic risk assessment (PRA). Components outside the IST Program and components not modeled in the PRA that are classified as High Safety Significant Components (HSSCs) must be included in the Risk-Informed IST Program. However, components outside the IST Program and components not modeled in the PRA that are classified as Low Safety Significant Components (LSSCs) are not required to be included in the Risk-Informed IST Program.

2.1.2 Probabilistic Risk Assessment

Subsection ISTE requires the owner to demonstrate the technical adequacy of the plant-specific PRA to perform component risk ranking and for estimating the aggregate risk impact. PRA technical adequacy shall be assessed using ASME/ANS RA-S-2008 standard with the RA-Sa-2009 Addenda or acceptance criteria that are acceptable to the regulatory agency having jurisdiction over the plant site.

Subsection ISTE contains requirements for PRA configuration control. The PRA must reflect plant modifications in a timely manner and be updated at least once every two refueling outages or five years, whichever is shorter.

2.1.3 Integrated Decision Making

Subsection ISTE requires that an IST-specific Plant Expert Panel be established and that this expert panel make component-specific as well as integrated risk-informed decisions. The Plant Expert Panel is required to combine risk-informed component information with deterministic engineering and performance information for each component in order to categorize each component as HSSC or LSSC.

The Plant Expert Panel is also required to consider the integrated effects of multiple risk-informed applications, including risk-informed applications outside of ASME OM Code scope. The integrated effect of all risk-informed applications at the plant must be considered including the risk-informed IST program.

2.1.4 Evaluation of Aggregate Risk

The Plant Expert Panel is also required to evaluate the aggregate risk impact of implementation of the risk-informed IST Program using both quantitative evaluations and qualitative assessments. Addition information on aggregate risk evaluation is presented under specific requirements.

2.1.5 Feedback and Corrective Action

Subsection ISTE requires that feedback and corrective action processes be established for the risk-informed IST Program. Addition information on feedback and corrective actions is presented under specific requirements.

3.0 Specific Component Categorization Requirements

The specific component categorization requirements of Subsection ISTE apply to all components evaluated. These requirements are the same for all component types addressed by Subsection ISTE.

The categorization process is a two-phase process. The first phase is risk categorization using the PRA. The second phase is safety categorization where deterministic criteria are blended with the risk criteria to establish the final categorization of the components as HSSCs or LSSC.

3.1 Component Risk Categorization

Component risk categorization is performed with information taken from the plant-specific PRA.

3.1.1 Appropriate Failure Modes

Components are usually modeled in the PRA as “Basic Events” that represent different failure modes or other reasons the component may not be available to perform its function. Typical failure modes for PRA components are:

Valves
- Fail to Open
- Fail to Close
- Transfer Open
- Transfer Closed
- Plugged (Disk Stuck)
- Maintenance Unavailability
- Common Cause Failure

Pumps
- Fail to Start
- Fail to Run
- Fail to Provide Sufficient Flow
- Maintenance Unavailability

- Common Cause Failure

The failure modes appropriate for a risk-informed IST program are those failure modes that can be identified by IST activities. These include for valve, Fail to Open, Fail to Close, and Plugged. For pumps, the appropriate failure modes could be Fail to Start and Fail to Provide Sufficient Flow.

Maintenance unavailability failure modes are not applicable to the risk-informed IST program for valves or pumps because these are usually planned activities and inservice test results will not identify this unavailability. Transfer Open and Transfer Closed failure modes for valves typically represent spurious operation of the valve. These failure modes are also not applicable to the risk-informed IST program.

There are often multiple Common Cause Failure basic events for components. These will represent groups of redundant or diverse components serving a common or similar function. Common Cause Failure basic events are important, but you must verify that the failure mode being modeled is applicable to the risk-informed IST program.

3.1.2 Importance Measures

Many importance measures can be derived from a PRA. Subsection ISTE does not disallow the use of any importance measures. However, Subsection ISTE does require the use of the Fussell-Vesely (FV) and Risk Achievement Worth (RAW) importance measures. Subsection ISTE also requires the importance measures used be evaluated for Core Damage Frequency (CDF) and Large Early Release Frequency (LERF), if available.

The FV importance measure represents the fractional contribution to the total of the selected figure of merit for all accident sequences containing that basic event. The RAW importance measure represents the increase in a selected figure of merit when an SSC is assumed to be unable to perform its function due to testing, maintenance, or failure. It is the ratio or interval of the figure of merit, evaluated with the SSC's basic event probability set to one, to the base case figure of merit.

3.1.3 Screening Criteria

Subsection ISTE does establish screening criteria for the initial risk categorization. For those components modeled in the PRA, a threshold value of FV > 0.005 or a RAW > 2 based on either CDF or LERF should be initially considered as HSSC. If the FV and RAW for a component in the PRA are less that these screening criteria the components should initially be considered as LSSC.

3.1.4 Sensitivity Studies

Subsection ISTE requires sensitivity studies be performed. The objective of these sensitivity studies is to investigate whether any components classified as LSSC through the screening process should be considered as HSSCs.

The following sensitivity studies are required:

1. Data and Uncertainties - Failure probabilities of selected components within the PRA shall be assessed to determine if the results are sensitive to changes in the failure data.

2. Human Recovery Actions - The PRA shall be re-quantified, and the FV and RAW importance measures recalculated, after human actions modeled in the PRA, to recover from specific component failures, are adjusted in the models. This sensitivity shall ensure that the categorization has not been unduly affected by the modeling of recovery actions.
3. Test and Maintenance Unavailabilities – The PRA shall be re-quantified with test and maintenance unavailabilities appropriately adjusted, and the importance measures recalculated.
4. LSSC Failure Rates – Failure rates shall be simultaneously increased by a factor representing the upper bound (95%) of the failure rate and the PRA models re-quantified.
5. Truncation Limits – If the PRA has not been quantified with a truncation limit 10^{-4} below the baseline PRA CDF, the PRA model shall be re-quantified with the truncation limit lowered to this value. The importance measures shall then be re-calculated.
6. Common Cause – Sensitivity analyses shall be used to determine the impact of increased or decreased common-cause failure rates.

The results of these sensitivity studies and any others that are performed are required to be documented including the magnitude of the changes to the CDF or LERF. The results and insights of these sensitivity studies are provided to the Plant Expert Panel for their consideration in the final categorization of the components.

3.1.5 Qualitative Assessments

Subsection ISTE requires qualitative assessments be performed. Similar to the sensitivity studies above, the objective of these qualitative assessments is to investigate whether any components classified as LSSC through the screening process should be considered as HSSCs.

Qualitative assessments are required to be performed for plant-specific design bases conditions and events not modeled in a PRA.

The following qualitative assessments are required to be considered:

1. Impact of initiating events – The impact of LSSC failure or degradation as it might result in an initiator or component contribution to initiating events represented by point estimates.
2. Shutdown conditions – The potential consequences of shutdown (outage) conditions on LSSC importance.
3. External initiating events – LSSC response to external initiating events (e.g., seismic, fire, high winds/tornadoes, flooding, etc.)
4. Large Early Release Frequency – LSSC impact on LERF if not quantified in the screening assessment.
5. LSSC impact on the plant to:
    a. prevent or mitigate accident conditions;
    b. reach and/or maintain safe shutdown conditions;
    c. preserve the reactor primary coolant pressure boundary integrity; and
    d. maintain containment integrity.
6. LSSC considerations of:
    a. Safety function being satisfied by the component's operation;

b. level of redundancy existing at the plant to fulfill the component's function;
c. ability to recover from a failure of the component;
d. performance history of the component;
e. plant Technical Specifications requirements applicable to the component;
f. Emergency Operating Procedure instructions that use the component(s); and
g. Design and current licensing basis information relevant to risk-informed IST component function.

7. The cumulative impacts of combinations of LSSC unavailability which could impact an entire system (e.g., multi-train impacts) or critical safety function (e.g., multi-system impacts).

The results of these qualitative assessments are required to be documented, and made available to the Plant Expert Panel for its consideration in the final categorization of the components.

3.1.6 <u>Components not Modeled in the PRA</u>

If IST components not modeled in the PRA are subsequently determined by the Plant Expert Panel to have an impact upon the ability of the facility to respond to analyzed events, consideration should be given to updating the PRA model to incorporate the effects of the component(s), then using the updated model to provide a quantified basis for categorization (either HSSC or LSSC).

3.2 Component Safety Categorization

The component safety categorization process is one in which the Plant Expert Panel categorizes components relative to their safety significance as HSSCs or LSSC using both deterministic and probabilistic insights. The probabilistic insights come from the component risk categorization above.

3.2.1 <u>Plant Expert Panel Utilization</u>

Subsection ISTE specifies requirements and guidance for the Plant Expert Panel to blend deterministic and probabilistic information to classify IST components into HSSC or LSSC categories.

3.2.2 <u>Plant Expert Panel Requirements</u>

Subsection ISTE establishes basic requirements for the Plant Expert Panel for developing and implementing a risk-informed IST Program.

3.2.2.1 Procedure

An approved plant procedure shall describe the process, including:

1. Designated members and alternates;
2. Designated chairperson and alternate;
3. Quorum;
4. Attendance records;
5. Agendas;
6. Motions for approval;
7. Process for decision making;

8. Documentation and resolution of differing opinions;
9. Minutes;
10. Implementation of feedback/ corrective actions;
11. Feedback to the PRA; and
12. Required training.

3.2.2.2 Training

The Plant Expert Panel shall be trained and indoctrinated in the specific requirements to be used for Subsection ISTE. Training and indoctrination are required to include the application of risk analysis methods and techniques. At a minimum, the risk methods and techniques should include:

1. PRA fundamentals (e.g., PRA technical approach, PRA assumptions and limitations, failure probability, truncation limits, uncertainty);
2. Use of risk importance measures;
3. Assessment of failure modes;
4. Reliability versus availability;
5. Risk thresholds; and
6. Expert judgment elicitation.

3.2.2.3 Expertise

Subsection ISTE requires that the expertise level for Plant Expert Panel members be documented and maintained.

3.2.2.4 Plant Expert Panel Membership

Subsection ISTE requires at least five experts be designated as members of the Plant Expert Panel. Members may be experts in more than one field; however, excessive reliance on any one member's judgment shall be avoided.

The chairperson is required to be familiar with Subsection ISTE and is responsible to facilitate Plant Expert Panel activities, to ensure that the requirements of Subsection ISTE are satisfied.

Subsection ISTE requires expertise in the following functional areas be represented on the Plant Expert Panel:

- Operation
- Safety Analysis Engineering
- Probabilistic Risk Assessment
- ASME Inservice Testing

Additional members of the Plant Expert Panel may be selected who have the following plant expertise:

- Systems Performance
- Maintenance
- Licensing
- Component Performance
- Quality Assurance
- Design Engineering

3.2.3 Plant Expert Panel Decisions

Plant Expert Panel decision criteria for categorizing components as HSSC and LSSC are required to be documented. Subsection ISTE requires that decisions of the Plant Expert Panel be arrived at by consensus. Differing opinions are required to be documented and resolved, if possible. If a resolution cannot be achieved concerning the safety significance classification of a component, then the component is required to be classified HSSC.

If components have a high initial ranking from the PRA (i.e., FV >0.005 or RAW >2) but are ultimately ranked as LSSCs, the Plant Expert Panel decisions shall provide justification and shall be documented.

3.3 Test Strategy Formulation

Test strategies must be developed to allow for the evaluation of aggregate risk. Test strategies differ from specific test treatments. Test strategies includes consideration of test frequency, testing effectiveness, and out of service duration.

3.4 Evaluation of Aggregate Risk

The evaluation of aggregate risk includes a combination of quantitative and qualitative evaluations. It is required that appropriate decision criteria for aggregate risk effects be established and documented for both quantitative and qualitative assessments. These decision criteria must be based on thresholds for aggregate risk limits using standard figures-of-merit (e.g., CDF, LERF). The evaluation of aggregate risk must be performed before implementation of the risk-informed IST Program.

3.4.1 Quantitative Assessment of Aggregate Risk

Subsection ISTE requires that proposed IST program changes be assessed to determine compliance with approved decision criteria and to quantitatively determine if any adjustments or compensatory measures are warranted. Types of quantitative attributes that should be considered in the quantitative evaluation include changes in:

1. testing frequency,
2. out of service duration,

3. failure rates,
4. failure modes,
5. common cause failure susceptibility,
6. compensatory measures, and
7. testing scheme (staggered or simultaneous testing).

Compensatory measures include both those specifically incorporated into plant programs and those developed for specific situations. Management directed compensatory measures should also be included in the quantitative assessment, as appropriate. Documented failure rates shall be used in the quantification process for IST component.

Once all appropriate inputs have been incorporated, the PRA is to be rerun to assess the overall risk impact.

3.4.2 Qualitative Evaluation of Aggregate Risk

Subsection ISTE requires that aggregate risk effects be qualitatively evaluated (i.e., risk decreases as well as risk increases) for IST program changes (e.g., testing effectiveness). Pertinent performance indicators, industry programs, or other scrutable methods for establishing aggregate risk effects are required to be identified and monitored. Feedback processes and corrective action programs are to be considered in the evaluation of aggregate risk.

3.5 Defense in Depth and Safety Margin

As with other risk-informed application and programs, defense in depth and safety margin must be maintained. Subsection ISTE contains requirements and guidelines for maintaining defense in depth and safety margin.

3.6 Inservice Testing Program

Subsection ISTE has specific requirements related to the IST Program which apply to all components in the IST Program.

3.6.1 Maximum Test Interval

The maximum test interval for a component, or group of components, cannot exceed either of the following:

1. The maximum interval allowed by the results of the aggregate risk evaluation, or
2. The maximum interval supported by the performance history of the component(s).

3.6.2 Implementation Schedule and Assessment of Aggregate Risk

Subsection ISTE requires that an implementation schedule be developed for implementing the revised testing strategies. Once the schedule is developed it must be assessed against the assumptions in the aggregate risk evaluation.

3.6.3 Transition Plan

A transition plan is required to be developed for each component type to ensure adequate information is collected to support justification of stepwise test interval extension up to and including the maximum allowable interval. Staggered test intervals are allowed to be used for implementing a stepwise test interval extension.

4.0 Specific Component Testing Requirements

4.1 Pumps

4.1.1 HSSC Pumps

Pumps categorized as HSSCs are required to meet all requirements of ASME OM Code, Subsections ISTA and ISTB or ISTF.

4.1.2 LSSC Pumps

In general, LSSC pumps are required to be tested less frequently and further from the design flow conditions than HSSC pumps.

4.1.2.1 Pre-2000 Plants

LSSC pumps are required to meet all the requirements of ASME OM Code, Subsections ISTA and ISTB, except that the testing intervals are essentially doubled. LSSC pumps are also required to receive an initial Group A test conducted at the comprehensive pump flow rate soon as practical and no later than the first refueling outage following implementation of the risk-informed IST Program. Thereafter, LSSC pumps are required to be Group A tested at the comprehensive pump flow rate at least once every 5 years or 3 refueling outages, whichever is longer.

4.1.2.2 Post-2000 Plants

Pumps categorized as LSSCs are required to meet all requirements of ASME OM Code, Subsections ISTA and ISTF, except that the testing requirements of paragraph ISTF-3400 may be substituted by the following testing requirements:

1. LSSC pumps are required to receive an initial test conducted at the inservice test flow rate as soon as practical and no later than the first refueling outage following implementation of the risk-informed IST Program.
2. Thereafter, the LSSC pumps are required to be tested every 6 months in accordance with Subsection ISTF and within ± 20% of pump design flow rate at least once every 5 years or 3 refueling outages, whichever is longer.

4.2 Check Valves

4.2.1 HSSC Check Valves

Subsection ISTE requires that HSSC check valves be placed in a Condition Monitoring Program and tested in accordance with ASME OM Code, Mandatory Appendix II.

4.2.2 LSSC Check Valves

LSSC check valves are required to be tested in accordance with ASME OM Code, Subsection ISTC, or placed in a Condition Monitoring Program and tested in accordance with ASME OM Code, Mandatory Appendix II.

4.3 Motor Operated Valves

4.3.1 HSSC MOVs

HSSC MOVs are required to be tested in accordance with ASME OM Code, Mandatory Appendix III, using established test frequencies and a mix of static and dynamic testing.

4.3.2 LSSC MOVs

Subsection ISTE allows grouping of LSSC MOVs with relaxed grouping requirements from ASME OM Code, Mandatory Appendix III. The grouping must be technically justified. LSSC MOVs must also be associated with another group of MOVs wherever possible; and when a member of that group is tested, the test results must be analyzed in accordance with Mandatory Appendix III and the results applied to all LSSC MOVs associated with that group.

LSSC MOVs that are not able to be associated with another established group shall be tested in accordance with Mandatory Appendix III using an initial test frequency of 3 refueling outages or 5 years, whichever is longer until sufficient data exists to determine a more appropriate test frequency.

LSSC MOVs are also required to be tested at least every 10 years in accordance with Mandatory Appendix III.

4.4 Pneumatically Operated Valves

Pneumatically operated valves are required to meet all the requirements of ASME OM Code, Subsections ISTA and ISTC, except that they may be tested in accordance with ASME OM Code, Mandatory Appendix IV.

5.0 Monitoring, Analysis, and Evaluation

5.1 Performance Monitoring

Subsection ISTE specifies different performance monitoring requirements for HSSC and LSSCs.

5.1.1 HSSC Attribute Trending

For HSSCs, a set of performance attributes to be tested is required to be established and compared to acceptance criteria and a trending program be implemented for those attributes. This is individual component-specific trending, but can be applied to groups of similar components.

5.1.2 LSSC Performance Trending

For LSSCs, the risk-informed inservice testing is required to be supplemented by performance monitoring. The performance of the LSSCs shall be trended to ensure that the LSSC component failure rates do not increase to unacceptable levels. This performance trending need not be component-specific, and may be performed on the entire population of LSSC components of the same type.

5.2 Feedback and Corrective Action

Subsection ISTE requires a feedback process be developed incorporating elements of both conditional and periodic feedback such that component performance information is directed to both the IST and PRA programs. Conditional feedback is required in a timely fashion following component failure. Periodic feedback is considered for maintenance of the PRA. The feedback frequency should not exceed two refueling cycles.

In addition to the requirements in the IST Code of Record with respect to Corrective Actions, Subsection ISTE requires a Corrective Action Program be established that identifies and tracks to resolution all failures of similar types of components within the IST Program incorporating risk insights, including evaluation of generic implications.

5.3 Records and Reports

Subsection ISTE includes requirements for records and reports in addition to those required by the IST Code of Record. These additional requirements apply to the Plant Expert Panel and component records.

5.3.1 Plant Expert Panel Records

Subsection ISTE requires the following records be maintained related to the Plant Expert Panel:

1. membership and attendance,
2. member expertise representation and training,
3. member experience (years of experience in each of the expertise categories),
4. meeting agendas,
5. meeting minutes, and
6. plant procedure.

5.3.2 Component Records

Subsection ISTE requires the following component records be maintained:

1. risk significance based on PRA importance measures,
2. additional PRA quantitative information,
3. deterministic information,
4. Plant Expert Panel categorization decisions of HSSC or LSSC, and
5. basis for the HSSC and LSSC decisions.

New Reactors

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NRC Inspection Activities for Functional Design, Qualification, and Preservice and Inservice Testing Programs at New Reactors*

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Abstract

U.S. Nuclear Regulatory Commission (NRC) Inspection Procedure (IP) 73758, “Part 52, Functional Design and Qualification, and Preservice and Inservice Testing Programs for Pumps, Valves and Dynamic Restraints,” provides inspection requirements and guidance for the functional design, qualification, and preservice testing (PST) and inservice testing (IST) programs for pumps, valves, and dynamic restraints at nuclear power plants under construction in accordance with Part 52, “Early Site Permits; Standard Design Certifications; and Combined Licenses for Nuclear Power Plants,” of Title 10, “Energy,” of the Code of Federal Regulations (10 CFR Part 52). The inspection objectives of IP 73758 are (1) to evaluate the establishment, implementation, and results of the functional design and qualification of pumps, valves, and dynamic restraints (snubbers) during construction of nuclear power plants with a combined license (COL) in accordance with 10 CFR Part 52; and (2) to evaluate the establishment, implementation, and results of PST and IST programs for pumps, valves, and dynamic restraints during construction of nuclear power plants with a COL license in accordance with 10 CFR Part 52. For example, the COL documentation for current new reactors specify the design and qualification of pumps, valves, and dynamic restraints through implementation of American Society of Mechanical Engineers (ASME) Standard QME-1-2007, “Qualification of Active Mechanical Equipment Used in Nuclear Power Plants,” as accepted in NRC Regulatory Guide (RG) 1.100 (Revision 3), “Seismic Qualification of Electrical and Active Mechanical Equipment and Functional Qualification of Active Mechanical Equipment for Nuclear Power Plants.” The NRC has updated RG 1.100 in Revision 4 to accept ASME Standard QME-1-2017. In addition, ASME has updated the Operation and Maintenance of Nuclear Power Plants (OM Code) to improve the IST provisions for pumps, valves, and dynamic restraints that are incorporated by reference in Section 55a, “Codes and standards,” of Part 50, “Domestic Licensing of Production and Utilization Facilities,” in Title 10, “Energy,” of the *Code of Federal Regulations* (10 CFR 50.55a) with applicable conditions. This paper discusses the inspection requirements and guidance in IP 73758 and the ongoing NRC inspection activities to implement IP 73758 for Vogtle Electric Generating Plant (VEGP) Units 3 and 4.

I. Introduction

In preparation for construction of nuclear power plants licensed in accordance with Part 52, "Early Site Permits; Standard Design Certifications; and Combined Licenses for Nuclear Power Plants," of Title 10, "Energy," of the *Code of Federal Regulations* (10 CFR Part 52), the NRC issued Inspection Procedure (IP) 73758, "Part 52, Functional Design and Qualification, and Preservice and Inservice Testing Programs for Pumps, Valves and Dynamic Restraints," to provide inspection requirements and guidance for the functional design, qualification, and preservice testing (PST) and inservice testing (IST) programs for pumps, valves, and dynamic restraints (snubbers) at Part 52 nuclear power plants. The NRC staff has initiated inspection activities to implement IP 73758 for Vogtle Electric Generating Plant (VEGP) Units 3 and 4.

II. NRC Regulations

The NRC regulations in 10 CFR Part 52 provide a process for the licensing of new nuclear power plants in the United States as an alternative to the process described in 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities."

The NRC regulations in Appendix A, "General Design Criteria for Nuclear Power Plants," to 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities," specify requirements for structures, systems, and components (SSCs) important to safety that provide reasonable assurance that the facility can be operated without undue risk to the health and safety of the public. General Design Criterion (GDC) 1 in Appendix A to 10 CFR Part 50 states that SSCs important to safety shall be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed. GDC 1 also states that where generally recognized codes and standards are used, they shall be identified and evaluated to determine their applicability, adequacy, and sufficiency, and shall be supplemented or modified as necessary to assure a quality product in keeping with the required safety function. GDC 1 also requires that a quality assurance (QA) program be established and implemented in order to provide adequate assurance that these SSCs will satisfactorily perform their safety functions. Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," to 10 CFR Part 50 specifies criteria for the QA program to provide adequate confidence that SSCs will perform their safety-related functions satisfactorily in service.

At the time of this paper, the NRC regulations in 10 CFR 50.55a incorporate by reference specific editions and addenda of the American Society of Mechanical Engineers (ASME) *Operation and Maintenance of Nuclear Power Plants*, Division 1, OM Code: Section IST (OM Code) up to the 2017 Edition for implementation of PST and IST programs for pumps, valves, and dynamic restraints used in nuclear power plants. The ASME OM Code (1995 Edition through 2006 Addenda) specifies the performance of stroke-time testing of motor-operated valves (MOVs) on a quarterly frequency as part of the IST program. Beginning with the 2009 Edition, the ASME OM Code includes Mandatory Appendix III, "Preservice and Inservice Testing of Active Electric Motor Operated Valve Assemblies in Light-Water Reactor Power Plants," which replaces quarterly stroke time testing of MOVs with periodic exercising at least every refueling outage, and periodic diagnostic testing based on capability margin up to a maximum interval of 10 years. Beginning with the 2011 Addenda, the ASME OM Code includes Subsection ISTF, "Inservice Testing of Pumps in Light-Water Reactor Nuclear Power Plants – Post-2000 Plants," with PST and IST provisions for pumps in nuclear power plants that were (or will be) issued their construction permit, or combined license (COL) for construction and operation, on or following January 1, 2000 (referred to herein as new reactors). Beginning with the 2012 Edition, the ASME OM Code includes PST and IST surveillance provisions for pyrotechnic-actuated (squib) valves in new reactors in Subsection ISTC, “Inservice Testing of Valves in Light-Water Reactor Nuclear Power Plants.” The 2017 Edition of the ASME OM Code includes a new Appendix IV, “Preservice and Inservice Testing of Active Pneumatically Operated Valve Assemblies in Nuclear Reactor Power Plants,” to improve the IST provisions for air-operated valves (AOVs) by supplementing the quarterly stroke-time testing provisions with PST diagnostic performance assessment tests for all AOVS within the scope of the ASME OM Code and periodic diagnostic performance assessment tests for AOVs with high safety significance.

The regulatory conditions for new reactors in 10 CFR 50.55a include provisions for periodic verification of the design-basis capability of power-operated valves (POVs) to perform their safety functions; bi-directional testing of check valves; flow-induced vibration monitoring; and regulatory treatment of non-safety systems (RTNSS) in new reactors with passive emergency cooling systems.

The NRC regulations in 10 CFR 50.55a(f)(4)(i) require that inservice tests to verify operational readiness of pumps and valves, whose function is required for safety, be conducted during the initial 120-month interval must comply with the requirements in the latest edition and addenda of the ASME OM Code incorporated by reference in 10 CFR 50.55a(b) on the date 18 months before the date scheduled for initial fuel loading under a COL issued per 10 CFR Part 52 or the optional ASME OM Code Cases listed in NRC Regulatory Guide (RG) 1.192, “Operation and Maintenance Code Case Acceptability, ASME OM Code,” subject to the limitations and modifications listed in 10 CFR 50.55a.

III. Inspection Procedure IP 73758

In April 2013, the NRC initially issued IP 73758 in preparation for the construction of nuclear power plants licensed under 10 CFR Part 52. In September 2018, the NRC issued an update to IP 73758 to reflect lessons learned from nuclear power plant operating experience (including Anchor/Darling double-disc gate valve stem-disc connection integrity issues), vendor component qualification, NRC inspection results, new ASME OM Code editions, and NRC rulemaking since initial issuance of IP 73758. In February 2020, the NRC issued a further update to IP 73758 to revise the recommended sample size for valves and dynamic restraints to provide greater flexibility to inspectors and to reduce inspection resource estimates.

IP 73758 specifies inspection objectives for the functional design and qualification, and PST and IST programs for pumps, valves, and dynamic restraints at nuclear power plants licensed under 10 CFR Part 52. The inspection objectives specified in IP 73758 are (1) to evaluate the establishment, implementation, and results of the functional design and qualification of pumps, valves, and dynamic restraints; and (2) to evaluate the establishment, implementation, and results of PST and IST programs for pumps, valves, and dynamic restraints, during construction of nuclear power plants with a COL license in accordance with 10 CFR Part 52.

The performance of IP 73758 involves an initial program inspection, an implementation inspection of the functional design and qualification program, an implementation inspection of the PST/IST program, and a close-out inspection for the functional design, qualification, and PST/IST programs for pumps, valves, and dynamic restraints in preparation for plant startup. These inspection activities will be conducted at different times during the construction process. It is intended that the close-out inspection for this IP be completed 6 months before planned fuel loading in order to support an NRC staff finding on the completion of all operational programs consistent with the schedule for the finding that the inspections, tests, analyses, and acceptance criteria (ITAAC) have been met in accordance with 10 CFR 52.103(g).

IP 73758 has been prepared with four appendices as follows:

Appendix A, “Review of Functional Design, Qualification, and PST/IST Programs for Pumps, Valves, and Dynamic Restraints,”

Appendix B, “Implementation of Functional Design and Qualification Program for Pumps, Valves, and Dynamic Restraints,”

Appendix C, “Implementation of PST/IST Program for Pumps, Valves, and Dynamic Restraints,” and

Appendix D, “Close-Out Inspection for Functional Design, Qualification, and PST/IST Programs for Pumps, Valves, and Dynamic Restraints in Preparation for Plant Startup.”

Appendix A to IP 73758 specifies inspection requirements and guidance for evaluating the functional design and qualification program for pumps, valves, and dynamic restraints. Appendix A to IP 73758 also provides inspection requirements and guidance for evaluating the PST/IST program for pumps, valves, and dynamic restraints.

Appendix B to IP 73758 specifies inspection requirements and guidance for evaluating the implementation of the functional design and qualification program for pumps, valves, and dynamic restraints.

Appendix C to IP 73758 specifies inspection requirements and guidance for evaluating the implementation of the PST/IST program for pumps, valves, and dynamic restraints.

Appendix D to IP 73758 specifies inspection requirements and guidance for evaluating the completion of the functional design and qualification process for pumps, valves, and dynamic restraints in preparation for plant startup. Appendix D to IP 73758 also provides inspection requirements and guidance for evaluating the full implementation of the PST/IST program for pumps, valves, and dynamic restraints in preparation for plant startup.

Attachments to IP 73758 provide more specific inspection requirements and guidance for functional design, qualification, and PST/IST programs for MOVs, AOVs, and pyrotechnic-actuated valves (squib valves) to be used in nuclear power plants licensed under 10 CFR Part 52. Additional attachments for other components or associated activities may be prepared in the future.

IV. IP 73758 Training

The NRC staff has conducted training sessions for NRC inspectors and headquarters staff on the content of IP 73758 as part of MOV knowledge transfer activities. The training includes lessons learned from NRC inspections conducted of MOV programs developed in response to Generic Letter (GL) 89-10, “Safety-Related Motor-Operated Valve Testing and Surveillance,” and GL 96-05, “Periodic Verification of Design-Basis Capability of Safety-Related Motor-Operated Valves.” The NRC staff plans to provide updated training to incorporate lessons learned from the implementation of IP 73758 at VEGP Units 3 and 4.

V. IP 73758 Implementation

In November 2019, the NRC staff initiated the implementation of IP 73758 for VEGP Units 3 and 4 at the Westinghouse offices in Cranberry Township, PA. The staff conducted this initial inspection for functional design and qualification of pumps, valves, and dynamic restraints for VEGP Units 3 and 4 at the Westinghouse offices to allow greater efficiency in the review of readily available documentation. During the licensing of VEGP Units 3 and 4, the licensee specified the application of ASME Standard QME-1-2007, "Qualification of Active Mechanical Equipment Used in Nuclear Power Plants," for the design and qualification of pumps, valves, and dynamic restraints. The NRC accepted the use of ASME Standard QME-1-2007 in RG 1.100 (Revision 3), "Seismic Qualification of Electrical and Active Mechanical Equipment and Functional Qualification of Active Mechanical Equipment for Nuclear Power Plants." The NRC inspection report for the initial implementation of IP 73758 for VEGP Units 3 and 4 is dated February 11, 2020 (ADAMS Accession No. ML20042E292).

In 2021, the NRC staff is continuing the implementation of IP 73758 for the functional design and qualification, and PST and IST programs for pumps, valves, and dynamic restraints for VEGP Units 3 and 4. The staff is conducting the IP 73758 inspections primarily by remote means as a result of the current COVID virus concerns. The staff is reviewing licensee and contractor documents associated with the functional design, qualification, and inservice testing of pumps, valves, and dynamic restraints for VEGP Units 3 and 4 made available by the licensee in an electronic reading room. The staff conducts virtual meetings with the licensee and its supporting contractors to discuss the applicable documents and to address staff questions regarding the information in those documents. At the time of the preparation of this paper, the staff considers the inspection approach to have been successful in implementing the inspection requirements and recommendations specified in IP 73758 for the functional design, qualification, and IST programs for pumps, valves, and dynamic restraints at VEGP Units 3 and 4. The staff is incorporating the IP 73758 inspection results into the quarterly integrated inspection reports being prepared for VEGP Units 3 and 4.

The NRC staff described the background and history of the development of inspection guidance for IST programs in a paper titled "Expectations for Inservice Testing Programs at New Nuclear Power Plants" presented at the ASME/NRC Thirteenth Symposium on Valves, Pumps, and Inservice Testing for Operating and New Reactors conducted on July 17-18, 2017, in Silver Spring, Maryland, USA. NRC staff expectations for the IP 73758 inspection activities are provided in that paper. See NUREG/CP-0152 (Volume 10), "Proceedings of the 13th NRC/ASME Symposium on Valves, Pumps, and Inservice Testing."

VI. Conclusion

The NRC staff plans to complete the implementation of IP 73758 for the functional design, qualification, and PST and IST programs for pumps, valves, and dynamic restraints at VEGP Units 3 and 4. Following this inspection activity, the staff plans to update IP 73758 to incorporate lessons learned from those inspection activities. The staff will implement IP 73758 for the functional design, qualification, and PST and IST programs for pumps, valves, and dynamic restraints at future nuclear power plants licensed in accordance with 10 CFR Part 52.

VII. References

1. U.S. *Code of Federal Regulations*, Title 10, "Energy," Part 50, "Domestic Licensing of Production and Utilization Facilities," and Part 52, "Licenses, Certifications, and Approvals for Nuclear Power Plant." (Available on NRC or U.S. Government Publishing Office (GPO) website.)

2. ASME *Boiler & Pressure Vessel Code*. (Available through ASME website.)

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4. ASME Standard QME-1-2007, "Qualification of Active Mechanical Equipment Used in Nuclear Power Plants." (Available through ASME website.)

5. ASME Standard QME-1-2017, "Qualification of Active Mechanical Equipment Used in Nuclear Facilities." (Available through ASME website.)

6. *Federal Register*, 85 Fed. Reg. 26540, dated May 4, 2020 (Available through the National Archives and Records Administration website).

7. NRC GL 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance." (Available on NRC website.)

8. NRC GL 96-05, "Periodic Verification of Design-Basis Capability of Safety-Related Motor-Operated Valves." (Available on NRC website.)

9. NRC Inspection Procedure IP 73758 (February 2020), "Part 52, Functional Design and Qualification, and Preservice and Inservice Testing Programs for Pumps, Valves, and Dynamic Restraints." (Available on NRC website.)

10. NRC RG 1.100 (Revision 4), "Seismic Qualification of Electrical and Active Mechanical Equipment and Functional Qualification of Active Mechanical Equipment for Nuclear Power Plants." (Available on NRC website.)

11. NUREG/CP-0152 (Volume 10), "Proceedings of the 13th NRC/ASME Symposium on Valves, Pumps, and Inservice Testing," August 2019, NRC Agencywide Document Access and Management System (ADAMS) Accession No. ML19219A165.

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Inservice Testing for Gen-4 and Beyond - Inservice Testing for Any Plant

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The following paper is the opinion of the author. Nothing in this paper is to be construed as the opinion or direction of the ASME OM Standards Committee.

Abstract

The American Society of Mechanical Engineers (ASME) *Operation and Maintenance of Nuclear Power Plants*, Division 1, OM Code: Section IST (OM Code) applied to nuclear power plants that are currently in operation is a mature code. While the OM Code is "fully developed," additional requirements have been driven by adverse industry events. Such events, like valve stem/disc separation, have caused additional requirements to be added. The OM Code is a component code. So, the methods to ensure operational readiness has nothing to do with the plant that the component is in. Rather, it can be based solely of the required function of the component in its most basic sense. This presentation presents a case for a new code that can be used in any industry as well as for Small Modular Reactor Plants.

1. Current OM Code for IST Background

The American Society of Mechanical Engineers (ASME) *Operation and Maintenance of Nuclear Power Plants*, Division 1, OM Code: Section IST (OM Code) applied to nuclear power plants that are currently in operation is a mature code. While the OM Code is "fully developed," additional requirements have been driven by adverse industry events. Such events, like valve stem/disc separation, have caused additional requirements to be added. The OM Code is written to Light Water Reactor Plants. There is currently no consideration of those Small Modular Reactors (SMR) that are not water-cooled reactors in the current OM Code, and none has been developed.

2. A Component Code

Several aspects of OM Code require verification of component design basis. This is beyond the original charter for the OM Code. These design-basis verifications are currently required for motor-operated valves, air-operated valves, and pumps that have a specific flow rate that is in the credited Safety Analysis.

The original concept of OM was to ensure operational readiness and be able to detect degradation. OM is not to ensure operability; it is to ensure operational readiness. Its purpose is to detect degradation, and to trend it such that the component can be reworked before it fails. In the case of the valve stem/disc separation issue, it is a case of looking for something that has already failed. That was not the original intent of OM. The intent of OM was to find a degrading condition before the component failed. The Code changes do nothing to fix that underlying issue.

3. Accommodations due to Plant Design

The current OM Code is directed squarely at Light Water Reactor Plants. One reason, in the author's opinion, is that this was the type of plant that the U.S. Navy was standardizing to, and this is what the then-current industry infrastructure was working on. However, there were system design issues that caused several, for lack of a better word, accommodations. In many respects, these plants were designed before the need for Inservice Testing (IST) was understood, or the requirements written down in a Code or Standard.

The best example that comes to mind is the fact that most Pressurized Water Reactor (PWR) plants had pumping systems that did not have full flow test loops, while Boiling Water Reactor (BWR) plants did. Another example is setting valve exercise testing interval based on when the system can be made available for testing. This meant that some valves can only be tested during a plant shutdown irrespective of importance to safety. Indeed, some low safety significance valves are tested quarterly, simply because they can (no plant outage required).

4. IST Scope of Components

The OM Committee has had to deal many times with questions regarding what components are in the scope of IST. One requirement is the supply of emergency power for a pump to be in scope as well as exclusions based on nominal size. There are new plants that are being designed that do not require emergency power, and have valves that are smaller than those in similar service in the current plants. Would they need to be in an IST program? The issue becomes complicated when you consider the significant number of new SMR designs. There also needs to be a consideration that new types of plants will be developed. To get to the same level of expertise with all of these different plants and to be able to write a scope statement that encompasses all of the components that are important to safety is virtually impossible. However, since OM is a component code, it should be straight forward to write test considerations on a component basis. The question of importance to safety need not rest with the code writers. Instead, it should be with the new plant designers and their regulator.

5. Other Things to Consider

The current OM definition of a “New Plant” being Post-2000 is no longer accurate. Currently, AP-1000 plants as well as NuScale have prepared IST programs with a recent edition of the OM Code.

There is a very broad range of SMR designs. The delta between the design of many of the SMRs and current plants is significant, especially for those that are not Light Water Reactors. If these plants are designed with no consideration of periodic testing, as was done with the plants that were built before IST requirements were known, we will have the same problems that we have had with the current plants. Further, while the designs of the Light Water Reactors were well understood by both the writers of the Code, and the regulators, that is not the case for the SMRs.

6. Summary of the Current OM Code

The current OM Code has strayed away from being a component only code and now includes design-basis verification in several instances. The issue here is that the current OM Code had to include several accommodations because many of the current plants were in operation before there was an OM Code. This meant that several components did not consider that they would need to be periodically tested. Additionally, some components have design bases functions that were never specified at the time when the component was originally specified (i.e., gate valves that have a function to isolate postulated pipe rupture flow rate, with a few exceptions, did not even specify a flow rate to size the actuator). Components in new plants should be qualified by the ASME QME-1 Standard before they are installed in the plant. That would provide the information that would need to be periodically verified by the IST program. Nevertheless, the techniques required for periodic component testing are not a function of what kind of a plant or system that it is in.

ASME *Boiler and Pressure Vessel Code* (BPV Code, Section III, is a design code. So, a design code may need to consider the design of the plant in which it is used. A testing code for components doesn't need to. Further, the only part of the OM Code that has any consideration of ASME BPV Code Class is ASME OM Code, Appendix I, for safety valves. There was a reason for this originally. Is that still a valid reason for SMRs?

A manufacturer who is part of the QME Committee was approached by an Oil Company that asked if the QME-1 Standard could be used to qualify valves on an oil rig. Is the same possible for the OM Code?

7. A NEW OM CODE, CONCLUSIONS

The current OM Code needs to remain for the current operating plants. At this point, the OM Code needs to consider how it can be more efficient. Cooperation and a dialog with the Regulator are very helpful and necessary. Changes to the OM Code based on industry issues that are, frankly, cases of poor system design, incorrect equipment sizing, or use of a type of component that is inappropriate for its required function should not require a change to the OM Code. Nothing in a code to verify operational readiness can correct these issues.

The new code should start with a clean slate. It needs to consider what the function of a component is and determine what needs to be done to periodically verify that it is not degrading in service to a point where it cannot provide the function. Verification that the component type is appropriate for the service and that it provides the functions and parameters for which were specified is in the ASME QME-1 Standard. The new OM code needs to be structured so that it is directly usable for any type of Small Modular Reactor Plant. By extension, such a code could be used by any industry. For a component code, ASME needs to avoid scoping based on any particular system and be based on parameters only. That is flowrate, flowing medium, temperature, material compatibility, ambient environment, etc. Function should be set up based on the broad functions for pumps and valves and not the system function in any particular nuclear steam supply system.

As a plus, since the proposed new code is strictly component based, and the designer will determine what is in scope during the licensing/permitting process, such a code could readily be used by non-nuclear industries.

Considerations for In-Service Testing Requirements for Advanced Non-Light Water Reactors*

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*This paper was prepared by staff of the U.S. Nuclear Regulatory Commission (NRC). It may present information that does not currently represent an agreed upon NRC staff position. NRC has neither approved nor disapproved the technical content.

Abstract

With the development of non-light water advanced reactors, the conditions to which components and materials will be exposed will vary greatly in comparison with that of light water reactors. This paper will review some of the different environments that active mechanical equipment and their materials in advanced reactors will be exposed to and the different operating conditions and degradation mechanisms compared to water-cooled nuclear power plants due to the different normal, abnormal, and accident environmental and service conditions. The qualification of active components and the materials to be used in advanced reactors needs to be demonstrated for the applicable postulated service and environmental conditions (including impurities) to provide assurance that the active mechanical equipment can perform its intended safety function. This paper discusses the considerations for the design, qualification, and inservice testing of active components and materials that may be used in various advanced reactor designs and how the conditions differ from that of light water reactors. Also included is some of the operating experience gained from international non-light water reactor experience that has been accumulated for several reactor types that may be of use when considering development of the standards for qualification and inservice testing of mechanical components and materials.

1. Introduction

There is a lot of interest in advanced reactors to improve overall safety from a loss of coolant or radiological release. Advanced reactors are also being considered to reduce dependence on diesel fuel to run generators in remote locations. The new reactors have significant design differences than current operating reactors, and there are several new reactor designers. For instance, Terrestrial Power has two designs, the Traveling Wave Reactor and the Integral Molten Salt Reactor (IMSR). General Atomics is working on a Helium-Cooled Fast Reactor design. Westinghouse is working on the eVinci design. Oklo Inc. is developing the Aurora compact fast reactor design. Kairos Power LLC is designing the Fluoride Salt-Cooled, high temperature reactor. TerraPower is working on the molten chloride fast reactor (MCFR). These new reactor designs will require different considerations for inservice testing (IST) and qualification of components and materials for active mechanical equipment.

2. Materials and Methods

Generally, information was taken from the world wide web regarding reactor design information and publicly available information in the NRC Agencywide Document Access and Management System (ADAMS).

2.1 Design Differences

Advanced Non-Light Water Reactors (non-LWRs) have significant design differences from operating reactors. Key differences are the operating pressure, the coolant used, the nuclear-spectrum fast vs. moderated, and operating temperatures, to name a few. Regarding the coolants, some are sodium, lead, or salt cooled, which operate at practically atmospheric pressure. Some use helium and are pressurized, but not to the pressures of pressurized water reactors. Some use heat pipes to transfer energy from the reactor core to heat exchangers that transfer energy to secondary systems. Fuel types are different. Liquid fuels, in which the fuel is dissolved in the coolant are being contemplated rather than the uranium dioxide ceramic fuel pellets used in operating reactors. TRISO (TRi-structural ISOtropic particle) fuel is used in some reactor designs. The TRISO fuel offers significant resistance to fission product migration through the barrier layers in the TRISO fuel. Metal fuels are used in yet other reactors, which also provide protection from fission product migration and release.

These different design features bring new safety features to these reactor designs. The use of coolants that have higher vaporization temperatures allows the reactors to be operated at basically atmospheric pressure. Also, the high temperature capability of the fuel, allows for passive heat transfer techniques to keep the fuel below the melting point. But what does this mean for the materials used in these new designs? The temperatures at which they will operate will be much higher than those of the light water reactors. The vision currently is to eventually increase reactor operating temperatures to approximately 950 degrees °C (~1750 degrees Fahrenheit (ºF)). The different coolant types also mean different corrosion potential for the reactor materials. Sodium, salt, lead, and helium all bring various corrosion concerns for the wetted coolant surfaces. Contaminants in the coolant may significantly change the corrosivity of the coolant.

a. Creep and Creep-Fatigue

Creep is a time-dependent strain at elevated temperature and constant stress. In other words, strain will increase without the application of any additional stress. The phenomenon is material dependent. Figure 1 represents a typical strain-time curve for a material operating in the creep regime.

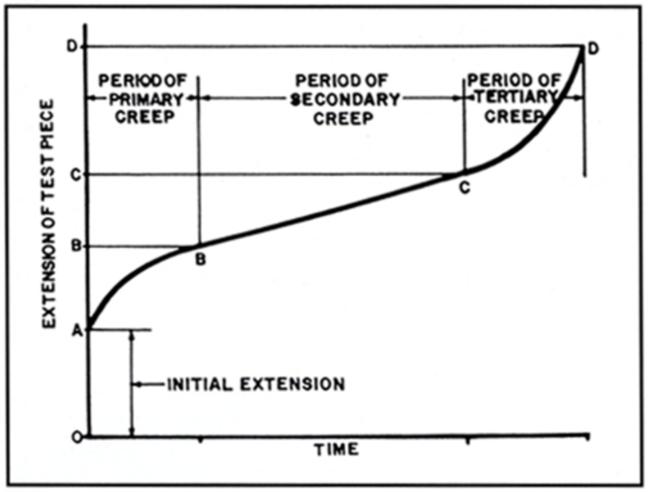

Figure 1: Typical strain vs. time creep curve. David N. French, Sc. D. National Board Classic Series, published in the National Board BULLETIN

Strain will increase rapidly but taper off during the period of primary creep. Operation in the period of secondary creep is approximately linear and can be predicted. Operation in the period tertiary creep is not recommended, as the strain can increase very rapidly. Not all materials respond the same. Test data are extremely important.

High temperatures that are over about 1/3 of the melting temperature of the metal present the possibility of creep and creep-fatigue. Temperature limits in the American Society of Mechanical Engineers (ASME) *Boiler and Pressure Vessel Code* (BPV Code), Section III, Division 1 [1] are currently limited to 700 °F (370 °C) and 800 °F (425 °C) for carbon, low alloy, and high tensile steels and austenitic steels, respectively. For the pressure-retaining components, ASME has developed ASME BPV Code, Section III, Division 5 [2] for the design of components, such as vessels, heat exchangers, pump casings, and valve bodies, for high temperature reactors. The materials for pressure boundary components in the ASME BPV Code, Section III, Division 5 [2] are currently limited to the following choices:

- 304 Stainless Steel (SS)
- 316 SS
- Gr91
- A617
- 800H
- 2-1/4 Cr-1 Mo

Design in accordance with ASME BPV Code, Section III, Division 5 [2] does not guarantee the materials will function to support successful operation of components used for non-pressure retaining functions. Non-pressure retaining materials are not restricted to those limited in the

ASME BPV Code. Non-pressure boundary components will still have the same issues that need to be considered in the design, such as very high thermal expansion, creep, and creep-fatigue. Increased strain without an increase in applied stress can impact pump shafts, valve stems, etc. The owner will need to ensure these materials are properly evaluated, designed, and tested to allow operation under the higher temperature and environmental conditions faced in advanced reactors. These components as well as seals, bushings, packing, and gaskets will still require evaluation and testing by owners and manufacturers to ensure the proper materials and component design are used to ensure compatibility with the coolant and adequate performance at the design and operating conditions.

b. Operating Characteristics

In addition to the much higher operating temperatures, the operating vision for several of the advanced reactor designs is to operate for several years between refueling outages, or to not require refueling outages at all. Some reactors are designed to be refueled on line, while others have an initial fuel loading that will last for the entire life of the plant. Others yet have operating cycles like those of the current reactor operating fleet. This will need to be addressed in the required frequency to perform IST activities. Currently, IST programs are based on testing on a quarterly frequency or on a refueling outage frequency if tests cannot be completed while the reactor is on line. With advanced reactors, outages may not occur for 10 to 20 years or more. Shutdowns may occur as needed for repairs; however, main systems may only be placed in what current reactors would consider a hot standby condition. The coolant loops may remain very hot during these conditions. Access to a system that operates at 600 ºC to 950 ºC (1100-1750 ºF) will require very specialized safety considerations, if access can be provided at all. Today's practices of installing gauges or instrumentation to support periodic tests may be impractical or impracticable for the advanced reactors. The requirements to conduct IST activities on a two-year refueling outage frequency need to be evaluated to determine if alternate means of monitoring equipment performance can be used or if plants need to come off-line periodically to ensure the continued adequate performance of equipment which is used to assure safety of the reactor.

c. Inservice Inspection (ISI)

ASME has developed the Reliability Integrity Management program to address inservice inspection (ISI) in advanced reactors. This is located in ASME BPV Code, Section XI, Division 2 [3]. The NRC has not reviewed and endorsed this division of the ASME BPV Code at this time. The approach is based on a probabilistic risk assessment (PRA) which leads to the establishment of reliability targets for components, and from the reliability targets, strategies are developed to ensure the equipment within the scope meets the reliability targets. These strategies consist of the following factors: design strategies, fabrication procedures, operating practices, preservice and inservice examinations, testing, monitoring and non-destructive examinations, and maintenance and repair. The strategies could apply one or a combination of these items. Several different factors could be included to ensure the reliability targets are met.

d. Licensing Approaches

The licensing modernization project is a different approach to licensing new reactors that may be used by some of the designers of advanced reactors. This approach relies heavily on PRA activities. The approach is outlined in Nuclear Energy Institute (NEI) 18-04, "Modernization of Technical Requirements for Licensing of Advanced Non-Light Water Reactors, Risk-Informed Performance-Based Technology Inclusive Guidance for Non-Light Water Reactor Licensing Basis Development," [4] and can be used to establish the safety classification and performance criteria for structures, systems, and components (SSCs). Three classifications result, safety-related, non-safety related with special treatment, and non-safety related with no special treatment. To which category a component belongs, depends upon what functions the component performs. Those components which perform a risk significant function to mitigate the consequences of design-basis events within the licensing basis and to mitigate design-basis accidents to within required dose limits would be safety-related. The applicable safety-related SSCs should be qualified in accordance with ASME Standard QME-1, "Qualification of Active Mechanical Equipment Used in Nuclear Facilities."

Those non-safety related SSCs that are relied on to perform risk-significant functions would fall into the non-safety related with special treatment category. Depending on the function, some of these components may need to be qualified and have some IST activities to demonstrate the functions can be satisfied. These would be part of the special treatment that is applied to the applicable components.

The third category of non-safety related with no special treatment is for components that do not fit in the above categories. No special treatment would be expected for these components.

The NRC published draft regulatory guide (DG) 1353, "Guidance for a Technology-Inclusive, Risk-Informed, and Performance-Based Methodology to Inform the Licensing Basis and Content of Applications for Licenses, Certifications, and Approvals for Non-Light Water Reactors," [5] in the *Federal Register* on May 3, 2019, for public comment. This DG endorses with clarifications as detailed in the DG, the principles and methodology in NEI 18-04, Rev. 0, as one acceptable method for determining the appropriate scope and level of detail for parts of applications for licenses, certifications, and approvals for non-LWRs.

3. Results and Discussion

Much of the following information stems from a document prepared by the U.S. Nuclear Regulatory Commission, "Advanced Non-Light-Water Reactors Materials and Operational Experience," March 2019 [6].

With the increases in operating temperatures above those of current light water reactors, the types of lubricants that are typically used will need to be carefully reviewed to determine if they can withstand these higher temperatures. The use of shrink-fit parts may not be an appropriate practice in the higher temperature environments. Due to the higher temperatures, or transients, the shrink-fit parts could loosen.

While the coolants used in advanced reactors may not present any significant corrosion concerns in their pure form, contaminants could cause bi-products that are very corrosive and cause rotating equipment to bind. Mechanical components can be affected by particles carried in the coolant. Graphite dust particles were the cause of filter overloading in helium gas compressors, leading to failure and frequent replacement of the compressors.

In other operating experience, oil seals in helium gas compressors have also caused problems. Operation at high speeds caused leakage. The high-speed operation resulted in the seals exceeding their tribology limits. Hydraulics and oils should be avoided if possible. In other circulating equipment, bearing lubrication systems could not support the weight without reaching a minimum speed, resulting in damage during start-up of the component. In another instance, hydraulic fluid leaked from a valve causing a fire. This was from a relief valve in the hydraulic system opening from a pressure surge. The potential for fire from leaking fluids and lubricants needs to be considered in the design stage.

The environment of the advanced reactors increases the difficulty in making repairs. Special considerations are needed in sodium-cooled reactors, as sodium is a volatile substance in the presence of air and moisture. Therefore, the reliability of mechanical equipment is essential to avoid the need for complicated maintenance activities.

The above information shows that there are several challenges regarding Advanced Non-Light Water Reactors. Even so, there are also some real IST program benefits with these types of reactors. Many of the systems rely on passive components to perform the critical functions of decay heat removal. The fuel typically used has a much higher melting point preventing the release of radionuclides. Therefore, higher differential temperatures can be tolerated to allow for conduction and natural convection of decay heat, thus not requiring emergency core cooling systems in several of the designs.

However, for those designs that do rely on valves to change position or pumps to move fluids, challenges are presented to design, qualify, and test the materials in those components to be able to ensure proper performance.

Reliance on PRA to establish the scope of components within the IST program will probably result in much fewer components within the program. However, some of the benefits of a strong component qualification program and IST program may be beneficial for non-scope components from an economic consideration.

4. Conclusion

Based on the discussions above, there will be many differences between the current operating fleet of light water reactors and the design and operation of the Advanced Non-Light Water Reactors. To summarize, these differences include:

- Refueling schedules
- Operating temperatures and pressures
- Coolant types
- Reliance on passive components
- Licensing methodology

The IST requirements will need to take these differences into consideration when developing the standards for testing and qualification of components to assess their operational readiness.

While there is not a great wealth of operating experience for advanced non-light water reactors, the limited amount that is available can provide insights on past issues to prevent these from recurring.

Acknowledgements

Thomas Scarbrough and Robert Wolfgang for editorial enhancements and creative suggestions. The NRC Office of Nuclear Regulatory Research for investigating material and operational issues from domestic and international advanced reactor operations.

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The 2022 Symposium on OM Code (formerly Valves, Pumps, Snubbers and Inservice Testing) for operating and new reactors, jointly sponsored by the American Society of Mechanical Engineers and the U.S. Nuclear Regulatory Commission, provides a forum for exchanging information on technical, programmatic, and regulatory issues associated with in service testing programs at nuclear power plants, including the design, operation and testing of valves, pumps, and dynamic restraints (snubbers). The symposium provides an opportunity to discuss improvements in design, operation, and testing of valves, pumps, and dynamic restraints that help to ensure their reliable performance. The participation of industry representatives, regulatory personnel, and consultants ensures the presentation of a broad spectrum of ideas and perspectives on the improvement of testing programs and methods for valves and pumps at nuclear power plants.

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