ASME OM-S/G–2007
(Revision of ASME OM-S/G–2003)

Standards and Guides for Operation and Maintenance of Nuclear Power Plants

AN AMERICAN NATIONAL STANDARD

The American Society of Mechanical Engineers

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ASME issues written replies to inquiries concerning interpretations of technical aspects of this Standard. The interpretations will be included with the above addenda service and are published on the ASME Web site under the Committee Pages at http://cstools.asme.org as they are issued.

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The American Society of Mechanical Engineers
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(A detailed Contents precedes each OM-S/G–2007 Part.)

FOREWORD

The Committee on Operation and Maintenance of Nuclear Power Plants (O & M Committee) was formed in June 1975 when the N45 Committee was disbanded. The N45 Committee was established by the American National Standards Institute (ANSI) and was officially known as the Committee N45 on Reactor Plants and Their Maintenance. The N45 Committee was chartered to promote the development of standards for the location, design, construction, and maintenance of nuclear reactors and plants embodying nuclear reactors, including equipment, methods, and components. ASME assumed the secretariat of several of the N45 committees that related to the requirements contained in Sections III and XI of the ASME Boiler and Pressure Vessel Code (hereinafter referred to as the BPV Code).

The charter of the O & M Committee, as approved by the ASME Board on Nuclear Codes and Standards, is as follows: To develop, revise, and maintain Codes, Standards, and Guides applicable to the safe and reliable operation and maintenance of nuclear power plants.

The O & M Committee was given responsibility to review Section XI and determine where O & M standards could replace current Section XI requirements. The major areas in Section XI identified as requiring O & M standards development were Article IWP, Inservice Testing of Pumps, and Article IWV, Inservice Testing of Valves. To facilitate development of standards in these areas, Section XI, Subgroup on Pumps and Valves, was transferred to the O & M Committee in 1979 as the O & M Working Group on Pumps and Valves under the Subcommittee on Performance Testing. A new Section XI, Working Group on Pumps and Valves, was established in 1984 to review the O & M standards on pumps and valves to assure that they will be acceptable to Section XI.

The O & M Committee operated with two Subcommittees that were responsible for the development of all standards within the Committee. The charters for the two Subcommittees were adopted in October 1975 by the O & M Main Committee.

(a) Subcommittee on Vibration Monitoring. The following was the charter of this Subcommittee:

(1) Describe acceptable types and accuracies of vibration-measuring devices for the types of vibration to be measured.

(2) Discuss fixed and removable measuring devices for long-term and periodic testing.

(3) State minimum objectives of vibration-monitoring systems to include ability to detect cross-structural dynamic instabilites, as well as steady-state vibration response of significant levels.

(4) Include discussion of conditions under which vibration monitoring will be conducted (cold or hot functional) and methods for correlating data with the hot functional condition.

(5) Describe minimum acceptable types and numbers of readout devices.

(b) Subcommittee on Performance Testing. The following was the charter of this Subcommittee:

(1) Identify, develop, maintain, and review codes and standards that are considered necessary for the reliable operation and maintenance of nuclear power plant equipment, particularly as they relate to start-up and periodic performance and functional testing and monitoring of systems and components.

(2) The above includes the establishment of test objectives, test intervals, test methods, test data requirements, as well as the analysis and acceptability of test results and the course of action to be pursued when test results are unacceptable.

Five separate standards published in 1981 and 1982 were consolidated into a single publication, ASME/ANSI OM-1987.

The ASME Board on Nuclear Codes and Standards recognized that O & M is the appropriate committee to establish inservice testing requirements (IST) and voted to proceed with making the O & M Standard stand on its own, with the objective of eventual deletion of IST from Section XI of the BPV Code when appropriate. A transition was implemented in which Parts 1, 4, 6, and 10 of ASME/ANSI OM-1987 (with the three published Addenda: OMa-1988, OMb-1989, and OMc-1990) were incorporated into ASME OM Code–1990, Code for Operation and Maintenance of Nuclear Power Plants. Parts 2, 3, 5, 7, 8, 13, and 16 were incorporated into ASME OM-S/G–1990, Standards and Guides for Operation and Maintenance of Nuclear Power Plants. The transition did not result in technical changes to the existing IST requirements.

This publication was developed and is maintained by the ASME Committee on Operation and Maintenance of Nuclear Power Plants. The Committee operates under procedures accredited by the American National Standards Institute as meeting the criteria of consensus procedures for American National Standards. A previous edition, OM-S/G–1994, was published in 1995. OM-S/G–1997 was approved by the ASME Board on Nuclear Codes and Standards and was subsequently approved by the American National Standards Institute on January 30, 1997.

The OM-S/G–2003 edition consists of the 2000 Edition, the 2001 and 2002 Addenda, and other corrections and revisions. OM-S/G–2003 was approved by the ASME Board on Nuclear Codes and Standards and was subsequently approved by the American National Standards Institute on June 4, 2003.

OM-S/G–2007 was approved by the ASME Board on Nuclear Codes and Standards and was subsequently approved by the American National Standards Institute on August 17, 2007.

PREPARATION OF TECHNICAL INQUIRIES TO THE COMMITTEE ON OPERATION AND MAINTENANCE OF NUCLEAR POWER PLANTS

INTRODUCTION

The ASME Committee on Operation and Maintenance of Nuclear Power Plants meets regularly to conduct standards development business. This includes consideration of written requests for interpretations and revisions to operation and maintenance standards and guides and development of new requirements as dictated by technological development. The Committee's activities in this latter regard are limited strictly to interpretations of the requirements or to the consideration of revisions to the present requirements on the basis of new data or technology. As a matter of published policy, ASME does not "approve," "certify," "rate," or "endorse" any item, construction, proprietary device, or activity and, accordingly, inquiries requiring such consideration will be returned. Moreover, ASME does not act as a consultant on specific engineering problems or on the general application or understanding of the Standard requirements. If, based on the inquiry information submitted, it is the opinion of the Committee that the inquirer should seek assistance, the inquiry will be returned with the recommendation that such assistance be obtained.

All inquiries that do not provide the information needed for the Committee's full understanding will be returned.

INQUIRY FORMAT

Inquiries shall be limited strictly to interpretations of the requirements, or to the consideration of revisions to the present requirements on the basis of new data or technology.

Inquiries shall be submitted in the following format:

(a) Scope. The inquiry shall involve a single requirement or closely related requirements. An inquiry letter concerning unrelated subjects will be returned.

(b) Background. State purpose of the inquiry, which would be either to obtain an interpretation of the Standard requirement or to propose consideration of a revision to the present requirements. Provide concisely the information needed for the Committee's understanding of the inquiry (with sketches as necessary), being sure to include references to the applicable standard or guide, edition, addenda, part, appendix, paragraph, figure, and/or table.

(c) Inquiry Structure. The inquiry shall be stated in a condensed and precise question format, omitting superfluous background information, and, where appropriate, composed in such a way that "yes" or "no" (perhaps with provisos) would be an acceptable reply. This inquiry statement should be technically and editorially correct.

(d) Proposed Reply. State what it is believed that the Standard or Guide requires. If, in the inquirer's opinion, a revision to the Standard or Guide is needed, recommended wording shall be provided.

(e) The inquiry shall be submitted in typewritten form; however, legible, handwritten inquiries will be considered.

(f) The inquiry shall include name and mailing address of the inquirer.

(g) The inquiry shall be submitted to the following address: Secretary, Committee on Operation and Maintenance of Nuclear Power Plants, The American Society of Mechanical Engineers, Three Park Avenue, New York, NY 10016-5990.

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PREFACE

ORGANIZATION OF THIS DOCUMENT

This document is arranged into Standards and Guides, subdivided into Parts as follows:

Standards

Part 2	Performance Testing of Closed Cooling Water Systems in LWR Power Plants
Part 3	Requirements for Preoperational and Initial Start-up Vibration Testing of Nuclear Power Plant Piping Systems
Part 12	Loose Part Monitoring in Light-Water Reactor Power Plants
Part 16	Performance Testing and Inspection of Diesel Drive Assemblies in LWR Power Plants
Part 21	Inservice Performance Testing of Heat Exchangers in Light-Water Reactor Power Plants
Part 24	Reactor Coolant and Recirculation Pump Condition Monitoring
Part 25	Performance Testing of Emergency Core Cooling Systems in Light-Water Reactor Power Plants
Part 26	Determination of Reactor Coolant Temperature From Diverse Measurements

Guides

Part 5	Inservice Monitoring of Core Support Barrel Axial Preload in Pressurized Water Reactor Power Plants
Part 7	Requirements for Thermal Expansion Testing of Nuclear Power Plant Piping Systems
Part 11	Vibration Testing and Assessment of Heat Exchangers
Part 14	Vibration Monitoring of Rotating Equipment in Nuclear Power Plants
Part 17	Performance Testing of Instrument Air Systems in Light-Water Reactor Power Plants
Part 19	Preservice and Periodic Performance Testing of Pneumatically and Hydraulically Operated Valve Assemblies in Light-Water Reactor Power Plants
Part 23	Inservice Monitoring of Reactor Internals Vibration in PWR Power Plants

Parts 2, 3, 5, 7, 8, 13, and 16 were previously published in ASME/ANSI OM-1987 up to and including the OMc-1990 Addenda and were incorporated into ASME OM-S/G–1990.

Parts 1, 4, 6, and 10 from ASME/ANSI OM-1987, up to and including the OMc-1990 Addenda, were incorporated into ASME OM Code-1990, as follows:

OM Code Designation	Previous OM-1987 Designation	
Appendix 1	Part 1	Requirements for Inservice Performance Testing of Nuclear Power Plant Pressure Relief Devices
Subsection ISTD	Part 4	Examination and Performance Testing of Nuclear Power Plant Dynamic Restraints (Snubbers)
Subsection ISTB	Part 6	Inservice Testing of Pumps in Light-Water Reactor Power Plants
Subsection ISTC	Part 10	Inservice Testing of Valves in Light-Water Reactor Power Plants

CORRESPONDENCE

Suggestions for improvement of this document or inclusion of additional topics should be sent to the following address: Secretary, Committee on Operation and Maintenance of Nuclear Power Plants, The American Society of Mechanical Engineers, Three Park Avenue, New York, NY 10016-5990.

ADDENDA SERVICE

This edition of ASME OM-S/G includes an automatic addenda subscription service up to the publication of the next edition. The addenda subscription service will include approved new Parts, revisions to the existing Parts, and issued interpretations. The interpretations will be included as part of the addenda service, but are not part of the Standard or Guide.

ASME OM-S/G–2007
SUMMARY OF CHANGES

Following approval by the ASME Committee on Operation and Maintenance of Nuclear Power Plants and ASME, and after public review, ASME OM-S/G–2007 was approved by the American National Standards Institute on August 17, 2007.

ASME OM-S/G–2007 consists of OM-S/G–2003, OMa-S/G–2004, and OMb-S/G–2005; editorial changes, revisions, and corrections; as well as the following change identified by a margin note, **(07)**.

Page	*Location*	*Change*
145	Part 24, 9.2.4	Equation corrected by errata

STANDARDS

PART 2

PART 2
Performance Testing of Closed Cooling Water Systems in LWR Power Plants

1 INTRODUCTION

1.1 Scope

This Part establishes the requirements for preservice and inservice testing to assess the operational readiness of certain closed cooling water systems (CCWS) used in LWR power plants.

The CCWS covered are those 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.

This Part establishes test methods, test intervals, parameters to be measured and evaluated, acceptance criteria, corrective actions, and records requirements.

1.2 Owner's Responsibility

This Part requires development of a testing program that verifies CCWS perform in accordance with the system design basis over the life of the plant. Establish this program with the following parts:

(a) Establish system testing boundaries (para. 4).

(b) Identify performance requirements from licensing and design basis documentation (para. 5).

(c) Identify testable characteristics that represent performance requirements (para. 6).

(d) Establish test acceptance criteria for each characteristic (para. 7).

(e) Develop test procedures that include test acceptance criteria and test frequencies, and perform required testing, inspections, and engineering analysis (para. 8).

(f) Evaluate test data, document results, and implement corrective action as appropriate (paras. 9 and 10).

Apply the appropriate quality assurance requirements to this program.

Review industry operating experience as an input to the development of this program. Operating experience provides valuable insight into the CCWS performance requirements, performance characteristics, and test performance that should be considered throughout the various phases of program development.

Develop a test program within the bounds of the plant's design basis; do not violate the plant's design basis as a result of testing under this Part. Consider the required test conditions and the potential consequences of the testing when developing the test program. Develop the test program to minimize the impact to plant risk while the test is being performed. In the event that a specific test within the program would be impractical, cause detrimental interactions, or conflict with the design basis, engineering evaluation or analysis is allowed in lieu of the specific test. Refer to para. 8 for additional guidance.

Procedures or test programs established for other purposes may be used to satisfy testing requirements of this Part to the extent that they meet the requirements of this Part.

2 DEFINITIONS

These definitions are provided to ensure a uniform understanding of selected terms used in this Part.

acceptance criteria: specified limits placed on characteristics of an item, process, or service defined in codes, standards, or other required documents.

accuracy: the closeness of agreement between a measured value and the true value.

actuation levels: a response to defined plant conditions that will control or actuate a desired set of components.

characteristic: a variable or attribute that can be verified by direct measurement or data reduction.

closed cooling water system (CCWS): a closed intermediate heat transfer system between supported structures, systems, and components and the ultimate heat sink.

component: an item such as a vessel, pump, valve, piping products, or core support viewed as an entity for purposes of reporting or analyzing.

design bases: information that identifies the specific functions to be performed by a structure, system, or component of a facility, and the specific values or ranges of values chosen for controlling parameters as reference bounds for designs.

process heat exchanger: a CCWS heat exchanger that rejects heat to the ultimate heat sink.

response time: time elapsed from when the process exceeds a setpoint until the component achieves the required response.

serviced heat exchanger: a heat exchanger in a supported system that rejects heat to the CCWS.

support system: those other systems that are necessary for a given system to perform its intended function.

system: an assembly of components whose functions and limitations are defined in design or system specification documents.

3 REFERENCES

ASME OM-S/G–2000, Part 21, Inservice Testing of Heat Exchangers

ASME OMb-S/G–2002, Part 25, Performance Testing of Emergency Core Cooling Systems in Light Water Reactor Power Plants

4 ESTABLISH SYSTEM TESTING BOUNDARIES

(a) Figure 1 shows a simplified CCWS flow diagram and identifies some major components. Components of the typical CCWS may include the following:

(1) CCWS process pumps

(2) control, isolation, throttling, and relief valves

(3) motor controllers, controls, and protective relays

(4) CCWS surge tank(s)

(5) instrumentation components and control loops including all interlocks and alarm functions

(6) CCWS process heat exchangers and serviced component heat exchangers

(7) CCWS process piping and associated hangers, restraints, and supports

(8) water quality monitoring and control equipment

(9) filters

(b) Establish the system test boundaries for CCWS testing. The test boundaries shall include all CCWS functions described in para. 1.1. The test boundary shall include all equipment required to perform the CCWS function of transferring heat from the supported structures, systems, and components to the ultimate heat sink. This test boundary includes the interfacing heat exchangers for the heat sources and heat sinks for CCWS.

Typical functions include the following:

(1) decay heat removal

(2) containment heat removal

(3) pump and pump driver cooling

(4) room cooler heat removal

(5) chilled water system cooler heat removal

(6) containment high-energy penetration heat removal

(7) reactor support structure cooling

(8) system realignments including isolation of nonessential loops or branches

(9) heat removal and flow for nonessential loads that are not isolated, such as fuel pool cooling, sample coolers, and evaporators

Testing of nonessential loads is only required to the extent of verifying that they do not adversely impact the performance of those portions of CCWS within the scope of this Part. Establishing the test boundary shall consider the interaction of nonessential components of the CCWS that may affect CCWS operation by isolation, leakage, or adding heat loads.

Testing of systems that support CCWS operation, such as chemical addition, makeup, engineered safety features actuation system (ESFAS), or emergency core cooling system (ECCS) actuation logic, is not within the scope of this Part. At the owner's option, portions of CCWS not in the scope of this Part may be tested in accordance with this Part.

5 IDENTIFY SYSTEM PERFORMANCE REQUIREMENTS

Identify system performance requirements within the established test boundaries. Input parameters derived from safety analyses and design basis documentation define the performance requirements. Examples include required heat removal rates from serviced loads, required flow rates to serviced loads, heat exchanger performance, surge tank makeup, system fluid losses, system fluid temperature, and time to reach full pumped flow after system actuation.

Performance requirements shall be consistent with the plant licensing and design bases, including relevant licensing commitments that limit, modify, or clarify system operating requirements. Use source information that defines system performance requirements. Source information may include the following:

(a) nuclear steam supply system design specifications

(b) architect/engineer specifications

(c) Final Safety Analysis Report (FSAR)/ Updated Safety Analysis Report (USAR)

(d) Safety Evaluation Report/Supplemental Safety Evaluation Reports

(e) design basis documentation

(f) vendor correspondence

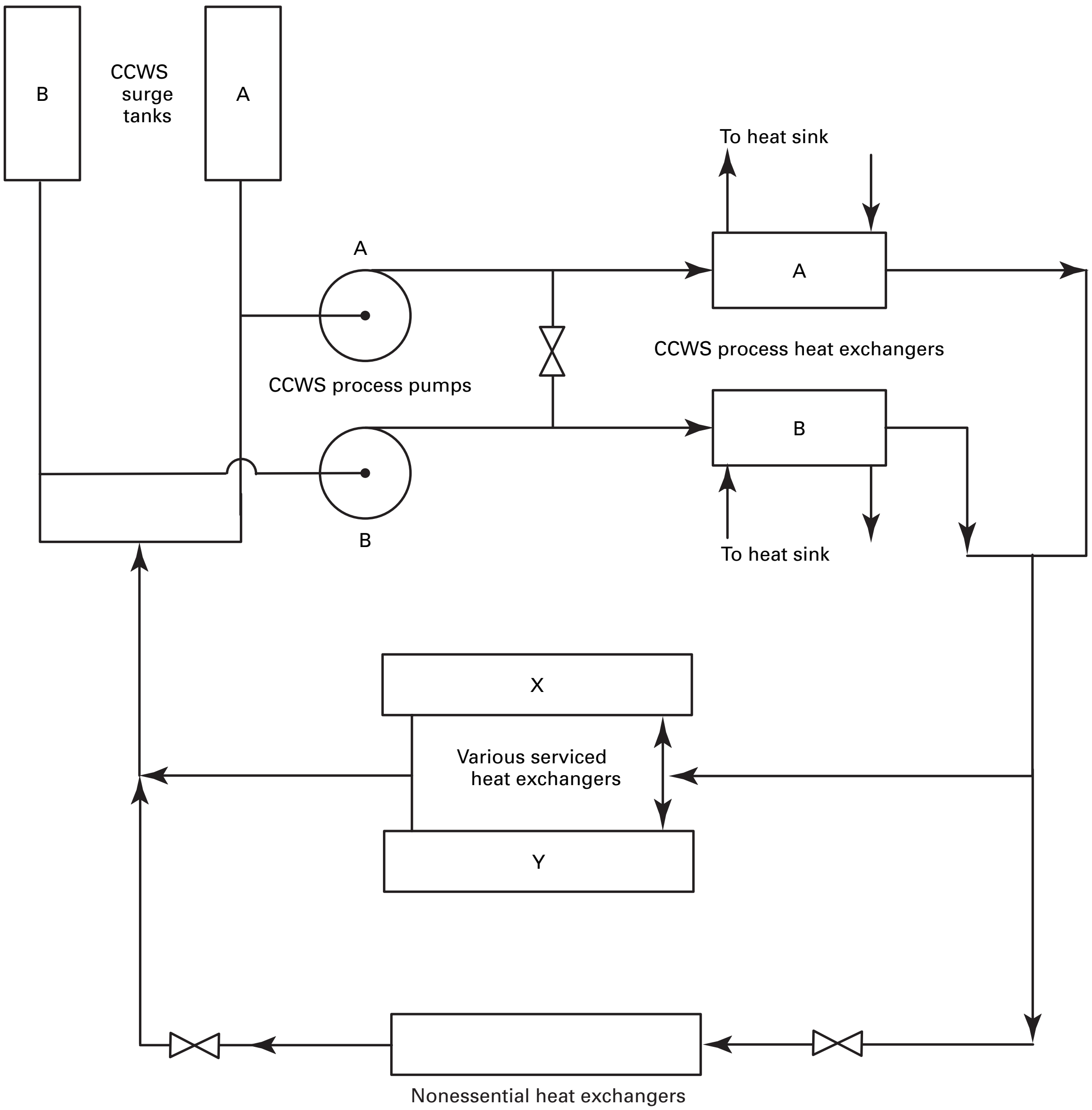
In some cases, it is not practical to directly test each of the performance requirements. In these instances, develop testable system characteristics in accordance with para. 6 that can be used to verify performance requirements.

6 IDENTIFY TESTABLE CHARACTERISTICS THAT REPRESENT PERFORMANCE REQUIREMENTS

(a) Identify testable characteristics that can be used to confirm system performance requirements are met. Use source information that defines system characteristics. Source information, in addition to that identified in para. 5, includes

(1) design calculations

Fig. 1 CCWS Typical Flow Diagram



(2) system descriptions
(3) plant system specific drawings
(4) preoperational tests
(5) design change documentation

(b) System characteristics are variables or attributes that can be determined by direct measurement or data reduction. The system characteristics include component characteristics, instrumentation and control characteristics, and logic characteristics that impact system-level performance.

System characteristics associated with CCWS operation are

(1) system and branch line flows for each system alignment
(2) total CCWS heat rejection capacity
(3) system operating pressures at component elevations where conditions could approach saturation
(4) system operating temperatures
(5) maintaining system operation during system transients such as pump trip in parallel pump operation
(6) pressure differential between the CCWS and the heat sink system is in the appropriate direction
(7) CCWS operation in response to ESFAS or ECCS actuation with and without offsite power

The values of some system characteristics cannot be directly measured but can be calculated. Examples are pump total dynamic head and heat removal rate.

6.1 Component Characteristics

Component characteristics that affect system-level performance shall be included as system characteristics. An example is pump performance required to deliver design flow to the supported components within a defined time interval after an initiating event. Additional system characteristics are flow for serviced and process CCWS heat exchangers and heat removal for CCWS process heat exchangers.

System characteristics associated with CCWS components are as follows:

(a) CCWS pump and driver

(1) net positive suction head (NPSH) for pump performance under system conditions with the least NPSH margin

(2) pump total dynamic head (TDH) versus flow

(3) pump response time (time to reach rated flow)

(4) pump drivers do not trip under flow conditions with the least margin to trip

(5) pump driver (as found) power requirements at all flow conditions are within design assumptions for normal and emergency power

(6) pump performance under parallel pump operation

(b) process heat exchangers

(1) amount of heat required to be transferred

(2) system pressure drop through the heat exchanger

(3) heat exchanger outlet temperature

6.2 Instrumentation and Control Characteristics

Instrumentation and control (I & C) characteristics that affect system-level performance shall be included as system characteristics. These include indication and control of system parameters such as flow, pressure, level, temperature, and component status.

6.3 CCWS Logic Characteristics

CCWS logic characteristics shall be included as system characteristics. CCWS logic is any permissive or interlock that actuates or aligns CCWS fluid systems or mechanical components. CCWS logic does not include ESFAS or ECCS actuation logic. Below are examples of CCWS logic.

(a) logic intended to start standby pumps on flow or pressure demand

(b) logic that causes CCWS components to actuate via an ESFAS or ECCS actuation signal

(c) logic for system realignment to accident mode from any nonsafety or secondary operating mode

(d) logic that actuates surge tank makeup on low level and pressure control

(e) logic for heat exchanger bypass or temperature control

(f) logic associated with control of manually operated components

7 ESTABLISH ACCEPTANCE CRITERIA FOR TESTABLE CHARACTERISTICS

Establish acceptance criteria for each system characteristic derived in accordance with para. 6. Each system characteristic has analysis limits that are documented in the plant design or licensing basis. Develop test acceptance criteria from these limits that account for

(a) differences between analysis and test considering system configuration and boundary or process fluid conditions. Since system testing under accident conditions may be impractical, acceptance criteria must be developed by associating practical test conditions to accident analysis limits. For example, the heat load from initiating events may not be achievable during test conditions.

(b) test instrument loop accuracy. Accomplish this by adjusting either the measured data or the analysis limits. Refer to Appendix B, para. B-4 of ASME OM-S/G Part 25 [Reference 3(b)] for an example of this adjustment process for pump TDH versus flow. Refer to Appendix C of ASME OM-S/G Part 25 for guidance on test instrument accuracy.

8 DEVELOP TEST PROCEDURES AND PERFORM TESTING, INSPECTIONS, AND ENGINEERING ANALYSIS

Develop and approve test procedures to verify that acceptance criteria derived in accordance with para. 7 are met. Organizations responsible for maintaining the design basis shall participate in developing test acceptance criteria and procedures. Use available operating experience information; industry and government agency experience reports and databases give additional insights into system operation and testing.

Perform testing at plant conditions as close as practical to those expected during system operation. Identify test conditions that are different from conditions with least margin (e.g., temperature and pressure) when testing at least-margin conditions is not practical or could potentially damage equipment. Perform analysis to account for differences between least-margin and test conditions.

Consider the required test conditions, detrimental interactions, and potential consequences of testing when developing the test procedure. Evaluate the risk impact of testing, in accordance with existing plant risk management programs, and schedule the test performance to minimize the impact to plant risk. Portions of the system test may be performed at different plant operating modes consistent with managing plant risk.

This Part does not require simultaneous testing of all system components, subsystems, and their support systems. A logical combination of several separate tests is acceptable, however, integrate the testing where practical. For example, the thermal and hydraulic performance on the CCWS process heat exchangers can be determined under different conditions and combined by evaluation to demonstrate acceptable system performance. If separate tests are used to collect data for specific characteristics, analyze these test results to correlate them to results that would have been obtained under simultaneous testing. Ensure all interfaces are properly tested and verified. Operation of the supported (first line) systems may not be necessary. Credit for other testing, such as component testing performed under guidance from other standards, can be used to demonstrate proper system performance.

Data from plant transients or inadvertent system actuations may be used if necessary analyses and supporting documentation are available. If the system is in continuous operation throughout the full range of reactor operation, performance adequacy can be determined by monitoring of the system instrumentation. Normal periodic data logging by various means provides trend data for evaluation of heat exchanger fouling, pump wear characteristics, or branch flow changes.

Engineering evaluations may be performed if integrated testing is not practical. Consider the required test conditions and the potential consequences of the testing in the evaluation of practicality. Use testing rather than evaluation wherever possible.

This Part does not identify nonsystem-level testing of components, instrumentation, and controls. It is assumed that applicable codes and standards that define such testing have been implemented. Verifying test acceptance criteria in accordance with this Part does not provide relief from meeting more limiting criteria associated with such codes and standards.

If tests are performed at conditions different from those assumed in the calibration process for the instruments, recalibrate the instruments for the test conditions, use alternate instruments, or adjust the data to compensate for this difference.

8.1 Preservice Testing

Develop and conduct tests to measure system performance. The test results are used to determine if system, component, I & C, and logic characteristics meet the associated acceptance criteria. The following paragraphs provide requirements for preservice testing of some of the CCWS system characteristics described in para. 6.

8.1.1 Preservice Test Prerequisites. Identify prerequisites to preservice testing to ensure that the system is functional. Perform prerequisites in any order and overlap component and logic testing sufficiently to verify proper installation. Verify that the following prerequisites, at a minimum, have been met prior to performance of the preservice tests:

(a) Electrical systems have been tested, including protective devices.

(b) CCWS logic has been verified to function properly without actual starting of major components.

(c) Control, alarm, and indication instrumentation loops have been calibrated.

(d) System flushing has verified system cleanliness.

(e) Temporary construction components such as strainers and jumpers have been removed or have been evaluated as required to support testing.

(f) Required pipe supports have been installed.

(g) System and components have been filled and vented.

(h) System pressure tests have been completed satisfactorily.

(i) Valves stroke when operated by control switches.

(j) Pump and motor checkouts have been completed per vendor recommendations, including proper rotation checks.

(k) Valve lineups are complete and will ensure that pump minimum flow and runout is met and any flow limits on heat exchangers will not be exceeded.

(l) Required chemical control has been established.

(m) Required support systems are available to support system testing.

8.1.2 Preservice Performance Test. Develop and conduct tests to measure system performance. The test results are used to determine the system, component, I & C, and logic characteristics meet the associated acceptance criteria. The following paragraphs provide requirements for preservice testing of some of the CCWS system characteristics described in para. 6.

During pump operation, monitor the system for unacceptable noise, vibration, or cavitation. During all specified modes of system operation, check that hot support settings are within allowable limits after thermal expansion.

Verify that the CCWS is in the normal system standby alignment or operation. Simulate an emergency actuation signal. Verify that all valves realign to the required accident position and that the associated CCWS pumps are operating. Verify system flow balancing for heat transfer requirements is maintained.

Operate CCWS in each required cooling water alignment and pump combination as allowed by plant design. Test each CCWS train as close as practical to design conditions, however, all heat loads are not required to be in service simultaneously. Verify that the required flow is achieved on each branch or serviced component of CCWS.

Address the following requirements for each applicable operating mode:

(a) Test integrated CCWS operation in conjunction with other systems that could interact with CCWS during accident conditions. For example, branch flows that

are not isolated need to be considered for flow diversion and heat load addition.

(b) Test for adequate NPSH and acceptable pressure drops in suction lines and valves from the sources to the pump suction under maximum flow conditions.

(c) Verify automatic start of standby pumps and automatic alignment of standby heat exchangers.

(d) Verify that a single or multiple pump trip in a system using pumps operating in parallel will not result in an electrical overload trip of the operating pump/motor, runout conditions on a pump, or NPSH problems for the remaining pump(s).

(e) Verify that for the set throttle valve positions or restriction orifice sizes that any pump combinations will not result in

(1) inadequate or excess flow conditions to serviced components

(2) pump flow less than minimum required flow

(f) Verify that system response to design transients, including loss of offsite power, is adequate.

(1) The system realigns without loss of function due to voiding, water hammer, or draining of the surge tank.

(2) Stroke times of boundary valves are within design requirements to ensure that system operation is not compromised for postulated design transients.

(g) Verify operation of bypass temperature or pressure control systems, including surge tank pressure control systems, where provided.

(h) Check hot side to cold side pressure differential for the CCWS process heat exchangers to ensure pressure differential is within the design limit and in the appropriate direction.

(i) Verify proper operation of manually controlled components.

(j) Verify proper operation of automatic surge tank makeup functions. Demonstrate manual makeup where credited. Verify that level instrumentation and alarms function properly to allow appropriate response to a loss of surge tank level.

(k) Verify system leakage, including pressure boundary and isolation valves, is within design assumptions.

Perform final system flow balancing with available or simulated heat loads. Heat loads not available during this test should be estimated and allowed for in the system flow balancing. Repositioning throttle valves or resizing flow orifices could significantly affect the flow balance or previous test results. Perform the applicable flow testing when such modifications have been made.

Verify CCWS process heat exchangers are tested in accordance with ASME OM-S/G Part 21 [Reference 3(a)]. Using the results of the Part 21 testing and the testing in this Part, perform an evaluation to confirm that the CCWS under least margin operating conditions will meet design basis assumptions. If the evaluation results in required changes to the system, then reperform the appropriate tests of this Part or Part 21.

8.1.3 Preservice Test Interval. Perform preservice tests prior to plant fuel load. Portions of the preservice testing may be deferred if required conditions for testing cannot be met until after plant fuel load. Base deferral of the testing on engineering evaluation to determine the impact on plant safety. Perform deferred testing as soon as practical after the required plant conditions have been met.

8.2 Inservice Testing

Develop and conduct tests to measure system performance. The test results are used to determine the system, component, I & C, and logic characteristics meet the associated acceptance criteria. The following paragraphs provide requirements for inservice testing of some of the CCWS system characteristics described in para. 6.

8.2.1 Inservice Performance Test. Verify that the CCWS is in the normal system alignment. Simulate an emergency actuation signal. Verify that all valves realign to the required accident position and that the associated CCWS pumps are operating. Verify system flow balancing for heat transfer requirements is maintained.

Operate CCWS in the accident alignment with each required cooling water branch and pump combination as allowed by plant design. Test each CCWS train as close as practical to design conditions, however, all heat loads are not required to be in service simultaneously. Verify that the required flow is achieved on each branch or serviced component of CCWS.

Address the following requirements for each applicable operating mode:

(a) Test integrated CCWS operation in conjunction with other systems that could interact with CCWS during accident conditions. For example, branch flows that are not isolated need to be considered for flow diversion and heat load addition.

(b) Test for adequate NPSH and acceptable pressure drops in suction lines and valves from the sources to the pump suction under maximum flow conditions.

(c) Verify automatic start of standby pumps and automatic alignment of standby heat exchangers.

(d) Verify that a single or multiple pump trip in a system using pumps operating in parallel will not result in an electrical overload trip of the operating pump/motor, runout conditions on a pump, or NPSH problems for the remaining pump(s).

(e) Verify that for the set throttle valve positions or restriction orifice sizes that any pump combinations will not result in

(1) inadequate or excess flow conditions to serviced components

(2) pump flow less than minimum required flow

(f) Verify that system response to design transients, including loss of offsite power, is adequate.

(1) The system realigns without loss of function due to voiding, water hammer, or draining of the surge tank.

(2) Stroke times of boundary valves are within design requirements to ensure that system operation is not compromised for postulated design transients.

(g) Verify operation of bypass temperature or pressure control systems, including surge tank pressure control systems, where provided.

(h) Check hot side to cold side pressure differential for the CCWS process heat exchangers to ensure pressure differential is within the design limit and in the appropriate direction.

(i) Verify proper operation of manually controlled components.

(j) Verify proper operation of automatic surge tank makeup functions. Demonstrate manual makeup where credited. Verify that level instrumentation and alarms function properly to allow appropriate response to a loss of surge tank level.

(k) Verify system leakage, including pressure boundary and isolation valves, is within design assumptions.

(l) Verify proper CCWS heat exchanger performance using methods described in ASME OM-S/G Part 21 [Reference 3(a)].

8.2.2 Inservice Test Interval

(a) Establish a 5-year ± 25% initial baseline test interval for the CCWS inservice testing described in para. 8.2. After each test, establish the subsequent test interval based on evaluation of the test results performed in accordance with para. 9. If the test interval is extended, the maximum allowable interval is 10 years.

(b) Test process heat exchanger heat removal capability at the interval described in ASME OM-S/G Part 21 [Reference 3(a)].

(c) Perform the applicable portions of para. 8.2 prior to returning the system to service following replacement, repair, maintenance, or modification to CCWS components or systems that could affect the ability to meet system performance requirements defined in para. 5. Examples of such changes include the following:

(1) replacing valve or valve internals

(2) changing valve throttled position, including limit switch stop settings

(3) resizing system restriction orifices

(4) replacing or trimming the pump rotating element

(5) changing system logic

(6) changing the CCWS flow path

(7) heat exchanger tube plugging

(d) Credit may be taken for testing performed in accordance with other test programs meeting the requirements of this Part.

9 EVALUATE TEST DATA

Evaluate the test data against the acceptance criteria established in accordance with para. 7. If test results fail to meet acceptance criteria, take corrective action. Corrective action shall consist of either of the following:

(a) Perform appropriate remedial actions on the nonconforming component or system, followed by retest.

(b) Perform evaluations to disposition the affected components or nonconforming systems portion. These evaluations shall include refining the analysis on which the acceptance criteria are based such that the measured data meets the revised acceptance criteria and corresponding revision of the design, design basis, and licensing basis. Establish the revised acceptance criteria with sufficient margin to ensure acceptable performance until the next system test.

(c) Evaluate the test data to project future system performance by considering

(1) margin between acceptance criteria and system test results

(2) system performance data trending

(3) modification and maintenance history

(4) internal and external system service conditions (for example biofouling, corrosion, erosion, and wear)

(5) frequency of operation

If the evaluation determines that satisfactory performance is ensured until the next system test, then consider extending the test interval. If the evaluation determines satisfactory performance until the next system test is not ensured, then either restore margin or reduce the test interval to ensure acceptable performance until the next system test.

10 PREPARE DOCUMENTATION

Document the basis for establishing test boundaries, identifying system performance requirements and testable characteristics, establishing acceptance criteria, and developing test procedures. Include in the basis a discussion of test scope decisions including any overlap with other test programs. Retain testing program procedures, results, deficiencies, evaluations, and corrective actions.

PART 3

Figures

Tables

Nonmandatory Appendices

PART 3
Requirements for Preoperational and Initial Start-up Vibration Testing of Nuclear Power Plant Piping Systems

1 SCOPE

This Part establishes the requirements for preservice and initial startup testing to assess the vibration of certain piping systems used in light-water reactor (LWR) power plants. This Part may serve as a guide to assess vibration levels of applicable piping system during plant operation. The piping covered is that 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. This Part establishes test methods, test intervals, parameters to be measured and evaluated, acceptance criteria, corrective actions, and records requirements.

2 DEFINITIONS

These definitions are provided to ensure a uniform understanding of selected terms used in this Part.

ASME B31: ASME Code for Pressure Piping.

ASME BPV Code: ASME Boiler and Pressure Vessel Code.

Design Specification: the document provided by the Owner, as required by NCA-3250 or NA-3250 of the ASME BPV Code, Section III, for the component/system, which contains requirements to provide a complete basis for the construction of the component/system.

design verification: the process of reviewing, confirming, or substantiating a design by one or more methods to provide assurance that the design meets the specified design input.

duplicate: a system built on the basis of a previously used and proven design for which test results are available.

hot shimming: the process of adjusting support and restraint clearances in the hot condition.

initial start-up testing: test activity performed during or following initial fuel loading, but prior to commercial operation. These activities include fuel loading, precritical tests, initial criticality tests, low power tests, and power ascension tests.

maintenance/repair/replacement: actions taken to prevent or correct deficiencies in the system operation.

normal operating conditions: the service conditions the system would experience when performing its intended function.

operational testing: test activities performed subsequent to initial start-up testing, e.g., testing performed during commercial operation of the plant.

Owner: the organization legally responsible for constructing and/or operating a nuclear facility including, but not limited to, one who has applied for or who has been granted a construction permit or operating license by the regulatory authority having lawful jurisdiction.

peripheral equipment: device(s) used in the setup, checkout, or on-site calibration of other VMS devices.

physical units: the engineering units that quantitatively represent the measured variable (e.g., if the measured variable is displacement, the physical units can be inches, mils, feet, or meters).

preoperational testing: test activities performed prior to initial fuel loading.

processing equipment: device(s) used for further handling, reformatting, or manipulation of the transducer output to reduce it to manageable or intelligible information.

prototype: system built on the basis of an original design for which there are no previous system test results available.

quality assurance: all those planned and systematic actions necessary to provide adequate confidence that an item or facility will perform satisfactorily in service.

record drawing set: the set of drawings that define the system's layout and support configuration at the time the system is placed in service for testing.

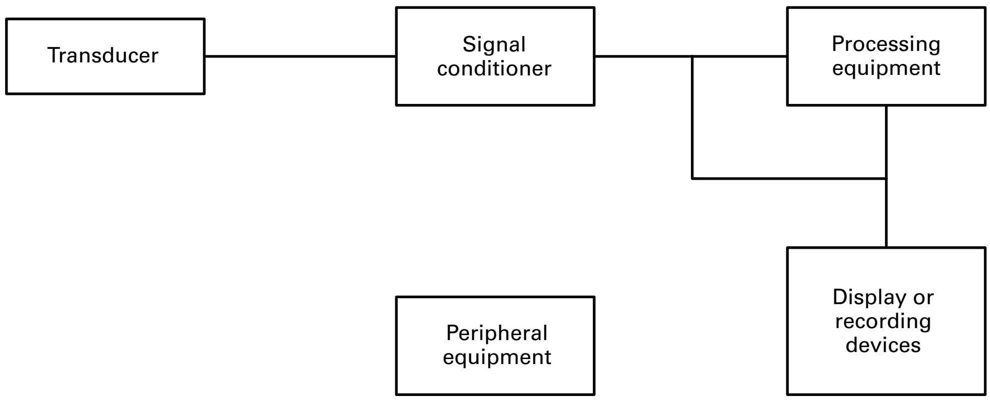
recording and display equipment: recording equipment devices are used for storing signals in a form capable of subsequent reproduction. Display equipment devices are used to obtain a visual representation of a signal (conditioned and/or processed transducer output).

shell-wall vibration: radial vibration of a pipe wall, which typically occurs at high frequencies, characterized by axial and circumferential lobate mode shapes and natural frequencies.

signal conditioner: device(s) used to modify or reformat the transducer output to make it intelligible to or compatible with processing equipment.

steady-state vibrations: repetitive vibrations that occur for relatively long periods of time during normal plant operation.

Fig. 1 Typical Components of a Vibration Monitoring System (VMS)



system: an assembly of piping subassemblies and components whose limits and functions are defined in its Design Specification.

system interconnections: all cables, wires, or mechanical linkages used between the devices comprising the VMS.

system specification: that document that uniquely describes the VMS. The system specification shall contain the information specified in para. 7.2.

test conditions: the conditions experienced by the system when undergoing tests.

test hold points: events in the test program usually associated with system operating conditions for which test information is to be collected, e.g., with the reactor at X% power and with the system at full flow.

test specification: the document(s) prepared by the Owner or his assignee that meet(s) the requirements set forth in para. 3 of this Part.

transducer: a device that converts shock or vibratory motion into an optical, mechanical, or, typically, an electrical signal that is proportional to a parameter of the experienced motion.

transient vibrations: vibrations that occur during relatively short periods of time and result in less than 10^6 stress cycles. Examples of transient sources of vibration are pump actuation and pump switching, rapid valve opening or closing, and safety relief valve operation.

Vibration Monitoring System (VMS): the system comprised of all instrumentation or test equipment used to measure and record the vibration data. It is assumed to have as input the monitored variable (i.e., displacement velocity and acceleration) at the measurement location. The system output is a signal analogous to the measured variable and readily convertible to appropriate physical units. A typical VMS is shown in Fig. 1.

3 GENERAL REQUIREMENTS

The Owner shall determine the portions of piping systems to be tested and shall classify these systems into the vibration monitoring groups defined below. The minimum general requirements for the classification by groups are provided in para. 3.1; however, the Owner may place a system into a more stringent vibration monitoring group (VMG).

Vibration conditions are classified into steady-state and transient vibration categories. A system may be classified into one vibration monitoring group for steady-state vibrations and into another group for transient vibrations. The testing requirements, acceptance criteria, and recommendations for corrective action associated with these categories are provided below. The vibration testing and assessment of vibration levels may be conducted during preoperational and initial start-up testing or during plant operation in accordance with the requirements of the test specification.

For preoperational, initial start-up, and operational testing, a test specification shall be prepared that will include, as a minimum, the following items:

(a) test objectives
(b) systems to be tested (including boundaries)
(c) pretest requirements or conditions
(d) governing documents and drawings
(e) precautions
(f) quality control and assurance (including required documentation and sign-offs)
(g) acceptance criteria
(h) test conditions and hold points
(i) measurements to be made and acceptable limits (including visual observations)
(j) instrumentation to be used (including instrument specifications)
(k) data handling and storage
(l) system restoration

The test specifications shall be written in a manner to ensure that the objectives of the tests are satisfied and that results obtained are accurate or conservative. Prior to testing, an inspection of components and supports shall be made to verify correct installation according to the record drawing set, specifications, and appropriate codes.

When test results are to be correlated to specific analysis, test conditions and measurements should be sufficiently specified to ensure that the parameters and assumptions used in the analysis are not violated. The correlation between test and analysis should confirm the validity of the analysis and should indicate that the analytical results are conservative. If the test results indicate that the analysis is not adequate or when the measured data from the test indicates that the actual forcing function is not conservatively covered by the forcing functions used in the analysis, the analysis should be reconciled.

The vibration monitoring requirements and acceptance criteria are defined in para. 3.2. If the test data exceeds the value specified in the hold point section of the test specification, two options are available: further testing or evaluation to a more rigorous method or corrective action taken, as described in para. 8.

Cognizant engineering personnel shall participate in the development of test specification requirements, selection of instrumentation, establishment of acceptance criteria, review, evaluation, and approval of test results.

Selection of the locations of measuring devices and the type of measurements to be made shall be based on piping stress analysis, response of a similar system, or experience gained through testing of the subject system and shall reflect any unique operational characteristics of the system being tested. Evaluation of the test data shall consider characteristics of the measuring devices used.

3.1 Classification

Piping system vibrations are classified into two categories, steady-state and transient, as defined in para. 2. Within each applicable category, the piping system shall be classified into one of the three vibration monitoring groups according to the criteria presented in paras. 3.1.1 and 3.1.2.

Piping systems that are inaccessible for visual observation or measurement using portable devices, as a result of adverse environmental effects during the conditions listed in the test specification, shall be classified into either VMG 1 or VMG 2.

In addition to the requirements presented in paras. 3.1.1 and 3.1.2, the safety or the power generation function, or both, of the system should also be considered when classifying the system into the vibration monitoring groups.

3.1.1 Steady-State Vibration

3.1.1.1 Vibration Monitoring Group 1. The monitoring program required for systems evaluated in this group typically involves sophisticated monitoring devices and extensive data collection to accurately determine vibratory pipe stresses or other specified component limitations.

Determination of mode shapes, modal response magnitudes, and total system response is possible using these evaluation techniques. When accurate measurement of the system response characteristics is required, the techniques and devices implied by the requirements for this vibration monitoring group shall be employed.

All portions of piping systems that experience steady-state vibrations and meet one of the following requirements shall be classified in VMG 1 and shall meet the acceptance criteria of para. 3.2.1:

(a) piping systems that exhibit a response not characterized by simple piping modes (e.g., piping shell-wall vibrations, as defined in para. 2)

(b) piping systems for which the methods of VMG 2 and VMG 3 are not applicable based on limitations given in paras. 4 and 5

3.1.1.2 Vibration Monitoring Group 2. The methods and devices employed in the evaluation of VMG 2 provide a means of measuring and assessing the piping vibration at a given location.

All portions of piping systems that meet one of the following requirements shall be classified in VMG 2 and shall meet the acceptance criteria specified in para. 3.2.2:

(a) all piping systems that may exhibit significant vibration response based on past experience with similar systems or similar system operating conditions

(b) piping systems for which the method of VMG 3 is not applicable

3.1.1.3 Vibration Monitoring Group 3. The visual method employed in the evaluation of VMG 3 is most fundamental and provides the most simplified means for determining whether any significant vibrations exist in the system. Evaluation of vibration levels using this method is based on experience and judgment and provides an acceptable basis for assessment. If firm quantitative assessments are required, the methods in VMG 1 or VMG 2 should be employed.

All portions of piping systems that meet one of the following requirements shall be classified in VMG 3 and shall meet the acceptance criteria specified in para. 3.2.3:

(a) systems falling in VMG 1 or VMG 2 classification for which measurements or prior test data are available on prototype or duplicate systems and for which the minimum unacceptable vibrations are observable

(b) portions of ASME Classes 1, 2, 3, and ASME B31 piping systems that are not expected to exhibit significant vibrational response based on past experience with similar systems or system operating conditions

Table 1 System Tolerances

System Design Parameters	Allowable Tolerance Range	Units	
		Customary	SI
System flow [Note (1)]	+10%	gpm	m^3/s
Head [Note (2)]	+10%	psi	kPa
Thermal capacity Q [Note (3)]	−10%	Btu/hr	Cal/hr
Overall heat transfer coefficient [Note (4)]	−10%	Btu/hr-ft^2-°F	Cal/hr-cm^2-°C

NOTES:
(1) The upper limit of flow is that which will not produce unacceptable vibration in the heat exchangers in any system flow mode.
(2) The upper limit of head is determined by limiting pressure drop across heat exchanger in any flow mode.
(3) $Q = UA\Delta T$ where U = overall heat transfer coefficient; A = surface area of heat exchanger, ft^2 (cm^2); and ΔT = log mean temperature difference, °F (°C).
(4) The lower U limit is indicative that surface fouling may cause unacceptable thermal capacity in the future.

3.1.2 Transient Vibration. Table 1 presents some examples of transient conditions to which systems may be subjected.

3.1.2.1 Vibration Monitoring Group 1. Portions of piping systems that experience transient vibrations and meet the following requirements shall be classified in VMG 1 and shall meet acceptance criteria specified in para. 3.2.1. Systems that from past plant operation experience are known to experience significant dynamic transient conditions due to the inherent nature of component design, system operation, or system design features, for which a transient analysis is not performed.

3.1.2.2 Vibration Monitoring Group 2. Portions of piping systems that experience transient vibrations and meet the following requirements shall be classified in VMG 2 and shall meet acceptance criteria specified in para. 3.2.2. Systems that are designed and analyzed for known anticipated dynamic loading conditions and for which the applied loading (i.e., fluid or mechanical) is based on methodology that is known to conservatively predict the transient forcing function and corresponding structural response.

3.1.2.3 Vibration Monitoring Group 3. All portions of piping systems that experience transient vibrations and meet the following requirements shall be classified in VMG 3 and shall meet the acceptance criteria specified in para. 3.2.3. Systems that undergo transient vibrations during their operating life (e.g., systems subjected to pump start-up transients, valve opening, or closure) and that by past experience with similar systems or system operating conditions are not expected to exhibit significant vibrational response.

3.2 Monitoring Requirements and Acceptance Criteria

Special attention should be given to the precautions listed in para. 4.3.

The acceptance criteria presented in this paragraph are based on the following list of assumptions. The Owner may invoke less stringent criteria provided sufficient justification is given. More stringent criteria shall be invoked if these assumptions are deemed inappropriate for the system under review.

(a) Assumptions

(1) Vibrations cause maximum stresses within the elastic range; therefore, no penalty for plastic cycling is incurred.

(2) Thermal transient effects, if they exist during the vibration incident, have already been considered in the piping system evaluation.

(3) The membrane stresses caused by pressure fluctuations alone are insignificant in comparison to the stresses caused by the vibratory moments.

(4) The usage factor from the vibration incident does not significantly affect the cumulative usage factor calculated for other predefined transient conditions.

(5) Strain-controlled fatigue curves of the BPV Code, Section III represent the S-N fatigue characteristics for the material and loading considered.

3.2.1 Vibration Monitoring Group 1

3.2.1.1 The vibration response of Group 1 systems shall be evaluated using the methods and devices listed in para. 6 of this Part.

3.2.1.2 For steady-state vibration, the maximum calculated alternating stress intensity S_{alt} should be limited as defined below.

(a) For ASME Class 1 piping systems

$$S_{alt} = \frac{C_2 K_2}{Z} M \le \frac{S_{el}}{\alpha}$$

where

C_2 = secondary stress index as defined in ASME BPV Code, Section III

K_2 = local stress index as defined in ASME BPV Code, Section III

M = maximum zero to peak dynamic moment loading due to vibration only, or in combination with other loads, as required by the system Design Specification

S_{el} = 0.8 S_A, where S_A is the alternating stress at 10^6 cycles in psi (MPa) from ASME BPV Code, Section III, Fig. 1-9.1; or S_A at 10^{11} cycles from ASME BPV Code, Section III, Fig. 1-9.2.2. The user shall consider the influence of temperature on the Modulus of Elasticity.

Z = section modulus of the pipe

α = allowable stress reduction factor: 1.3 for materials covered by ASME BPV Code, Section III, Fig. 1-9.1; or 1.0 for materials covered by ASME BPV Code, Section III, Fig. 1-9.2.1 or 1-9.2.2

(b) For ASME Classes 2 and 3 piping and ASME B31

$$S_{alt} = \frac{C_2K_2}{Z} M \le \frac{S_{el}}{\alpha}$$

where

C_2K_2 = $2i$

i = stress intensification factor, as defined in ASME BPV Code, Section III, Subsections NC and ND or ASME B31

If significant vibration levels are detected during the test program that have not been previously considered in the piping system analysis, consideration should be given to modifying the Design Specification to reverify applicable code conformance.

3.2.1.3 For transient vibrations, the maximum alternating stress intensity should be limited to the value defined below. Before determining the allowable maximum alternating stress intensity, an estimate should be made of the equivalent number of maximum anticipated vibratory load cycles (n).

(a) For ASME Class 1 piping systems, the maximum alternating stress intensity shall be limited to the value that will not invalidate the design basis. If the transient event was not previously considered in the design basis, the event shall be evaluated. The unused usage factor shall be determined from

$$U_v = 1 - U$$

where

U = cumulative usage factor from ASME Class 1 analysis, which excluded vibratory load

The maximum allowable equivalent vibratory load cycles shall be calculated from

$$N_v = \frac{n}{U_v}$$

Using N_v, the maximum alternating stress intensity S_{alt} shall be limited to S_a where

S_a = allowable alternating peak stress value from ASME BPV Code, Section III, Fig. 1-9.1, 1-9.2.1, or 1-9.2.2.

For transient vibrations that were not previously analyzed and for which it is not appropriate to evaluate the load separately, a new fatigue analysis may be required in accordance with Section III of the ASME BPV Code.

(b) For ASME Classes 2 and 3 and ASME B31 piping, the stresses shall be evaluated in accordance with the requirements of para. 3.2.1.2(b). Alternatively, the appropriate ASME code shall be used to evaluate the stresses for transient vibration.

3.2.2 Vibration Monitoring Group 2

3.2.2.1 The vibration response of Group 2 systems should be measured using one or more of the vibration monitoring devices specified in para. 5.

3.2.2.2 For steady-state vibration, the piping vibratory responses of VMG 2 piping shall be evaluated in accordance with the allowable deflection or velocity limits given in para. 5. These limits are based on meeting the stress requirements of para. 3.2.1. If adequate quantitative data cannot be obtained or unacceptable vibration response is indicated by the methods and devices listed in para. 5, the methods and devices of para. 6 may be used.

3.2.2.3 For transient vibration, the criteria of para. 3.2.2.2 for steady-state vibration may be used as a screening tool but may be overly conservative. If these limits are exceeded, the criteria of para. 5.2.3 or the criteria of para. 3.2.1.3 shall be employed.

3.2.3 Vibration Monitoring Group 3

3.2.3.1 The vibration response of Group 3 systems shall be determined by the methods and devices listed in para. 4.

3.2.3.2 If an acceptable level of steady-state or transient vibration is noted, no further measurement or evaluation is required. The observer shall be responsible for assessing whether the observed vibration level is acceptable. The basis for determining whether the vibration level is acceptable shall be consistent with the limits specified in para. 3.2.1.

3.2.3.3 If the level of vibration is too small to be perceived and the possibility of damage is judged to be minimal, the system is acceptable.

The judgment as to acceptability can be made only by the evaluation of *all* the following facts as to their effects on the piping stress:

(a) vibration magnitude and location

(b) proximity to "sensitive equipment"

(c) branch connection behavior

(d) capability of nearby component supports

Any unique operational characteristics of the system shall be considered in the evaluation.

3.2.3.4 If an acceptable assessment of the observed deflections cannot be made, the acceptability of vibration must be based on measured data.

3.2.3.5 If unacceptable vibration levels are indicated by the methods and devices listed in para. 4, the methods and devices of para. 5 may be used.

3.2.4 Qualitative Evaluations. Piping system response must be acceptable based on qualitative evaluations, in addition to meeting the quantitative acceptance criteria defined in para. 3.2. Qualitative evaluations are based on observed response of the piping that address potentially detrimental conditions not explicitly quantified by the acceptance criteria of para. 3.2. Judgments on the acceptability of the observed responses shall be based on comparisons to known acceptable responses. Nonmandatory Appendices G and H provide additional guidance on the use of qualitative evaluations.

4 VISUAL INSPECTION METHOD

4.1 Objective

The acceptability of piping systems in VMG 3 to withstand the effects of steady-state and transient vibrations can be evaluated by observation. Different techniques and simple devices that can be employed in the evaluation as well as some of the possible problems that could be encountered during the preoperational phase and startup of systems are described below.

4.2 Evaluation Techniques

The location or locations of maximum deflection can be ascertained by observation. The magnitude of the displacement may be estimated by the use of simple measurement devices (e.g., rules, optical wedge, and spring hanger scale). When simple measurement devices are used, the precautions of Nonmandatory Appendix A shall be observed. As an aid in developing judgment of the acceptability of observed displacements, simple beam analogies may be used.

4.2.1 Steady-State Vibration. During the preoperational and start-up testing phases of a plant, the piping systems shall be observed during their various modes of operation, as defined in the test specification. The acceptability of the observed vibration shall be determined in accordance with para. 3.2.3.

4.2.2 Transient Vibration. During the preoperational and start-up testing phases of a plant, the piping systems in VMG 3 shall be observed during the transient events as defined in the test specification. The test may be repeated, if necessary, to make the observations at different points. The acceptability of the observed response shall be based on para. 3.2.3.

4.3 Precautions

Below are a few precautions and specific items that should be reviewed.

4.3.1 Vents and Drains. Local vents and drains typically have one or two isolation valves that act as concentrated masses. If they have not been braced, careful attention should be given to vibration in this area.

4.3.2 Branch Piping. Minor mainline vibration may cause branch piping vibration of significant magnitude remote from the branch connection. These lines shall be reviewed together with the system being qualified.

4.3.3 Multiple Pump Operation. In cases where there are several pumps that operate in parallel, the most significant vibration will occur when some combinations of the pumps are operating. These combinations shall be reviewed together with the system being qualified.

4.3.4 Sensitive Equipment. Vibrations that can affect the functionality, operability, and structural capability of sensitive equipment, such as pumps, valves, and heat exchangers, should be closely reviewed.

4.3.5 Welded Attachment. Special consideration shall be given to the areas near the welded attachment in the piping system subjected to vibration. If the welded attachment configuration is such that it could cause local moments in the pipe due to vibration, the effects of local stress should be considered.

5 SIMPLIFIED METHOD FOR QUALIFYING PIPING SYSTEMS

5.1 Steady-State Vibration

There are simplified methods for the evaluation of steady-state vibration of piping systems that will determine if the vibration exceeds an acceptable level. These methods apply to systems that are undergoing steady-state vibration and are accessible for a number of vibration measurements at various points in the piping system. Piping systems that are not suitable or adaptable to these methods may be evaluated by procedures defined in para. 6.

5.1.1 Displacement Method

5.1.1.1 General Requirements. The simplified method requires that vibratory displacement should be determined at representative points on the piping system. The piping system shall be subdivided into sufficient subsystems or vibratory characteristic spans containing appropriate or conservative boundary conditions as described in detail in para. 5.1.1.6(a).

5.1.1.2 Instrumentation. A hand-held or temporarily mounted transducer that is suitable for making

Fig. 2 Deflection Measurement at the Intersection of Pipe and Elbow

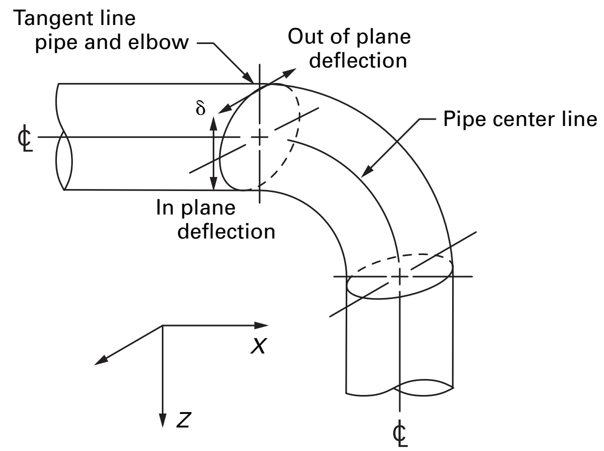
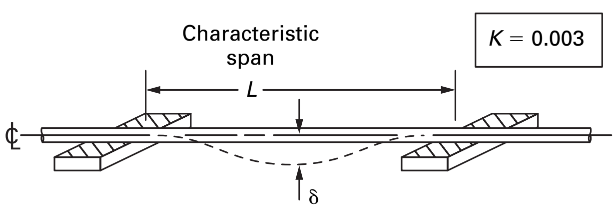


Fig. 3 Single Span Deflection Measurement



multiple measurements of displacement should be used. For example, an accelerometer may be used with velocity and displacement of the acceleration signal obtained by single and double integration, respectively. The precautions on measurement techniques should be observed (para. 7). It is recommended that response frequencies and their relative amplitudes be determined as an aid in verifying the appropriateness of the characteristic span model selected and to assist in determining the source of vibration.

5.1.1.3 Deflection Measurement of Process Piping. Measurements are taken along the piping to measure peak deflection points and to establish node points of minimum deflection. The node points establish the characteristic span lengths. Node points (zero deflection points) are generally found at restraint points, but could be located between constraints on long runs of piping. The deflection limit can be determined from the information presented in Figs. 2 through 9.

5.1.1.4 Deflection Measurement of Branch Piping. Branch piping is attached to process piping and has a smaller diameter than the process piping. Three of the potential problems that can exist are described below.

(a) Branch piping can be excited at or near its resonant frequency by motion of the process piping, fluid pulsation, or other sources. This problem is characterized by

Fig. 4 Cantilever Span Deflection Measurement

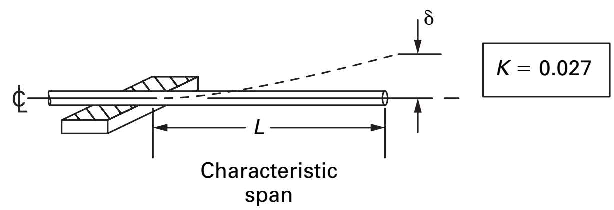


Fig. 5 Cantilever Span/Elbow Span in Plane Deflection Measurement

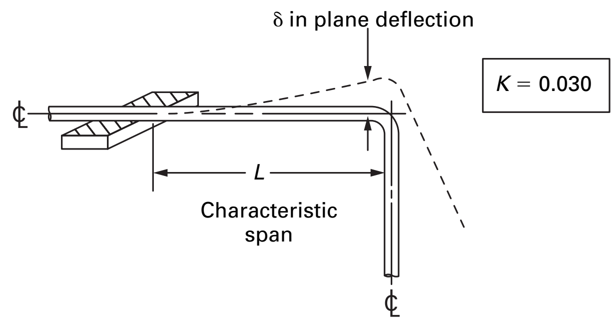


Fig. 6 Cantilever Span/Elbow Guided Span in Plane Deflection Measurement

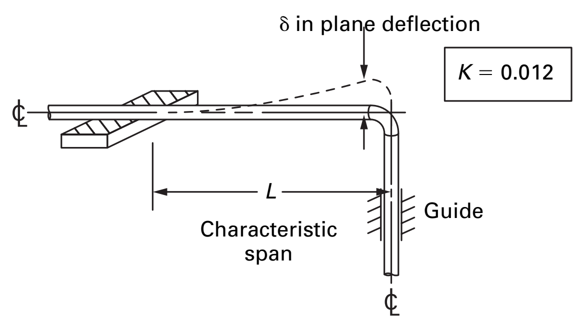
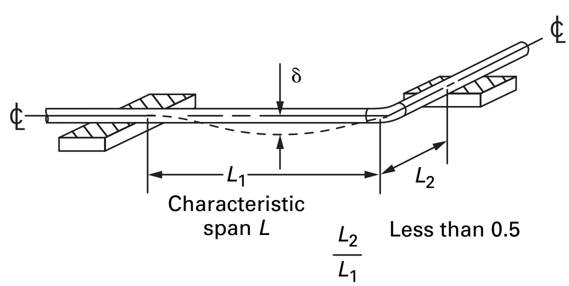
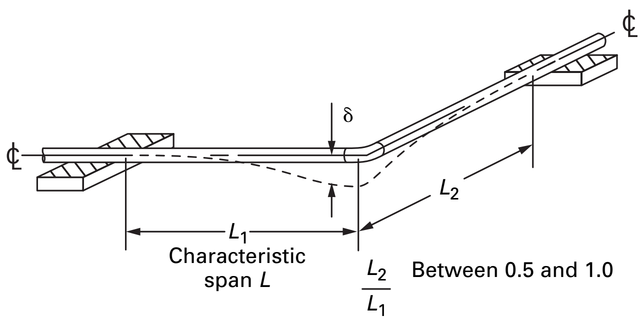


Fig. 7 Span/Elbow Span Out-of-Plane Deflection Measurement, Span Ratio < 0.5



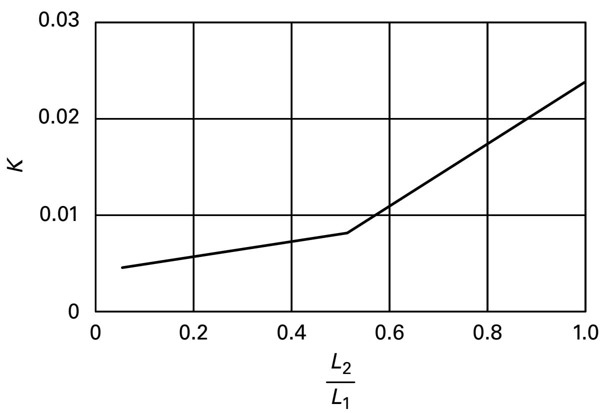
NOTE: See Fig. 9 for *K*.

Fig. 8 Span/Elbow Span Out-of-Plane Deflection Measurement, Span Ratio > 0.5



NOTE: See Fig. 9 for K.

Fig. 9 Span/Elbow Span Out-of-Plane Configuration Coefficient Versus Ratio of Spans



high amplitude vibrations with a clearly defined frequency and mode shape. The amplitude measured on the branch pipe is generally much larger than the process piping. Due to the phasing, the relative motion of the branch pipe to the process pipe is closely approximated by adding the displacement measurement of the process pipe to the motion of the branch pipe. The deflection limits defined in para. 5.1.1.5 are applicable.

(b) The attachment point of the branch pipe with the process line displaces relative to a branch line support. The deflection limits defined in para. 5.1.1.5 are applicable when the deflections measured reflect relative motion between points on the branch piping and can be associated with a deflected shape.

(c) The process piping drives the branch piping at a high acceleration level as a rigid body. This problem is generally associated with a cantilevered mass. The peak acceleration at the center of gravity of the branch piping must be measured to establish the inertial force acting at the center of gravity of the branch piping. The cantilever mass and center of gravity of the branch piping must be conservatively estimated and a resultant stress calculated. The resultant stress should be compared with the criteria listed in paras. 3.2.1.2(a) and 3.2.1.2(b).

Nonmandatory Appendix I provides guidance on completing this evaluation.

5.1.1.5 Deflection Limits. The vibrational deflection limit of a piping system depends on a large number of material and geometric considerations with many combinations of the variables. One method of dealing with this complexity is to subdivide the piping systems into characteristic spans that can be physically defined and modeled. A deflection measurement can then be conservatively checked against an allowable deflection limit calculated for that characteristic span. A breakdown of the characteristic spans for which allowable deflection limits have been computed is given in para. 5.1.1.6.

Deflection limits are given in terms of a characteristic span length, outside pipe diameter, and a configuration coefficient. The characteristic span length and the configuration coefficient are established by subdividing the piping system into a series of characteristic spans as described in para. 5.1.1.6.

The configuration coefficient (R) and the nominal vibration deflection (δ_n) values are based on an allowable stress of 10,000 psi with stress indices equal to unity. The allowable deflection limit δ_{allow} is shown in para. 5.1.1.5.1.

Where the user demonstrates analytically or by experience that the VMG 2 methods are inherently conservative by at least a factor of 1.3, α may be taken as 1.0. The allowable deflection limit is then compared to the measured value for piping vibration qualification.

5.1.1.5.1 Determination of Allowable Deflection Limit. Nominal vibration deflection value

$$\delta_n = K(L^2/D_o)/144$$

Allowable vibration deflection limit

$$\delta_{\mathrm{allow}} = (S_{\mathrm{el}} \times \delta_n)/(C_2K_2 \times \sigma_n \times \alpha)$$

where

D_o = the outside diameter of the piping, the units of D_o and L are the same (e.g., both in feet or both in meters)

K = the configuration coefficient determined based on a nominal stress (δ_n) of 10,000 psi (68.95 MPa)

L = the characteristic span of the vibrating piping segment

δ_{allow} = the allowable zero to peak vibration deflection limit based on the endurance limit (S_{el}/α) of the piping material and the applicable peak stress indices (C_2K_2)

δ_n = a nominal zero to peak vibration deflection value based on a nominal stress (σ_n) of 10,000 psi (68.95 MPa) and with no consideration of peak stress indices

Paragraph 3.2.1.2 defines S_{el}, α, C_2, and K_2.

5.1.1.6 Characteristic Span Models. It is recommended that the measured deflection data be examined to assist in determining the appropriate characteristic span used to obtain the allowable deflection limit.

Characteristic spans are broadly classified into two categories by the piping restraints. A single-end restraint with one end free forms the first category, and restraint of both ends of a characteristic span forms the second category. The categories are then subdivided into combinations of a single span and two spans joined by a 90 deg elbow. Deflections are measured in the plane of the elbow and out of the plane of the elbow as shown in Fig. 2. The rotational constraint at restraint points is assumed to be fixed for a conservative computation of the allowable deflection limit. An outline of the basic characteristic spans is given below. For any configuration not covered below, a conservative K factor may be established by the user, provided equivalent conservatism is maintained.

(a) Single-end restraint, cantilever

(1) cantilever single span (Fig. 4)

(2) cantilever span, elbow, span

(a) deflection in plane of elbow, end span free (Fig. 5)

(b) deflection in plane of elbow, guided end span (Fig. 6)

(b) Restraint at both ends

(1) single span

(a) single span (Fig. 3)

(b) single span with elbow restraint [special case of para. 5.1.1.6(b)(1)(a) or limit case of para. 5.1.1.6(b)(2)(a)]

(2) span, elbow, span

(a) maximum deflection measured out of plane of elbow between restraint point and elbow of long span; ratio of short span to long span is less than 0.5 (Fig. 7 with configuration coefficient K from Fig. 9)

(b) maximum deflection measured out of plane of elbow at intersection of long span and elbow; ratio of short span to long span is between 0.5 and 1.0 (Fig. 8 with configuration coefficient K from Fig. 9)

5.1.2 Velocity Method

5.1.2.1 General Requirements. The method requires consecutive measurements of velocity at various points on the piping system to locate the point that is exhibiting the maximum vibratory velocity. Once this point is located, a final measurement of the maximum velocity (V_{max}) at that point is made and compared with an allowable peak velocity (V_{allow}) as given in para. 5.1.2.4. The criterion for acceptability is

$$V_{max} \leq V_{allow}$$

5.1.2.2 Instrumentation. The instrument used should be portable and capable of making a number of consecutive velocity measurements at various points on the piping. The instrument should be capable of indicating a trace of the actual velocity-time signal from which the maximum velocity can be read. This may be achieved by readout devices such as a cathode-ray tube or a paper chart recorder. Alternatively, the instrument could have a holding circuit that would result in a meter reading of the maximum velocity.

5.1.2.3 Procedure. Initial measurements are to be taken at points on the piping that appear to be undergoing the largest displacements. These will normally correspond to points of the highest velocity. At each such point, measurements can be taken around the circumference of the pipe to find the magnitude of the maximum velocity. Measurements may be confined to directions perpendicular to the axis of the pipe at that point.

The maximum velocity should be obtained only from the actual velocity-time signal. The readout of the signal should be of sufficient duration to ensure a high probability that the maximum velocity has in fact been obtained for that point in that direction.

5.1.2.4 Allowable Peak Velocity. The expression for allowable velocity is

$$V_{allow} = \frac{C_1 C_4}{C_3 C_5} \frac{\beta\,(S_{el})}{\alpha C_2 K_2}$$

where

V_{allow} = allowable velocity, in./sec (mm/s)

β = 3.64×10^{-3} to obtain V_{allow} in in./sec when S_{el} is in units of psi

β = 1.34 to obtain V_{allow} in mm/s when S_{el} is in units of MPa

S_{el}, C_2, K_2, and α are defined in para. 3.2.1.2. The secondary stress index C_2 and the local stress index K_2 are associated with the point of maximum stress and not necessarily with the point of maximum velocity.

This velocity criterion is consistent with the deflection criterion for a fixed end beam at resonance in the first mode.

C_1 = a correction factor to compensate for the effect of concentrated weights along the characteristic span of the pipe (see Fig. 10)

C_3 = a correction factor accounting for pipe contents and insulation

$$= \left(1.0 + \frac{W_F}{W} + \frac{W_{INS}}{W}\right)^{1/2}$$

where

C_4 = correction factor for end conditions different from fixed ends and for configurations different from straight spans
= 1.0 for a straight span fixed at both ends, but conservative for any practical end conditions for straight spans of pipe
= 1.33 for cantilever and simply supported pipe span
= 0.74 for equal leg Z-bend
= 0.83 for equal leg U-bend

C_5 = correction factor to account for off-resonance forced vibration, equal to the ratio of the first natural frequency of the piping span to the measured frequency for ratios between 1.0 and 2.0. For ratios greater than 2.0, the C_5 factor is herein undefined. For ratios less than 1.0, the C_5 correction factor equals 1.0.

W = weight of the pipe per unit length, lb/ft (kg/m)

W_F = weight of the pipe contents per unit length, lb/ft (or kg/m)

W_{INS} = the weight of the insulation per unit length, lb/ft (or kg/m)
= 1.0 for pipe without insulation and either empty or containing steam

Nonmandatory Appendix D presents examples of correction factors C_1 and C_4 for typical piping spans along with a combination of these factors to provide an initial screening method.

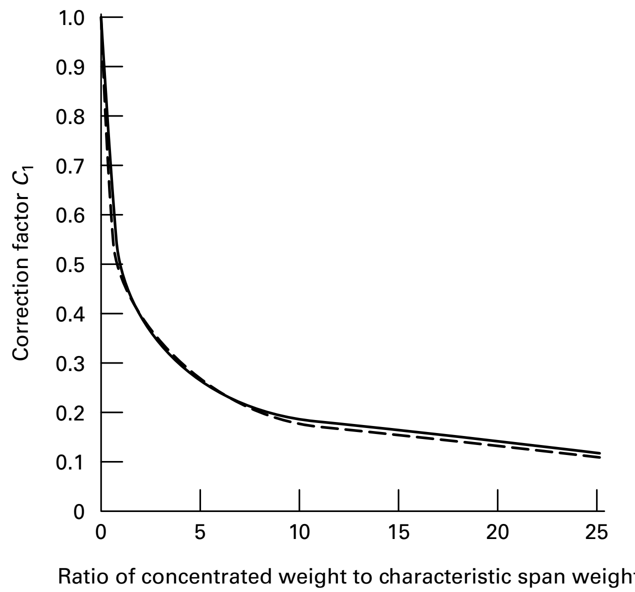
5.1.2.5 Precautions. The basic relationship between the allowable velocity and stress is developed from the assumption that the vibratory mode shape matches the mode shape at the first natural frequency. The user is cautioned against indiscriminate use of the velocity criteria without considering velocity, amplitude, frequency, and mode shape of the vibration. The C_5 correction factor modifies the basic relationship to account for off-resonant forced vibrations.

If the piping span is vibrating at frequencies below the first mode natural frequency, then it is inappropriate to use the velocity criteria without the C_5 correction factor since the stresses calculated will be nonconservative, by approximately the ratio of the span natural frequency to the measured forced response frequency, for frequency ratios between 1.0 and 2.0.

For example, if the span natural frequency was 20 Hz and was vibrating at 10 Hz, the stresses predicted from a velocity measurement would be nonconservative by a factor of two, without the C_5 correction factor.

For multispan systems, commonly encountered in power plant piping, caution must be exercised when evaluating stresses caused by resonant excitation from adjacent spans. A determination must be made of the individual span natural frequencies before the decision to use the velocity criteria method can be justified. If the ratio of the first natural frequency of the span to the measured frequency is less than or equal to 2.0, then the velocity method may be used. Values for this ratio greater than 2.0 have not been addressed by this Part.

Fig. 10 Correction Factor C_1



5.2 Transient Vibration

Another method for the evaluation of vibration of the piping systems is for those subjected to transient loads for which the expected response under the anticipated transient loads is determined by analysis. Piping systems that are not suitable or adaptable to these methods shall be evaluated by the methods of para. 6.

5.2.1 General Requirements. This method requires that a dynamic analysis of the piping system subjected to the expected transient loads has been performed yielding the system dynamic responses. Furthermore, the analytical responses must be shown to be conservative through comparison of the analytical responses with those measured during testing. The simplified method requires that dynamic response of piping, at selected locations, be measured. A minimum of two separate remote locations selected for the data points should be based on the analysis performed. In addition, fluid pressure may be measured. The necessary parameters to be measured and their locations shall be included in the test specification.

The criteria for acceptability of the measured data are given in para. 5.2.3. If the criteria specified in para. 5.2.3 are not met, additional evaluation of the piping systems based on the measured data shall be made to justify the acceptance. This may include reanalysis of the piping system based on measured data.

5.2.2 Instrumentation. Appropriate instruments as recommended in para. 7 shall be used for obtaining the piping system responses.

5.2.3 Measurements and Criteria for Acceptance. The measured responses shall be compared to the analytically obtained response of the system. If the analysis indicates larger responses than those measured and the general requirements of para. 3 concerning analysis versus test conditions have been met, then the vibratory response of the system is acceptable.

5.3 Inaccessible Piping (for Both Steady-State and Transient Vibration Evaluation)

For inaccessible piping systems requiring monitoring, the search procedure for maximum response location is not required. The locations of anticipated maximum response at which measurement devices are to be applied shall be defined. Adequate precautions shall be taken to verify that the assumptions used for the selection of anticipated maximum response locations are consistent with the installed system response.

6 RIGOROUS VERIFICATION METHOD FOR STEADY-STATE AND TRANSIENT VIBRATION

Another method is required when the portion of the system is evaluated in VMG 1 or when the methods of paras. 4 and 5 are not applicable or are overly conservative. This method is also intended for application to systems where the dynamic characteristics indicate that the system modes are primarily a result of rocking of massive equipment (such as pumps and heat exchangers). The primary objective of this verification is to obtain an accurate assessment of the vibrational stresses in the piping system from the measured vibrational behavior.

Two acceptable techniques for implementing this method are given in paras. 6.1 and 6.2 along with corresponding requirements. Paragraph 6.1 is supplemented by Nonmandatory Appendices B and C, which describe several methods of implementing this technique. Other techniques may be used provided that they are demonstrated to be conservative.

6.1 Modal Response Technique

6.1.1 General Requirements. This method requires that the modal displacements and natural frequencies of the system be identified from the test data.

The method also requires that a modal analysis of the system be performed yielding analytically determined natural frequencies and mode shapes and modal stress vectors (or bending moments) corresponding to the mode shape vectors. The analysis and test natural frequencies and mode shapes of the piping system shall be correlated and the analytical stress vectors shall then be used to determine the actual state of stress in the piping due to the measured modal displacements.

6.1.2 Test Requirements. The piping system shall be instrumented sufficiently to enable identification of the natural frequencies and modal displacements. It is not necessary to ensure that the measurements are taken at the location of maximum vibration. The instrumentation may be capable of measuring acceleration, displacement, or velocity according to the guidelines of para. 7. Locations of instruments shall correspond closely to points included in the analytical model of the system.

The system shall be exercised through the conditions defined in test specifications. A sufficient amount of data shall be recorded to allow appropriate data processing as described in para. 6.1.3.

6.1.3 Data Processing. Steady-state vibration data shall be reduced to obtain the zero-to-peak displacement in each of the predominant vibrational modes of the system. Methods of determining the modal displacements are available, and two of these are discussed in Nonmandatory Appendix B. When using either of the two methods described in Nonmandatory Appendix B, special attention should be given to separately identify closely spaced modes that may exist in the system.

6.1.4 Test and Analysis Correlation. The measured modal frequencies and modal displacements of the piping system shall be correlated to analytically obtained modal frequencies and mode shapes for all major contributing modes. As a minimum, the test and analytical mode shapes shall correlate with respect to the predominant modal direction; the relative magnitudes of the modal components need not be in exact agreement. In addition, the corresponding modal frequencies of the test and analysis shall be in reasonable agreement.

6.1.5 Evaluation of the Measured Responses. The measured modal displacements of the piping and the correlated analytical results shall be used to obtain an accurate assessment of the vibrational stresses (or moments) in the piping system. A method for obtaining the vibrational stress in the piping using the measured piping displacements and the information from the modal analysis of the system is given in Nonmandatory Appendix C. The resulting vibrational stresses shall be evaluated according to the acceptance criteria of para. 3.2.1.2.

6.2 Measured Stress Technique

Strain gages can be used to directly determine stresses in the piping system during steady-state or transient vibration. This Section outlines the general requirements in the use of strain gages. Several precautions associated with the use of strain gages are presented in Nonmandatory Appendix A. These precautions should be considered prior to defining the test program.

6.2.1 General Requirements. The piping system shall be instrumented on straight pipe with a sufficient number of gages near points where maximum stresses in the piping system are expected to occur. Strain gages shall be located remote from points of stress concentration, when used for determining nominal bending moment.

6.2.2 Evaluation of the Measured Responses. The experimentally obtained strains at the instrumented points in the piping system shall be converted to a three-component moment set and evaluated using the acceptance criteria of para. 3.2.1.2.

7 INSTRUMENTATION AND VIBRATION MEASUREMENT REQUIREMENTS

Recognizing the ongoing advancement of data acquisition techniques, the guidelines presented here for the specification of the instrumentation and recording equipment, necessary to meet the minimum monitoring requirements associated with VMG 1, VMG 2, and VMG 3, are not intended to propose methods or techniques. Rather, they set forth the criteria necessary to ensure that the data taken by any method is accurate and repeatable and within the equipment capabilities. Nonmandatory Appendix A contains guidelines and precautions for typical vibration monitoring systems and can be used as a basis for the specification of the system to be used during testing.

Figure 1 shows typical components of a vibration monitoring system.

7.1 General Requirements

The system and techniques used for the vibration monitoring of all piping systems covered by this Part shall meet the minimum requirements described below.

7.1.1 System Specification

(a) A vibration monitoring system (VMS) specification shall be written and included in or referenced by the test specification. The VMS specification shall include the following:

(1) functional description

(2) list of equipment (manufacturer, model number, serial number)

(3) equipment calibration records

(4) equipment specifications

(5) installation specifications

(b) For the VMS, as well as for each device comprising the VMS, the following information and minimum requirements shall be contained in the equipment specification, when applicable:

(1) inputs and outputs: units and full-scale range of each

(2) accuracy: specified as a percentage of full-scale physical units

(a) VMS minimum requirement: greater than 10% of applicable value of acceptance criteria for the measured variable

(3) minimum measurable value

(a) VMS minimum requirement: less than 80% of applicable value of acceptance criteria for the measured variable

(4) range: full-scale capability with accuracy specification

(a) VMS minimum requirement: 20% greater than the applicable value of the acceptance criteria for the measured variable

(5) frequency response: minimum and maximum frequencies within specified accuracy

(a) VMS minimum requirement: frequency response range shall extend one-half octave above and below the maximum and minimum significant frequency range of the measured variable

(6) calibration data: specific requirements in para. 7.1.2

(7) other specifications: any other specifications unique to the measurement system or important for the accurate measurement of the variable (e.g., temperature compensation and mounting requirements)

Manufacturer's specifications are acceptable for each device comprising the VMS; however, care should be exercised to ensure that the application, mounting, and interfacing conditions do not affect or invalidate the manufacturer's specifications. This is especially important in transducer mounting and electrical loadings.

An example of the specification is given in Table 2.

7.1.2 Calibration. All equipment used as part of the VMS shall have current calibration documents. These shall be attached to or made part of the system specification. On-site checkout of the VMS shall be performed and documented to verify that the as-installed VMS is functioning according to the system specification.

7.1.3 Repeatability. Capability of the VMS to provide consistent results shall be demonstrated. This can be achieved by taking several consecutive measurements of a stationary variable during pretest setup and checkout. The results of these consecutive measurements should be within minimum accuracy requirements of the VMS specification.

7.1.4 Peak Versus rms Measurement. The acceptance criteria in this Part are based on zero-to-peak piping deflections; therefore, the VMS used must result in actual zero-to-peak measurements. If the instrumentation used yields rms measurements, then conservative methods must be used to convert the rms measurements to zero-to-peak values.

Table 2 Examples of Specifications of VMS Minimum Requirements Measured Variable — Displacement

Acceptance Criteria, mils (mm)	Accuracy, mils (mm)	Minimum Measurable Value, mils	Full-Scale Range, mils (mm)	Frequency of Response, Hz	Other: Max. Piping Temperature, °F (°C)
10 (0.254)	± 1 (0.0254)	< 8	12 (0.30)	0.5–60	250 (121)
100 (2.54)	± 10 (0.254)	< 80	120 (3.0)	0.5–20	300 (149)

8 CORRECTIVE ACTION

Corrective action is required to reduce piping vibrational stresses to acceptable values when piping steady-state or transient vibration exceeds the acceptance criteria of para. 3.2. Possible corrective actions include: identification and reduction or elimination of the excitation mechanism or vibration source; structural modifications to detune resonant piping spans; and changes in operating procedures to eliminate troublesome operating conditions.

If corrective restraints, circumferential stiffeners, for example, or system modifications are required to make the piping system acceptable, then the piping system stress analysis shall be reviewed and, as necessary, reconciled.

After corrective action is completed, postmodification testing shall be performed to determine if the vibrations have been sufficiently reduced to satisfy the acceptance criteria. Testing may involve determining the vibration response of the system during specific operating modes to verify adequacy of modifications implemented to control vibration.

Vibration excitation mechanisms and piping responses along with possible additional testing, analysis, and corrective actions are discussed in Nonmandatory Appendix E.

PART 3
NONMANDATORY APPENDIX A
Instrumentation and Measurement Guidelines

The purpose of this Appendix is to provide guidelines for the selection of devices and components of a vibration monitoring system (VMS). Recognizing that the instrumentation comprising the VMS will depend on the method chosen for the measurement program (VMG 1, 2, or 3), this Appendix provides suggestions, examples, and precautions for the instrumentation and techniques that might be employed for each method.

It is not the intent of this Appendix to be used in place of state-of-the-art techniques for vibration monitoring.

A-1 VISUAL METHODS (VMG 3)

The visual inspection method allows the use of senses, such as touch, to determine acceptability. For example, with sufficient experience vibration amplitude can be perceived fairly accurately for frequencies from 2 Hz to 30 Hz by feeling the pipe vibrate. Estimates of the amplitudes of the lower frequency vibrations can be obtained with a scale.

Simple aids, such as those suggested in Part 3, para. 4.2, can be used for estimating the amplitude of displacement for piping classified under VMG 3 when precise results are not required. Even so, the user should be cautioned against attempting to use these simple aids under circumstances where erroneous estimates could be obtained. For example, low amplitude [< 30 mils (< 0.76 mm)] vibrations at relatively high frequencies (> 20 Hz) would be difficult to quantify with a spring hanger scale. Likewise, low frequency (< 5 Hz) vibrations are usually difficult to read with an optical wedge because the eye's persistence of vision is inadequate to perceive a distinct intersection between the dark and light regions of the wedge.

It is the intent of the visual methods to identify those vibrations that are obviously acceptable. If doubt exists as to acceptability after the visual inspection methods are employed, then the methods of para. A-2 of this Appendix should be employed.

A-2 ELECTRONIC MEASUREMENT METHODS (VMG 2 AND VMG 1)

The following discussions regarding hardware selection and methodology are applicable to both VMG 1 and VMG 2 monitoring requirements.

A-2.1 Transducers

A-2.1.1 Accelerometers. One transducer for vibration measurement is the piezoelectric accelerometer. The advantages of the accelerometer include a capability for high-temperature operation, physical durability and reliability, ease and stability of calibration, intrinsic low noise, linearity over a wide dynamic range, small mass, and ease of application for absolute measurement.

A servo accelerometer that has excellent low-frequency response characteristics can also be used. Its advantages are a high output signal and frequency response down to direct current (dc).

Some accelerometer characteristics are of particular importance for piping measurements.

(a) *Variation of Sensor Output With Temperature.* If the change in output from room temperature to operating temperature exceeds 10%, a correction factor determined from the Manufacturer's Data Sheet should be applied.

(b) *Variation of Sensor Output With Frequency.* This variation depends on the type of accelerometer, the mounting technique used, and whether its output signal is fed into a charge-sensitive amplifier or a voltage-sensitive amplifier. Variation of output may be as high as 3% per decade in frequency. If the variation exceeds 10% over the frequency band being measured, data should be corrected in accordance with the Manufacturer's Data Sheet.

(c) *Maximum Temperature of Operation.* Under no circumstances should the maximum operating temperature specified by the Manufacturer be exceeded. However, direct attachment to the pipe surface is usually feasible because accelerometers with maximum temperature ratings of at least 650°F (345°C) are readily available. Thermally insulated mounts may also be used, if necessary, to reduce the temperature at the accelerometer.

The accelerometer characteristics, such as frequency response and associated electronic circuitry, should be compatible with the required measurement goals. Proper scaling and band-pass filtering should be employed to aid the analyst in obtaining vibration data within the requirements of Part 3, para. 7.

Two intrinsic shortcomings of acceleration measurements that may cause difficulties in plant piping applications are low-level, high-impedance output and poor signal-to-noise (S/N) ratio at low frequencies, particularly following the double integration required to obtain displacement.

Should these shortcomings prohibit the use of accelerometers, the user may be able to achieve better performance with the high-output, low-impedance devices described below.

A-2.1.2 Velocity Transducers. Velocimeters (or velocity pickups) are transducers designed to respond directly to velocity. They usually consist of a moving coil or moving magnet arranged so that the electrical output generated is proportional to the rate at which the magnetic field lines are cut by the moving element, and hence its velocity. The main advantage of these electrodynamic transducers over accelerometers is their high-level, low-impedance output, thereby making their signals relatively immune to electromagnetic noise pickup. Their chief disadvantages are their larger size and their somewhat restricted useful linear band width. Contamination from background at low frequencies limits their usefulness in providing displacement indications, since the necessary integration tends to amplify low-frequency noise selectively.

A-2.1.3 Displacement Transducers. Examples of direct-sensing displacement transducers applicable to piping vibration measurements are the eddy current probe (or proximity probe), the linearly variable differential transformer (LVDT), hand-held vibrometer, and the lanyard gage potentiometer. All sense absolute displacement relative to a fixed reference and, therefore, have frequency response and S/N curves that are uniform all the way to zero frequency (dc). This is their chief advantage, along with high electrical output and, hence, immunity to extraneous noise. An attendant disadvantage, however, is that they must be mounted firmly to some structure that is stationary relative to the vibrating system whose displacement is to be measured. This is often difficult to accomplish in an operating plant environment. Other disadvantages of these transducers are the following:

(a) some have a lower high-frequency response

(b) limited range of displacement over which the transducer responds linearly and without hysteresis

(c) need for special accompanying electronics (oscillator/demodulator) and cabling

(d) in some cases, high noise, offset errors, and limited (quantized) displacement resolution

A-2.1.4 Special Transducers. Other instrumentation (e.g., LASER vibrometers that detect the Doppler shift accompanying motion of the target) is commercially available for those special situations requiring unusually high measurement accuracy or where physical access to the vibrating structure prohibits use of the transducers already described. Such devices are too specialized to warrant further description in this document.

A-2.1.5 Strain Gages. The use of strain gages (μin./in.) at selected points in the piping system provides data that can be used for comparison to acceptance criteria. The type of gages normally used on the piping systems are either the weldable or the bondable types. The temperatures and radiation level typical of power plant environments may limit the use of bondable gages. Weldable gages that will operate for all temperature and radiation levels typical of nuclear power plant environments are available. The usual requirement is that the state of stress at points on the piping system can be determined from strain gage readings. This implies the use of an appropriate theory relating strains to stresses. The validity of the final results depends on the validity of any relationships used in reducing the data.

The user of strain gages must be aware of some problems encountered by the use of these devices, especially for the measurement of static strains. These problems are associated with temperature compensation, bond stability, instrument stability and moisture, radiation, and high-temperature environments. The user should employ state-of-the-art techniques to circumvent these potential problems.

A-2.2 Cables

Since cable noise can distort the vibration signals from sensors, low-noise cable should be used between the sensor and the signal conditioner. The cable should have temperature characteristics adequate for the expected environment.

If cable connectors are used, precautions should be taken to avoid the introduction of moisture at these locations, since, in general, long cable runs [> 100 ft (> 30.48 m)] between the transducer and the signal conditioning unit may produce high-noise pickup or signal attenuation. A remote preamplifier (or remote charge converter) may be required to avoid these difficulties. The transducer and cable Manufacturer's Data Sheets should be consulted for details.

A-2.3 Signal Conditioner

A-2.3.1 General Requirements. The signal conditioner should have proper electronic characteristics for the selected transducer.

For accelerometer signal conditioning, integrating circuits yielding velocity and displacement outputs from the acceleration signal may be included in the signal conditioner. Gain normalization for direct incorporation of accelerometer output scale factor (as supplied by the Manufacturer) is an important feature because all outputs can then be designed to read out directly in absolute velocity and displacement units.

A-2.3.2 Frequency Range. A working range from 0 Hz to 300 Hz will cover practically all piping applications.

A-2.3.3 Vibration Scale Range. The signal conditioner should typically be able to measure velocities from 10^{-2} in./sec to 10^{2} in./sec (0.254 mm/s to 25.40 mm/s) and displacements from 10^{-4} in. to 10 in. (0.00254 mm to 254 mm).

To provide accurate measurements over the wide amplitude ranges specified above, the signal conditioner should provide several fixed-gain adjustments or intermediate full-scale ranges.

A-2.3.4 Filtering. Switch-selected, low-frequency cutoff limits should be provided to eliminate extremely low-frequency signals and unwanted noise.

Low-pass filtering should be available at the upper end of the vibration band to eliminate unwanted high-frequency noise.

Band-pass filtering may often be desirable to reduce interference among sinusoidal amplitude distributions, or pulselike with high-crest factors, and sometimes mixtures of all three. Therefore, the proper amplitude function (rms, peak, peak-to-peak) should be carefully selected, and should be consistent with the acceptance criteria for the measured variable.

A-2.4 Auxiliary Equipment

An oscilloscope for viewing the waveforms of the acceleration, velocity, and displacement outputs from the signal conditioner is desirable in most cases. A real-time frequency analyzer and an analog FM tape recorder (for data preservation and/or additional offline study and processing) are also useful, optional equipment. A strip chart recorder or oscillograph can also be used to provide a permanent record of the analog meter indication.

PART 3
NONMANDATORY APPENDIX B
Analysis Methods

This Appendix describes two methods of obtaining modal displacements of the piping system from the measured total displacement time history. It is recommended to be used in conjunction with Part 3, para. 6.1.

B-1 FOURIER TRANSFORM METHOD[1]

The recorded acceleration, velocity, or displacement time histories can be converted to a spectral density function using Fast Fourier Transform techniques. The spectral density should be computed in the frequency range that contains the expected predominant system response. A sufficient number of spectral averages should be made to ensure that the density function has converged. Integration of the density function over discrete frequency bands around the predominant modal responses yields the rms modal response. These can readily be converted to peak-to-peak response through consideration of the statistical properties of the response.

In addition to the modal responses, the spectral density function will indicate the system response at deterministic frequencies associated with shaft and blade passing frequencies of rotating equipment that excite the piping system.

The piping displacements at these frequencies should be determined. The piping displacements at these frequencies should be absolutely summed with the modal displacement of the piping system mode that is nearest to the deterministic frequency or that closely resembles the displaced configuration at the deterministic frequency.

B-2 OTHER METHODS

Alternative methods may be employed, such as modal superposition, provided that the method used is demonstratively conservative and the test analysis correlation requirements of Part 3, para. 6.1.4 are met.

[1] The user of this method is referred to the latest revision of ANSI S210, Methods for Analysis and Presentation of Shock and Vibration Data.

PART 3
NONMANDATORY APPENDIX C
Test/Analysis Correlation Methods

This Appendix presents a method for converting measured modal displacements of the piping system to bending stress (or bending moments) through the use of analytically obtained modal characteristics.[1] It is recommended to be used in conjunction with Part 3, para. 6.1.

C-1 TEST/ANALYSIS CORRELATION

The modal displacements at each measurement point, obtained in Part 3, para. 6.1.3, should be tabulated and normalized to an appropriate value (such as the maximum displacement) in that mode. The relative sign of each displacement can be obtained by computing the phase between measurement points using Fourier Transform techniques. This yields a normalized mode shape and modal frequency obtained by test that can be compared to analytically obtained normalized mode shapes and frequencies. The test and analytical results should be correlated according to the requirements of Part 3, para. 6.1.4.

C-2 EVALUATION OF THE MEASURED RESPONSES

Having achieved a correlation of test/analysis results, the analytically obtained modal moments or stresses in the system piping can be determined using the actual modal responses obtained from the test data. This can be done in the following way.

The measured modal displacement at point j in mode i (denoted by $D_{ij}{}^{T}$) is divided by the corresponding analytical displacement ($D_{ij}{}^{A}$), yielding the modal response factor K_{ij}, as shown below.

$$K_{ij} = \frac{D_{ij}{}^{T}}{D_{ij}{}^{A}}$$

Theoretically, all K_{ij} within a mode should be the same if perfect correlation of test and analytical mode shapes has been achieved. Realistically, however, the K_{ij} will vary. Therefore, for each mode the maximum K_{ij} is chosen as the modal response factor for mode i (denote as K_i). The maximum K_{ij} should be chosen from among those K_{ij} in the direction of predominant modal motion to reduce unnecessary conservatism. Having obtained the modal response factors (K_i) for each mode, the test stress vector ($S_j{}^{T}$) for each mode should be calculated by premultiplying the analytical stress vector[1] $(S_j{}^{A})_i$ by the modal response factor:

$$(S_j{}^{T})_i = K_i(S_j{}^{A})_i$$

The modal stress vectors thus obtained should be combined by an appropriate conservative method to obtain the total stress in the piping.

[1] It is assumed in this method that the stress vector includes the stress indices as defined in Part 3, para. 3.2.1.2. Alternatively, the modal bending moments in the piping (obtained from the modal analysis of the piping) can be converted to stress using the equation for S_{alt} defined in Part 3, para. 3.2.1.2.

PART 3
NONMANDATORY APPENDIX D
Velocity Criterion

This Appendix describes a method for establishing a velocity criterion for screening piping systems. Using these procedures, piping systems requiring further analysis can be determined. This Appendix is to be used in conjunction with Part 3, para. 5.1.2.4.

D-1 VELOCITY CRITERION

The expression for allowable peak velocity from Part 3, para. 5.1.2.4 is

$$V_{\mathrm{allow}} = \frac{C_1 C_4}{C_3 C_5} \frac{\beta(S_{\mathrm{el}})}{\alpha C_2 K_2}$$

where

C_1 = correction factor that compensates for the effect of concentrated weights. If concentrated weight is less than 17 times the weight of the span for straight beams, L-bends, U-bends, and Z-bends, a conservative value of 0.15 can be used for screening purposes.

C_2K_2 = stress indices as defined in the ASME Code; $C_2K_2 \leq 4$ for most piping systems

C_3 = correction factor accounting for pipe contents and insulation; for contents and insulation equal to the weight of the pipe, the value would be 1.414; in most cases it is less than 1.5

C_4 = correction factor for end conditions different from fixed ends and for configurations different from straight spans
= 1.33 for cantilever and simply supported beam
= 0.74 for equal leg Z-bend
= 0.83 for equal leg U-bend
= 0.7 as conservative value for screening purposes

C_5 = correction factor that is used when measured frequency differs from the first natural frequency of the piping span; for frequency ratios less than 1.0, the value is 1.0

S_{el}, α = see Part 3, para. 3.2.1.2

β = see Part 3, para. 5.1.2.4

D-2 SCREENING VELOCITY CRITERION

If conservative values of the correction factors are combined, a criterion can be derived that should indicate safe levels of vibration for any type of piping configuration. Using this criterion, piping systems can be checked and those with vibration velocity levels lower than the screening value would require no further analysis. Piping systems that have vibration velocity levels higher than the screening value do not necessarily have excessive stresses, but further analysis is necessary to establish their acceptability.

The following correction factors are considered to be conservative values and should be applicable to most piping configurations; however, the conservatism for extremely complex piping configurations cannot be attested.

C_1 = 0.15
C_2K_2 = 4
C_3 = 1.5
C_4 = 0.7
C_5 = 1.0
S_{el}/α = 7,690 psi (53 MPa)

$$V_{\mathrm{allow}} = \frac{(0.15)(0.7)(0.00364)(7{,}690)}{(1.5)(1.0)(4)}$$

= 0.5 in./sec (12.7 mm/s) — screening vibration velocity value

D-3 USE OF SCREENING VIBRATION VELOCITY VALUE

A screening vibration velocity value of 0.5 in./sec (12.7 mm/s) has been established that can be used in conjunction with Part 3, para. 5.1.2.4. Piping systems with peak velocities less than 0.5 in./sec (12.7 mm/s) are considered to be safe from a vibratory stress standpoint and require no further analysis. If vibrational velocities greater than 0.5 in./sec (12.7 mm/s) are measured, then further analyses are required to determine acceptability.

The first step to take if vibration velocities are greater than 0.5 in./sec (12.7 mm/s) is to determine more accurate values of the correction factors C_1, C_3, C_4, C_5, and the stress indices C_2K_2 so that the applicable velocity criteria for the piping system in question can be established.

PART 3
NONMANDATORY APPENDIX E
Excitation Mechanisms, Responses, and Corrective Actions

E-1 EXCITATION MECHANISMS AND PIPING RESPONSES

Piping vibrational response can be in the form of beam or shell-wall vibration. Each of these responses affect piping differently, and therefore the corrective action required for each should address the specific type of vibration being experienced. Examples of commonly encountered excitation mechanisms and piping responses are given in paras. E-1.1 and E-1.2, respectively.

E-1.1 Excitation Mechanisms

Piping vibration excitation mechanisms are pressure pulsations in the fluid or gas being transported by the piping or vibrations mechanically transmitted by attached or adjacent equipment.

Examples of potential sources of low-frequency vibration are control valve oscillations, turbulence caused by high flow velocities, flashing, and cavitation. These sources can be reduced by valve control system modifications such as the addition of damping, routing or pipe size changes to reduce turbulence, and the use of breakdown orifices or anticavitation valve trim to reduce flashing or cavitation.

Examples of high-frequency vibration sources are pump- or compressor-induced pressure pulsations produced by a control valve in a gas or steam system and vortex shedding at flow orifices in a water system. Modifications such as using a muffler, pulsation dampener or suction stabilizer, noise reduction valve trim, or adding multistage orifices are examples of how the vibration source can be reduced.

Pressure disturbances or pulsations are transmitted through the fluid the same way that sound is transmitted through air. Pressure pulsations can be amplified if the pulsation frequency is at or near a piping acoustical frequency; this resonant condition increases the potential for detrimental piping vibration. Acoustic frequencies are a function of the speed of sound in the fluid or gas and are inversely proportional to the piping length.

A common excitation mechanism is vortex shedding at flow discontinuities. Vortex shedding causes pressure pulsations at the distinct frequency ranges. If the shedding frequency is close to a piping acoustical natural frequency, then resonance can occur and the pulsations would be amplified. Modifying the discontinuity, e.g., flow orifice of side branch opening, can reduce the vortex shedding and shift the shedding frequency, thereby avoiding resonance. If this cannot be done, then modifications can be made to change the acoustic frequencies of the piping. Acoustic modifications include changes in pipe lengths to raise or lower its acoustical natural frequency, and the addition of a muffler, pulsation dampener, or suction stabilizer.

E-1.1.1 Cavitation. Cavitation is often the cause of piping vibration and also produces noise, pressure, fluctuations, erosion damage, and loss of flow capacity. How it occurs, its progression, and the involvement of piping components are described below. A case history is also provided that demonstrates how detrimental cavitation can occur at off-normal operating conditions.

E-1.1.1.1 Commentary. Vapor cavities are formed when liquid pressure falls below its vapor pressure, which can occur at pressure-reducing orifices and flow control valves. Cavitation occurs when a vapor cavity collapses as it is subjected to pressure greater than its vapor pressure. This can occur when a vapor cavity moves downstream of the orifice or valve. Collapse of the cavities produces pulsations, which can cause pipe vibration, surface erosion, and accelerated corrosion.[1,2]

Cavitation sounds different depending on its severity. It can vary from a cracking sound to a sound resembling gravel being transported through a pipe. At severe levels it can be damaging to hearing.

When the vapor cavities collapse next to a pipe or component surface, erosion and corrosion can occur. Cavitation erodes the protective oxidized surface, which allows corrosion to accelerate. Recent pipe failures and leakages have led to research to monitor and remedy the offending conditions.[3]

Components in piping systems, which contribute to the pressure decrease necessary to cause cavitation, are valves, orifices, nozzles, pumps, and elbows. Damage can be reduced by keeping the cavitation level low,

[1] Olson, D. E., "Piping Vibration Experience in Power Plants," Pressure Vessel and Piping Technology (1985), A Decade of Progress, Book No. H0030, The American Society of Mechanical Engineers (ASME).

[2] Wachel, J. C., et al, "Piping Vibration Analysis," Turbomachinery Symposium (September 1990).

[3] "Cavitation Erosion Model," Electric Power Research Institute Report, NATS RT-103193 (December 1993).

removing the boundary from the cavitation zone, treating the boundary surface to make it resistant to damage, dissipating the flow energy in stages, or ejecting air into the separation regions.[4] The most certain treatment for cavitation-produced pipe vibration is to reduce or eliminate the source.

E-1.1.1.2 Case History — Cavitation at Orifices. The chemical and volume control system (CVCS) in some pressurized water reactor plants contains a single stage stepdown orifice in the Letdown portion of the system. The orifice has a bore of 0.25 in. and a length of approximately 24 in. The pressure drop across this orifice is approximately 2,000 psig (from an upstream reactor coolant system pressure of 2,250 psig to a downstream pressure of about 250 psig). A back pressure of 200 psig or larger is required to prevent cavitation from occurring at the discharge end.

At one nuclear plant, the pressure at the discharge end dropped to approximately 100 psig when a pressure instrument drifted out of calibration. This condition was discovered after nine months of operating under this condition and the system was reconstituted to its design conditions. However, this extended period of operation outside the design differential pressure condition was sufficient to cause cavitation and subsequent erosion at the discharge end of the orifice. This erosion adversely affected the fluid characteristics at the discharge end causing continuous cavitation, which continued to worsen even under design pressure conditions.

The cavitation excited the piping system. The vibration levels were sufficient to cause leaks in the socket welded joints. The joints were repaired using similar design details, but they continued to fail at ever increasing rates as the orifice continued to erode due to the continuing cavitation.

A review of plant records revealed that the previous operation was outside the design back pressure requirement. An engineering evaluation indicated the potential for cavitation and possible erosion of the orifice. The cavitation and socket weld failures ceased after the orifice was replaced.

E-1.2 Piping Responses

Piping beam vibration is the most commonly encountered response. This vibration results from excitation of piping structural modes that cause piping to vibrate similar to simple beams. This type of vibration is typically most predominant below 20 Hz although beam vibration with frequencies up to 100 Hz or more is possible. Eliminating or reducing the vibration excitation source is the most effective corrective action. Low-frequency beam vibration can also be adequately restrained through the addition of supports.

[4] Tullis, J. P., "Hydraulics of Pipelines," John Wiley and Sons, New York (1989).

Experience has shown that the most effective use of restraints is obtained by supporting piping near bends and at all heavy masses and piping discontinuities. Vibrations of vents, drains, bypass, and instrument piping can be corrected by bracing the masses (valves, flanges, etc.) to the main pipe to eliminate relative vibrations.

Supports and structures used to restrain piping vibration must be capable of enduring the continuous vibration loadings that they are installed to restrain. This vibration can result in excessive wear and fatigue of components and supports not specifically designed for vibration. Therefore, items installed for this purpose must be able to withstand this vibration, or inspections and replacements of these items should be scheduled.

High-frequency piping vibration results in small displacement amplitudes, on the order of several mils or less, and is commonly prevalent throughout a large portion of a piping system. Therefore, the addition of supports is typically not an effective means of controlling high-frequency vibration. For example, the free play inherent in most supports would not restrain high-frequency vibration.

Piping shell-wall vibrations typically occur at high frequencies. For example, the lowest frequency shell mode of vibrations for a 24 in. Schedule 40 pipe is 190 Hz. Piping shell-wall vibration frequencies are proportional to the pipe-wall thickness and are inversely proportional to the pipe diameter. The most effective corrective action for shell-wall vibration is to eliminate the vibration excitation source. If the source cannot be adequately reduced, then the shell wall vibration frequency must be moved out of resonance, which could involve changing the pipe dimensions, such as using a heavier wall pipe. Circumferential stiffeners may also be used to increase the piping shell wall frequency. Constrained layer damping can be added to reduce the dynamic response and stress.

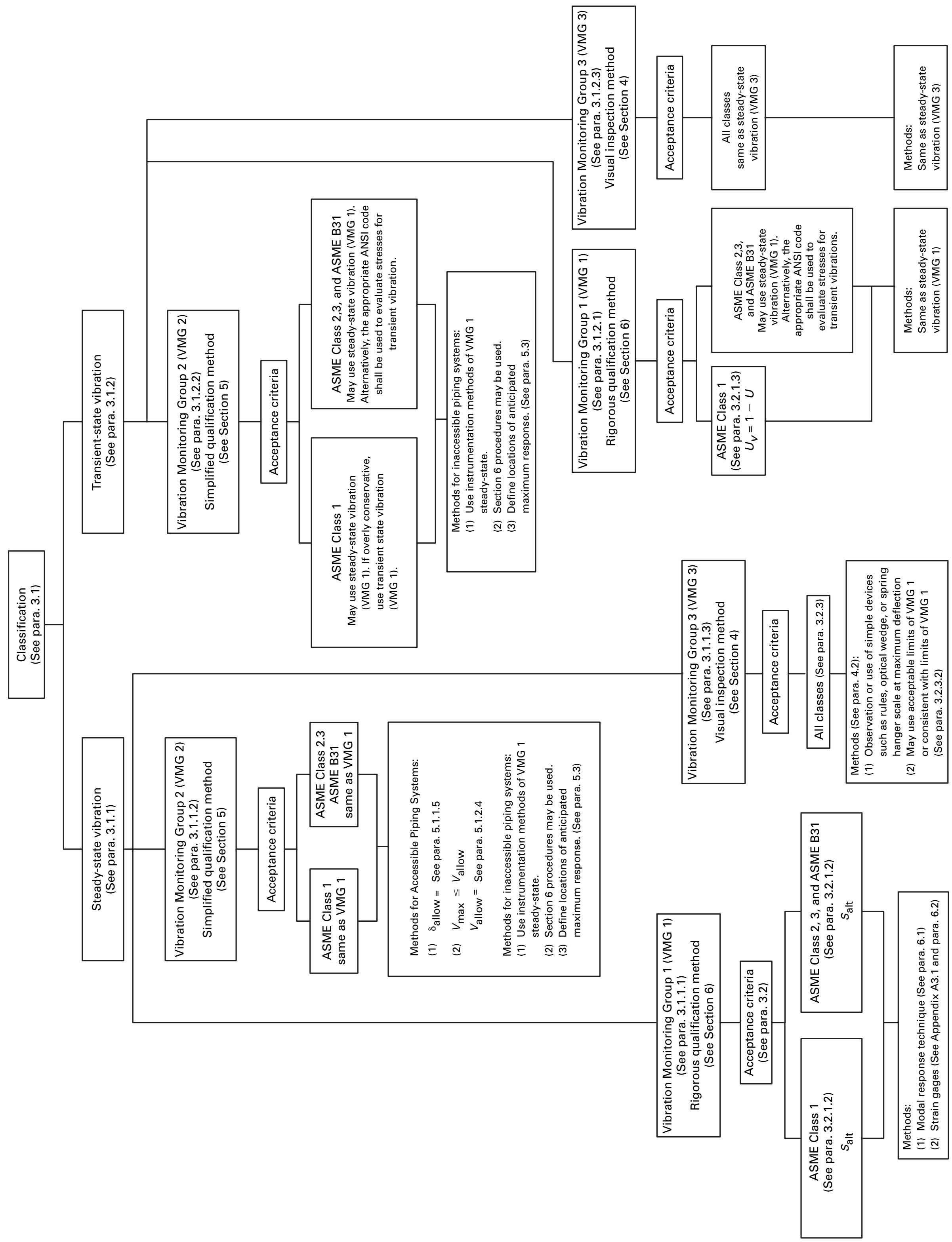
E-2 ADDITIONAL TESTING AND ANALYSIS

Root cause investigation may also involve more detailed analysis and/or testing. These steps can be taken to assist in determining the root cause of the vibration, or to reduce possible conservatism in the methods used to determine vibrational stresses. For example, vibration that exceeds the limits determined through the simplified evaluation techniques given in Part 3, para. 5 may be demonstrated to be within acceptable limits when more detailed techniques are used. The methods of Part 3, para. 5 were developed to be efficient methods of qualifying the majority of piping; however, conservative assumptions were made to simplify the criteria. Therefore, by either more detailed analysis and/or testing, higher vibrational displacements may be justified. More detailed analysis may, for example, include the methods described in Part 3, para. 6 or finite element modeling of a particular structure or component. Detailed testing can involve the application of strain gages to determine with a higher degree of accuracy the actual peak stress levels in the piping. Strain gage testing may also be used, possibly in conjunction with test and analysis correlation, to reduce conservatism. A continuous monitoring data acquisition system may also be temporarily used to determine system vibrational response during plant operation.

PART 3
NONMANDATORY APPENDIX F
Flow Chart — Outline of Vibration Qualification of Piping Systems

Figure F-1, Flow Chart — Outline of Vibration Qualification of Piping Systems, appears on the following page.

Fig. F-1 Flow Chart — Outline of Vibration Qualification of Piping Systems



PART 3
NONMANDATORY APPENDIX G
Qualitative Evaluations

For a piping system to be deemed acceptable, the observed piping vibration must also be acceptable based on qualitative evaluations made during the walkdown. This is in addition to demonstrating acceptability based on the quantitative measurements and calculations of VMG 1, 2, or 3. Qualitative evaluations are made without the aid of measurement data or made in addition to measured data. Qualitative evaluations of observed piping responses are made based on comparisons to known acceptable responses.

Qualitative evaluations are not acceptable if the observed conditions are judged to have a detrimental impact on the integrity of the piping system, i.e., the capability to maintain pressure integrity or perform its safety function. Conditions judged to affect only the maintenance of the system, but not its integrity, can be considered acceptable but should be flagged for future corrective action and/or monitoring. Caution must be used when touching high-temperature or high-energy piping.

Qualitative evaluations rely primarily on observations and judgments made during the piping walkdowns. Observations include the use of perceptual (visual, tactile, aural) inspections. This includes listening for abnormal noises, for example, due to excessive cavitation or component malfunction. In addition, the sense of touch can be used to determine the presence of high-frequency vibration, i.e., it may not be possible to visually perceive high-frequency vibrations, however, they are readily detectable through the sense of touch.

Items addressed by qualitative evaluations include

(a) applicable assumptions and limitations of the quantitative analysis techniques.

(b) potential detrimental effects of vibration on support wear and fatigue and pipe wall wear caused by rubbing at supports.

(c) the potential effect of vibration on threaded connections such as the loosening of nuts and bolts.

(d) component wear and corrosion, e.g., cavitation can result in significant wear and corrosion.

(e) vibration effects on equipment and components. Vibration can affect valve components such as attached hydraulic and instrumentation tubing and valve yokes. Vibration near a pump can be indicative of pump problems such as misalignment, cavitation, or imbalance.

(f) how limitations of the instrumentation affect the accuracy of the vibration measurements.

(g) signal noise. The contribution of undesirable electrical noise to the vibration signal.

(h) branch lines. Header vibration can adversely affect branch piping, and pressure pulsations transmitted to the branch piping can result in vibration throughout the branch piping.

PART 3
NONMANDATORY APPENDIX H
Guidance for Monitoring Piping Steady-State Vibration Per Vibration Monitoring Group 2

H-1 PURPOSE

The purpose of this Appendix is to provide guidance for monitoring and qualifying, using the displacement acceptance criteria, steady-state piping vibrations per the requirements of Vibration Monitoring Group 2, VMG 2, of Part 3. This guidance is based on extensive experience associated with field walkdowns and testing.

H-2 ASSUMPTIONS

These criteria assume that the stresses resulting from the steady-state vibration of an entire piping system can be conservatively estimated by dividing the system into smaller piping spans with various end conditions and using simple beam analogies to determine the deflection limits. It is further assumed that the vibration between node points and/or adjacent, parallel, seismically rigid restraints is dominated by a single mode of vibration that can be conservatively approximated by the fundamental mode of a simple beam model.

The allowable stress amplitudes, S_a, are in accordance with Part 3, para. 3. These stress amplitudes are based on 80% of the alternating stress intensity at 10^6 cycles divided by a stress reduction factor of 1.3 for carbon steels, and the minimum alternating stress intensity at 10^11 cycles for stainless steels. The values of alternating stress intensity are taken from Fig. I-9.1, I-9.2.1, or I-9.2.2 of the ASME BPV, Section III, Appendix I. Note that the assumptions stated in the ASME BPV Code for the use of these curves must be followed, including the following:

(a) The fatigue curves are not applicable at temperatures above 700°F for carbon steel and 800°F for stainless steel.

(b) The fatigue curves use a modulus of elasticity of 30×10^6 psi for carbon steel and 28.3×10^6 psi for stainless steel. Therefore, when an analysis is performed to determine vibration-induced stresses using a modulus of elasticity different than that used in the fatigue curves, the calculated stresses shall be adjusted as specified in ASME BPV Code, Section III, NB-3222.4.

H-3 IMPLEMENTATION

A sample steady-state vibration monitoring procedure is shown in Fig. H-1. The procedure begins with the least involved method of monitoring, and the monitoring methods and associated analyses become more extensive as the measured vibration exceeds the criteria of the various monitoring levels. The procedure requires further action for evaluating vibrations that exceed all levels of acceptance criteria. The procedure is discussed in paras. H-3.1 through H-3.2.4.

H-3.1 Quantitative Evaluations

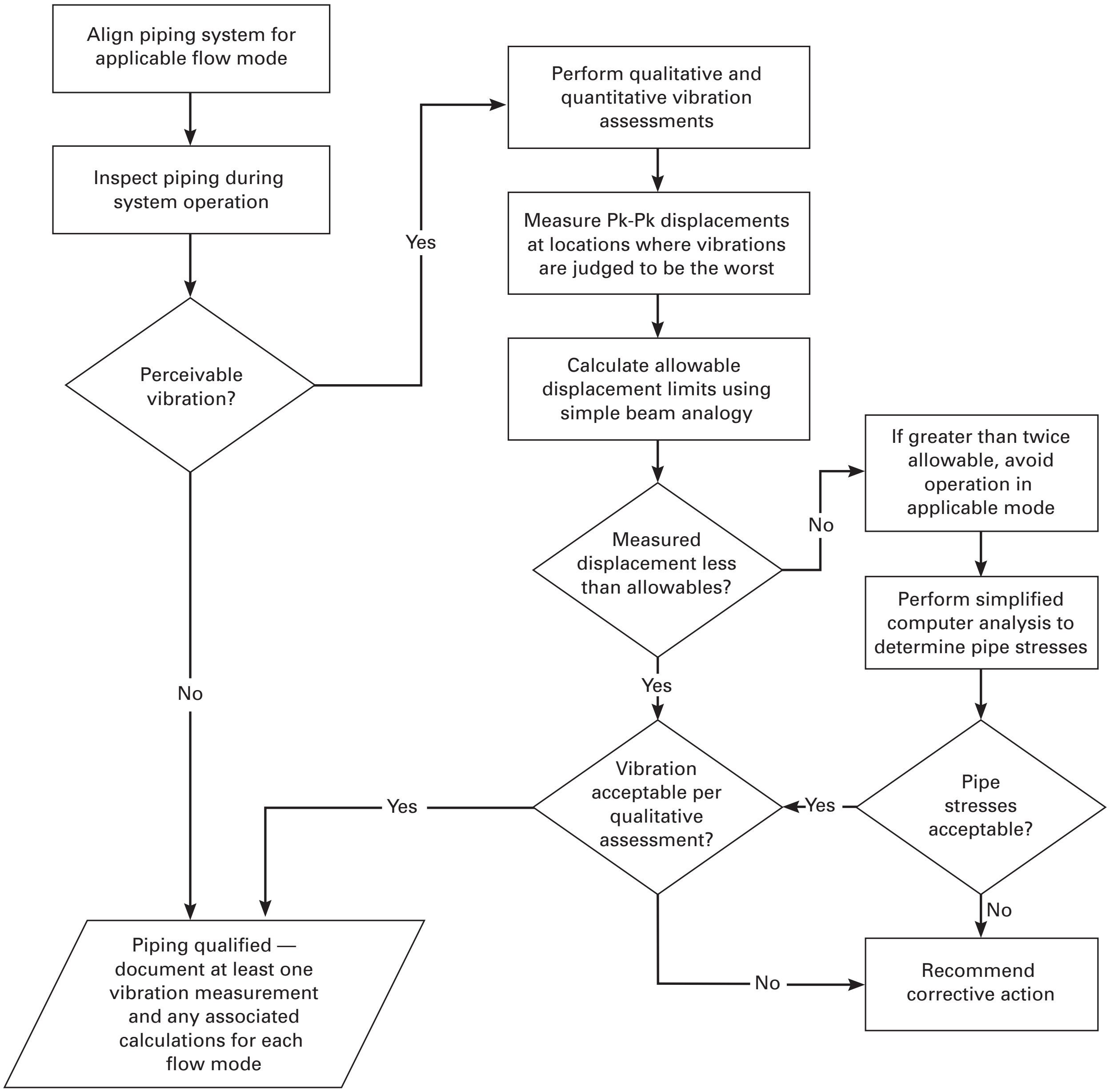
H-3.1.1 Determine Flow Modes to Be Monitored. The first step in implementing the monitoring procedure is to align the piping system in the flow mode(s) that have been judged, based on a review of all the possible operating modes of the system, to result in the most severe vibrations. If the most severe mode(s) cannot be determined from a review of the operating modes, the system should be tested in several or all its operating modes. Generally, the most severe steady-state vibrations occur during maximum or minimum flow conditions.

H-3.1.2 Inspect the Piping. Once the flow mode is established, the piping is inspected for perceivable vibration. Vibrations can be perceived not only by sight but also by touch and by hearing. Therefore, all senses should be alert when performing the walkdown, especially since lighting is usually not ideal and the piping may not be easily accessible.

H-3.1.3 Take Measurements. Even if the vibration appears to be minimal, at least one vibration measurement should be taken to document system response and provide a baseline for future reference. Equipment that measures true peak-to-peak displacement is recommended for measuring piping vibration, since the displacement is proportional to the pipe mode shape and, therefore, is proportional to the vibrational stress.

Equipment that measures root mean square (rms) displacement indicates only an averaged stress. The rms measurement cannot be readily converted to peak-to-peak measurements, except for pure sinusoidal signals. Since piping vibration is often quasirandom, equipment that measures rms signals should not be used. The predominant frequency of the vibration is also important and should be documented for baseline purposes and for aiding in problem resolution.

Fig. H-1 Monitoring and Qualification of Piping Steady-State Vibration



Normally, perceivable vibration exists at several locations on the piping system. Since it is usually not feasible, or necessary, to take vibration measurements at every location, measurements are taken at locations where the vibration is judged to be the worst on the basis of producing the highest vibrational stresses and/or on the basis of the qualitative evaluation.

The worst vibration does not always correspond to the location of the maximum displacement. For example, a displacement measured in a stiff portion of the piping system could be more severe than a large displacement measured in a more flexible portion of the system if the former results in a higher stress. Note that experience in monitoring piping vibration is required to accurately judge the locations of worst vibration and acquire a "feel" for the severity of vibration in general.

H-3.1.4 Evaluate Measurements. Once the locations of the worst vibrations are determined, the measured displacements are evaluated by applying the criteria presented in para. H-4. Documentation of the measurement should include the vibration location, magnitude, direction, and frequency, all the calculations performed, and the acceptability of the vibration.

The criteria in para. H-4 are simplified for easy application and, because of their simplicity, yield smaller allowable displacements than more detailed analyses would. Knowledge of piping structural dynamics and stress analysis is required to ensure the criteria are applied in a conservative manner.

H-3.1.5 Excess Vibration. If the measured displacement (VMG 2) exceeds the allowable displacement from para. H-4, further analysis is required to evaluate the vibration. When the allowable displacement is exceeded by more than a factor of 2, operation of the system in the offending mode flow should be avoided until further analyses or corrective action can be performed. Note that, based on experience, the simplified displacement allowables determined using the simple beam analogies of VMG 2, have typically been found to be conservative by at least a factor of 2, when compared to more detailed evaluations. This assumes the correct application of the criteria.

When the allowable displacement limit is exceeded, a simplified computer analysis can be performed. The purpose of this analysis is to reduce the conservatism inherent to the allowable displacement criteria by more accurately modeling the piping configuration and determining the piping deflected shape and pipe stresses.

The peak stresses from the simplified computer analysis are compared with the applicable allowable stress amplitude from Part 3, para. 3. If the allowable stress amplitude is exceeded, further action is recommended to resolve the vibration problem. Examples of recommended actions are shown in Table H-1. The most cost- and time-effective action is chosen for resolving the vibration problem.

H-3.2 Qualitative Evaluations

The objective of the qualitative evaluations is to address vibration causes and effects that are not quantified by the vibration measurements and evaluation techniques. For a piping system to be determined acceptable, the observed piping vibration must be acceptable based on a qualitative evaluation. This is in addition to demonstrating acceptability based on quantitative measurements and calculations.

Note that for the qualitative evaluation to be not acceptable, the observed conditions must be judged to have an immediate detrimental impact on the acceptability of the piping system. An example is severe cavitation that is judged to likely result in damage to the piping or components. Conditions that are judged not to have an immediate detrimental impact can be considered acceptable but should be flagged for future corrective action and/or monitoring. An example is vibration resulting from imbalance in a pump. This may not be an immediate concern, but should be flagged for future corrective action or maintenance.

Qualitative evaluations rely primarily on the observations, experience, and judgments made by the individuals completing the piping walkdowns. Observations include the use of instrumentation plus the use of perceptual inspections, listening for indicative noises, and the sense of touch, which can be used to determine the presence of high-frequency vibration. *Caution must be used when touching high-temperature or high-energy piping.*

Qualitative evaluations assess the potential for detrimental vibration that may not be quantified by the vibration instrumentation. These evaluations also address the limitations inherent to the assumptions and analysis techniques used for quantifying the effects of the vibration on piping response.

Examples of the items that are addressed by the qualitative evaluations include the limitations of the vibration instrumentation and the quantitative analysis techniques and the effect of vibration on supports, equipment, and branch piping. Some specific examples are provided in paras. H-3.2.1 through H-3.2.4.

H-3.2.1 Vibration Instrumentation. Vibration instrumentation is designed to measure specific types and ranges of vibration. The capabilities and limitations of the instrumentation must be accounted for. For example, accelerometers are typically not sensitive to low-frequency vibration. If low-frequency vibration (e.g., less than 3 Hz) is present, then different instrumentation may be required to adequately quantify the vibration.

Additionally, some instrumentation such as displacement transducers, may have limited response to high-frequency vibration. Therefore, if high-frequency vibration is present, different instrumentation (e.g., accelerometers) may be required to obtain adequate measurements.

The limitations of the signal conditioning together with the data acquisition and reduction equipment must also be considered. For example, the types of filters used will affect the recorded data. Filters include high-pass, low-pass, and anti-aliasing filters.

H-3.2.2 Quantitative Analysis Techniques. The acceptance criteria provided in these guidelines are based on the allowable stress limit for fatigue of the piping material. The intent is to prevent a fatigue failure of the piping. However, parameters in addition to pipe fatigue stress can be important. These other factors are evaluated as part of the qualitative evaluation. Other factors include the capability of the support system to withstand the vibration and the effect of vibration on associated equipment and branch lines.

The simplified evaluation techniques are based on the piping vibrating in beam modes. High-frequency vibration may excite piping shell modes and can result in vibration that cannot be adequately evaluated using only beam mode analogies.

H-3.2.3 Piping Supports. Piping vibration can affect pipe supports by causing wear, loosening of threaded connections, and fatigue damage. These effects must be

Table H-1 Recommended Actions for Piping Vibration Problem Resolution

Action	Purpose	Example	Retest Required
Perform detailed analysis	Quantify stresses in localized area; detailed analysis performed to reduce conservatism in simplified analysis	Finite element analysis of stresses in fitting and/or piping structural stress analyses to more accurately quantify the vibrational deflected shape and corresponding stresses	No
Perform detailed testing	Quantify stresses in localized area; detailed testing performed to reduce conservatism in simplified analysis	Installation of strain gages on piping	No
Perform test- analysis correlation	Quantify pipe responses throughout system by correlating analysis input with test data	Use of dynamic pressure data for comparison with input or as input to hydraulic transient analysis	No
Modify piping and/or restraints	Reduce pipe stresses by reducing vibration amplitudes	Addition of rigid restraints	Yes
Determine and eliminate source of vibration	Reduce pipe stresses by eliminating or altering excitation forces	Addition or modification of restricting orifice or valve trim; change in operating procedure	Yes

evaluated if the vibration is judged significant enough to adversely affect the supports. Although the acceptance criteria for the simple span analogies are based on piping fatigue stress limits, the supports are obviously important since damage or failure of a support could adversely affect the vibrational response of the piping.

Quantitative evaluation of stress in the structural members comprising the support should be completed when significant vibrational loads are experienced.

The following are examples of qualitative evaluations of supports that should be completed as appropriate:

(a) Inspection for loose or missing nuts at threaded connections. Vibration, especially high-frequency vibration, tends to loosen threaded connections.

(b) Indications of wear at the interface of the piping and components of guide-type supports. Vibration can cause the piping to rub, potentially resulting in wear of both the piping outside wall and support components. For active restraints, especially snubbers, continuous vibration can cause degradation of internals (e.g., wear). Wear can also result between the clevis pin and clamp or end bracket.

(c) Moved, rotated, or misaligned pipe clamps. Moved, rotated, or misaligned pipe clamps can be indicative of piping dynamic transients or significant steady-state vibration.

H-3.2.4 Equipment. Piping vibration can adversely affect associated equipment such as pumps, valves, and orifices. Inline instrumentation can also be adversely affected. Qualitative evaluations are intended to also address the potential for vibration damage to equipment. Below are examples of items to consider.

(a) Cavitation results in piping vibration, which is evaluated through quantitative techniques. However cavitation can also cause wear, erosion, and pitting on the internal surface of valves, downstream piping, and orifices. The presence of significant cavitation, typically accompanied by continual or intermittent loud noise, may be reason to fail the qualitative evaluation, even if the quantitative evaluation indicates acceptable results.

(b) Vibration can affect equipment components. Vibration can affect components of the valve such as attached hydraulic and instrumentation tubing and valve yokes. The presence of high-frequency vibration at a valve could also be indicative of resonance of the valve internals.

(c) Vibration near a pump can be indicative of pump problems such as misalignment, bearing wear, flow recirculation, internal cavitation, or imbalance.

(d) Branch lines can be affected by vibration of the header piping especially if the header vibration frequency is near a structural natural frequency of the

branch piping. Branch piping can also be affected by the pressure pulses in the header being transmitted through the branch. This is especially true if an acoustic resonance of the branch piping is excited.

H-4 ALLOWABLE DISPLACEMENT LIMIT

The measured displacements obtained during the perceptual monitoring procedure (para. H-3) are compared with allowable displacement limits. The displacement limits are calculated using the beam models and corresponding equations given in Part 3, para. 5.1.1. These beam models correspond to conservative representations of the actual piping response. Guidance on the use of these models are provided in paras. H-4.1 and H-4.2.

H-4.1 Characteristic Span

Characteristic span is the span of piping (L, ft) that is used in the allowable displacement limit equations to obtain an allowable vibrational displacement (δ_{allow}) and is the length of pipe between adjacent vibrational node points. If vibrational node points cannot be determined, such as is the case with quasirandom vibration, a conservative characteristic span should be determined by using assumed node points. The location and orientation of the seismically rigid supports (e.g., snubbers, rigid struts, structural anchors, and equipment nozzles) can be used as assumed node points. The assumed node points are then used to determine the characteristic span.

Note that a conservative characteristic span is a length of pipe that is shorter than the actual vibrating span of pipe. As illustrated by the allowable displacement limit equations, the rate of decrease of δ_{allow} is proportional to the squared rate of decrease of the characteristic span (L).

H-4.2 Node Points

Node points are locations of zero pipe vibrational displacement ($\delta = 0$). Note that beam analogies that have one or both ends assumed to be fixed or clamped conservatively assume that node point locations experience zero rotation as well as zero displacement. Node points are most readily found when the piping is vibrating predominantly in a single mode of vibration. Node points will typically occur at seismically rigid restraints; however, node points may also occur in the middle of pipe spans. As discussed previously, assumed node point locations may have to be used for determining the characteristic span if actual node points cannot be determined.

It should be noted that node points are not always located at restraints. For example, snubbers limit vibrational motion to a predetermined velocity or acceleration value. If the piping is vibrating at a level below the predetermined value (e.g., below 0.02 g for certain mechanical snubbers or below 10 in./min velocity for some hydraulic snubbers), the snubber will not restrain the piping and the restraint location, therefore, need not be considered as a node point.

In addition, some restraints may have gaps or free play of sufficient magnitude to allow unrestrained piping vibrations of a magnitude less than or equal to the restraint gaps or free play. For piping vibrational displacements of a magnitude less than or equal to the restraint gaps or free play, the restraint locations need not be considered as node points.

PART 3
NONMANDATORY APPENDIX I
Acceleration Limits for Small Branch Piping

The intent of the acceleration method is to provide screening acceleration limits as a supplement to the displacement limits discussed in Part 3, para. 5 for small branch piping (pipe sizes ≤ 2 in.) with significant masses cantilevered from header piping or equipment. This method is intended to provide a conservative representation of the vibrational stresses in the branch connection between the small branch piping and the header.

These limits can be used to screen out configurations with acceptable vibration levels from those that may be unacceptable or may require more detailed evaluations to demonstrate the acceptability of the vibration. This method is intended to be a supplement to the displacement methods provided in Part 3, para. 5.1.1 when high accelerations are present.

Note that the limits resulting from this approach should be conservative and exceeding these limits does not necessarily indicate that the allowable stresses of Part 3, para. 3 have been exceeded (see also precautions below). For the vibration to pass these screening limits, the measured vibration must be below both the limits determined by the methods of Part 3, para. 5.1.1 and the criteria below. Alternatively more detailed testing and/or analysis can be used to demonstrate that the vibration stresses are below the limits of Part 3, para. 3.

Significant vibrational stresses can occur when small branch piping (pipe sizes ≤ 2 in.) cantilevered to header piping is driven as a rigid body at a high acceleration. In these cases, allowable acceleration limits based on the allowable stress amplitudes of Part 3, para. 3 can be used to evaluate the vibrational stresses. The acceleration limits discussed below provide a simplified method for quickly determining acceleration limits for these types of installations.

The equation for peak acceleration (α_A) limits in units of g is:

$$\alpha_A = \frac{S_{\mathrm{el}} \times z}{\alpha \times C_2K_2 \times W_T L_E} \times \epsilon$$

where

C_2, K_2 = stress indices defined in Part 3, para. 3.2.1

L_E = a conservative value for the effective length in inches (meters) from the branch connection (at the location of the girth fillet weld) to the center of gravity of the masses that make up W_T

S_{el} = alternating stress from Part 3, para. 3.2.1

W_T = the total weight in pounds (kilograms) of all lumped masses including valves, fittings, flanges, the pipe itself, the pipe contents, and insulation

z = section modulus of branch pipe, in.^{3} (m^3)

α = stress reduction factor from Part 3, para. 3.2.1

ϵ = unit conversion factor equal to 1.0 when the U.S. Customary units specified below are used and equal to 10.197 × − 10^4 when the metric units specified in parentheses are used

EXAMPLE APPLICATION: A peak stress index (C_2K_2 or $2i$) equal to 4.2, which corresponds to a girth fillet weld is incorporated into the acceleration limit equation. The acceleration limit equation should be changed accordingly when other values of C_2K_2 are applicable.

A $\frac{3}{4}$ in. Schedule 80 cantilevered branch line is accelerated by a header pipe at a peak acceleration of 1.0 g (zero to peak). The branch line contains a 15-lb valve that is 6 in. from the branch connection. It is determined that L_E = 6 in. and W_T = 16.6 lb (see Fig. I-1 for determination of L_E and W_T). Determine if the measured acceleration falls within the simplified acceleration limit.

For carbon steels with a UTS ≤ 80 ksi, the equation for allowable acceleration in units of g is shown below. The equation below also assumes that $C_2K_2 = 4.2$.

$$a_A = \frac{1{,}830z}{W_T L_E}$$

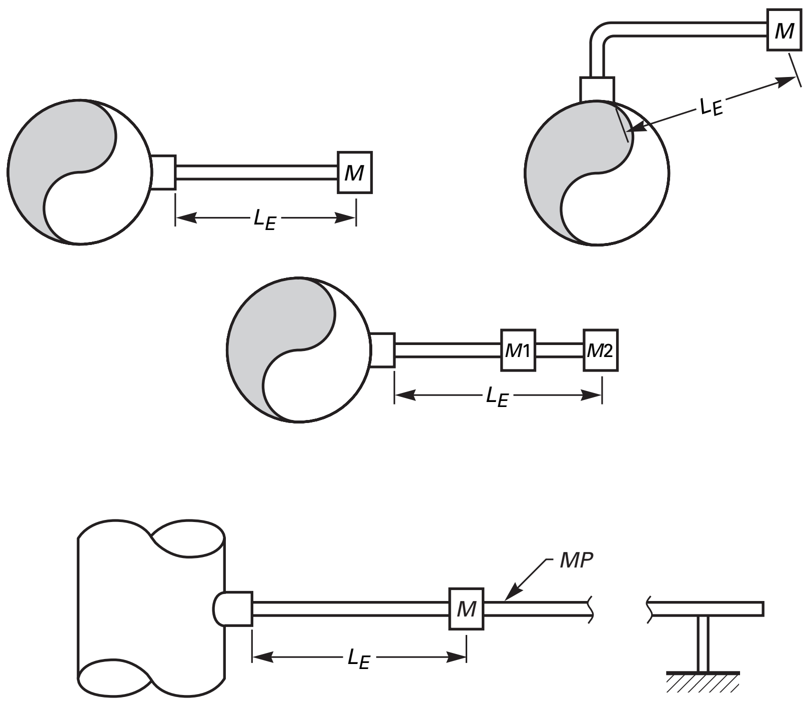
$$a_A = \frac{1{,}830z}{W_T L_E} = \frac{(1{,}830 \times 0.0853)}{(16.6 \times 6)} = 1.57\,g > 1.0\,g$$

The vibration is acceptable.

CAUTION: Acceleration measurements often result in large overall values especially if high-frequency accelerations are present. It is important to note that these high-frequency accelerations likely will not affect the piping as assumed by the criteria provided herein. The acceleration limit is based on the assumption that the dynamic accelerations affect the piping equivalent to static accelerations. Using this assumption for the high-frequency accelerations (where high frequency can be taken as frequencies above the fundamental frequency of the small branch line) may result in overly conservative results.

Some piping configurations and operating conditions, for example, instrument lines branching off process piping, can be excited in higher-order modes (i.e., one or more node points exist

Fig. I-1 Determination of L_E and W_T



where

W = weight of pipe within length L_E
W_C = weight of contents within length L_E
W_I = weight of insulation within length L_E
W_M, W_{M1}, W_{M2} = weight of concentrated masses (valves, fittings, flanges, etc.)
W_{MP} = weight of pipe, contents, and insulation outside length L_E to first rigid support or snubber in direction of vibration

between the branch connection and the measurement location). This type of vibration is indicated by large accelerations occurring along with small displacements at locations several feet from the branch connection. In addition, local effects can result in high accelerations that are transmitted through the shell and do not affect the global structural vibration mode of the small branch piping. The criterion presented in this Appendix is not applicable for this type of vibration; however, if used, the acceleration limit should be conservative. In general, more detailed analyses are required to evaluate the vibration.

PART 12

PART 12
Loose Part Monitoring in Light-Water Reactor Power Plants

1 INTRODUCTION

1.1 Scope

This Part establishes the requirements for loose part monitoring in light-water reactor (LWR) power plants. Loose part monitoring is required for the reactor vessel and primary coolant system in a pressurized water reactor (PWR) and the reactor recirculation system in a boiling-water reactor (BWR). This Part establishes monitoring methods, intervals, parameters to be measured and evaluated, and records requirements.

1.2 Overview

Loose part monitors (LPMs) provide a means for detecting and evaluating metallic loose parts through analysis of transient acoustic signals produced by loose part impacts. Installed systems use an array of externally mounted accelerometers located where loose parts are most likely to collect. Most systems include automatic annunciation (audible and visual) of a potential loose part, audio monitoring, and both automatic and manual signal recording.

High false alarm rates have been the major generic problem for LPMs and have reduced confidence in the information obtained from LPMs. The origins of false alarms are diverse and range from random variations in background noise levels to metallic impacts not caused by loose parts within the reactor coolant system. This Part, therefore, recommends that system sensitivity be set on the basis of background noise and to achieve the maximum sensitivity commensurate with an acceptable false alarm rate when the system has been installed in accordance with this Part.

Paragraph 2 defines the terms used in this Part; because loose part monitoring is unique, some terms may deviate from definitions used in other Parts. Paragraph 4 deals with loose part monitoring system instrumentation and its installation; it is intended that para. 4 serve as the basis for the design and installation of new or replacement systems. Paragraph 5 presents the basis for a comprehensive loose part monitoring program and is intended for use with all current and future systems.

2 DEFINITIONS

These definitions are provided to ensure a uniform understanding of selected terms used in this Part.

accelerometer: a transducer, typically piezoelectric, for converting acceleration to an electrostatic charge.

active channel: an LPM channel used by the alarm annunciator circuitry.

A/D: analog to digital.

ALARA: as low as reasonably achievable.

alarm condition: the LPM state indicating that the alert/alarm processor has detected characteristics indicative of a loose part.

alert/alarm processor: a device to process alert signals to discriminate between a valid loose part event and a false alarm.

alert level: a preestablished value against which the conditioned transducer signal level is compared to indicate the possibility of a loose part.

background noise: the combination of flow, structural, and electrical noise.

baseline: reference data used for system performance evaluation and signal analysis.

break frequency: the frequency at which the signal is attenuated by 3 dB relative to the passband.

BWR: boiling-water reactor.

calibration: a test during which known inputs are applied to a component and corresponding output readings are recorded to establish a baseline to compare with a previously established baseline or to adjust the component within specifications.

collection region: a region within the primary reactor coolant system in which loose parts tend to collect as a result of localized low flow rates or mechanical obstructions.

delay time: the difference in time required for the acoustic wave initiated by an impact to reach different loose part sensors.

dynamic range: the useful range of an electronic instrument over which the signal information is not compromised by instrument overload (distortion) or by electronic background noise.

electrical noise: any spurious electrical signal that contaminates the transmission, measurement, or recording of the desired signal.

false alarm: an alarm that occurs when there is no loose part; two types are addressed by this Part.

Type 1: a system alarm to a nonimpact signal such as electrical noise.

Type 2: a system alarm to a metallic impact signal that is not a loose part.

field cable: the signal cable connecting the remote charge converter/preamplifier to the signal-conditioning and processing equipment.

field equipment: that portion of the installed LPM not in the control cabinet.

filter: a device for selecting signal components on the basis of their frequency. It allows components in one (or more) frequency band(s) to pass while attenuating components in other frequency bands.

flow noise: acoustic energy generated by the flow of coolant in the primary coolant system.

frequency domain: the characterization of a signal as a function of frequency.

g: the unit of acceleration due to gravity at the earth's surface, which for engineering purposes is 32.17 ft/sec^2 (9.81 m/s^2).

hardline cable: coaxial or triaxial cable with one or more metal sheaths insulated from the conductor by a mineral oxide; this type of cable is used to transmit the accelerometer signal to a charge conversion device in high temperature, humidity, and/or radiation environments.

impact energy: the kinetic energy of an impacting object.

impact test: a test to determine system functionality and response characteristics to a known metallic impact.

instrumented hammer: a hammer instrumented with a transducer to convert the hammer impact force or energy into an electrical signal.

IRIG: inter-range instrumentation group, a group establishing performance specifications for analog tape recording equipment.

loose part: two types are addressed.

free: a metallic object that is disengaged and free to drift.

captive: a constrained metallic part that can impact nearby components.

LPM: loose part monitor.

LWR: light-water reactor.

OTSG: once-through steam generator.

passive channel: an LPM channel that is not used by the alarm circuitry but that may readily be placed in service if needed.

power spectral density: the real-valued continuous function of frequency, presented with frequency on the horizontal axis and density on the vertical axis. The units of density are those of the data squared per unit of frequency; for example, for acceleration data in g the units would be g^2/Hz.

PSD: power spectral density.

PWR: pressurized water reactor.

RCP: reactor coolant pump.

RCS: reactor coolant system.

remote charge amplifier: a device that accepts the electrostatic charge output from a piezoelectric accelerometer and produces an amplified voltage output; these devices can accept a wider range of input resistance and capacitance than a remote charge converter/preamplifier and typically provide variable gain.

remote charge converter/preamplifier: a charge conversion device that accepts the electrostatic charge output from a piezoelectric accelerometer and provides a low impedance output signal for transmission to control room electronics.

resonance: the condition in which the natural frequency of a mechanical system is matched in frequency by an external vibration stimulus, resulting in higher vibration levels than would occur otherwise.

signal conditioner: a device that converts the signal transmitted from the remote charge converter/preamplifier to a form suitable for detection and recording; it may also provide electrical power to a remote charge converter.

signal-to-noise (S/N) ratio: the ratio of signal amplitude to noise amplitude.

slew rate: the maximum rate at which the output of an electrical device can change while operating within its linear range.

softline cable: coaxial or triaxial cable used to transmit the charge signal from an accelerometer to a charge conversion device; these cables, specially treated to minimize triboelectric noise, are flexible but less resistant to heat and radiation than hardline cables.

threshold detector: a circuit or device that monitors an LPM channel and provides an indication when the signal exceeds the alert level.

time domain: the characterization of a signal as a function of time.

triboelectric noise: the charge signal generated by movement of the signal cable.

white noise: a random signal characterized by constant spectral density independent of frequency.

3 REFERENCES

The following is a list of publications referenced or used in developing this Part.

ANSI S2.10-1971, American National Standard Medthods for Analysis and Presentation of Shock and Vibration Data

ANSI S2.11-1969, American National Standard for the Selection of Calibrations and Tests for Electrical

Transducers Used for Monitoring Shock and Vibration
Publisher: American National Standards Institute (ANSI), 25 West 43rd Street, New York, NY 10036.

Regulatory Guide 1.133, Revision 1, Loose Part Detection Program for the Primary System of Light-Water Cooled Reactors, U. S. Nuclear Regulatory Commission, 1981
Publisher: Superintendent of Documents, United States Government Printing Office, Washington, DC 20402.

4 EQUIPMENT

4.1 General

This Section describes the major components of a loose part monitoring system: the sensor array and its cabling; the signal processing, detection, and data recording subsystems; analysis equipment; and documentation. Concern for personnel radiation exposure and safety has been included in developing system requirements.

Reactor coolant system background noise makes the detection of loose parts difficult because it masks the noise generated by loose part impacts; it is a composite of noise from sources such as coolant flow and mechanically and hydraulically generated vibration. Typically, background noise extends over a very wide frequency band but may have significant peaks in narrower frequency bands.

Waveforms from impacts near an accelerometer are significantly different in character than the background noise, as demonstrated in Fig. 1. However, impacts farther from the accelerometer (typified by the one shown in Fig. 2) are more difficult to detect because characteristics such as the impact shape become less distinct and the amplitude is decreased.

Impact signals contain significant information about the size of the impacting object and the impact force and energy. The general range of loose part impact signal amplitude and frequency content for masses between 0.5 lb and 30 lb (0.23 kg and 13.61 kg) is shown in Fig. 3. The composition and shape of both the component struck and the impacting object further affect the impact signal.

4.2 Field Equipment

This part of the system is composed of an externally mounted accelerometer, a sensor cable, a remote charge converter/preamplifier, and a field cable to the control cabinet electronics. Alternatively, a remote charge amplifier may be used instead of a remote charge converter/preamplifier. See Fig. 4 for details. Field components shall be selected to perform in the temperature/humidity/radiation environments normally expected at the chosen location.

4.2.1 Accelerometer. The general requirements for piezoelectric accelerometers are as follows:

(a) sensitivity: fixed, in the range 10 pC/g to 50 pC/g
(b) working range: 0.01 g to 100 g peak
(c) charge temperature response: less than ±15% from 60°F to 625°F (15.6°C to 329.4°C)
(d) radiation resistance: vendor tested for use in a nuclear environment
(e) operating temperature range: 60°F to 625°F (15.6°C to 329.4°C)
(f) frequency response: flat within –5% to ±10% from 5 Hz to 8 kHz, uniformly increasing response to the first resonance (first resonance greater than 20 kHz)
(g) electrical/mechanical: case isolated from signal ground (see para. 4.3.6)
(h) calibration: performed by the manufacturer or recognized test/calibration laboratory using a procedure that incorporates ANSI S2.11-1969

4.2.2 Accelerometer Mounting. There are two acceptable mounting methods:

(a) direct mounting: stud mount the accelerometer directly to the component as shown in Fig. 5.
(b) fixture mounting: stud mount the accelerometer to a mounting fixture attached to a component by mechanical means such as straps, clamps, or welds. Accelerometers may be mounted to bolts that are then inserted into existing threaded holes in primary coolant system components. Figure 6 shows one example of fixture mounting.

In no case shall accelerometers be magnetically mounted because of the poor frequency response obtained and the difficulty in maintaining a tight mechanical connection.

4.2.3 Accelerometer Installation. Installation of accelerometers shall conform to the following requirements.

(a) Use only the mounting studs provided by the accelerometer manufacturer or mounts fabricated to the manufacturer's specifications to preclude accelerometer damage and to ensure proper acoustic coupling.
(b) The manufacturer's recommendations for sensor installation shall be followed (including torque value).
(c) The mounting surface shall be finished to a surface roughness of 125 μin. (3.2 μm) rms or better.
(d) Acoustic couplants shall not be used because they degrade in the harsh environment.
(e) The mounting hole shall be perpendicular to the mounting surface within ±1 deg.
(f) Mounts shall be drilled and tapped so that the stud does not bottom in its hole.
(g) The threads shall be visually verified to be clean.
(h) Drilled-and-tapped or weldment mounts shall conform to ASME Code requirements.
(i) Clamped fixtures mounted on cylindrical surfaces shall have a two-line contact surface similar to that shown in Fig. 6.

Fig. 1 Typical Broadband Sensor Response to Nearby Impact

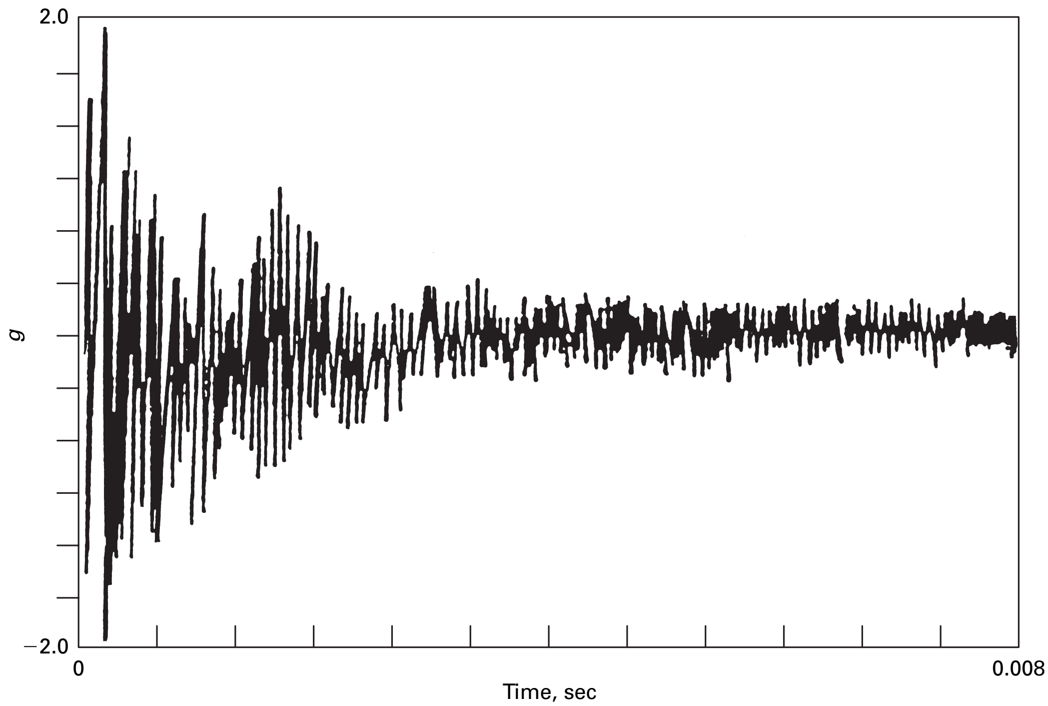


Fig. 2 Typical Broadband Sensor Response to More Distant Impact

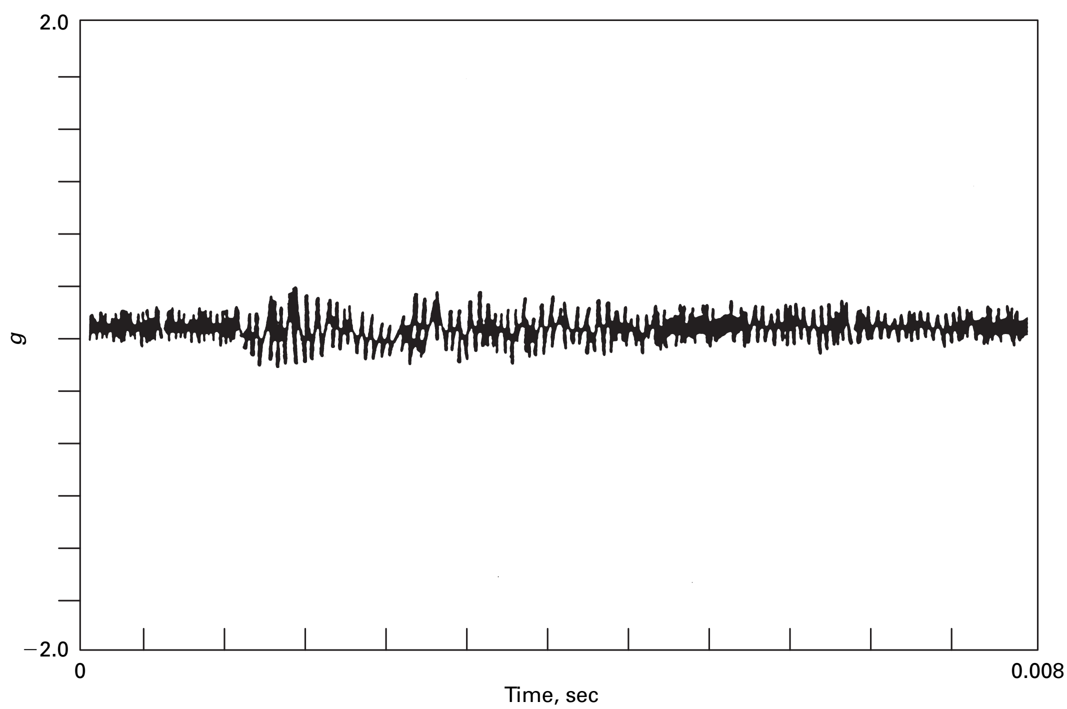


Fig. 3 Range of Loose Part Signal Amplitude and Predominant Frequency Content

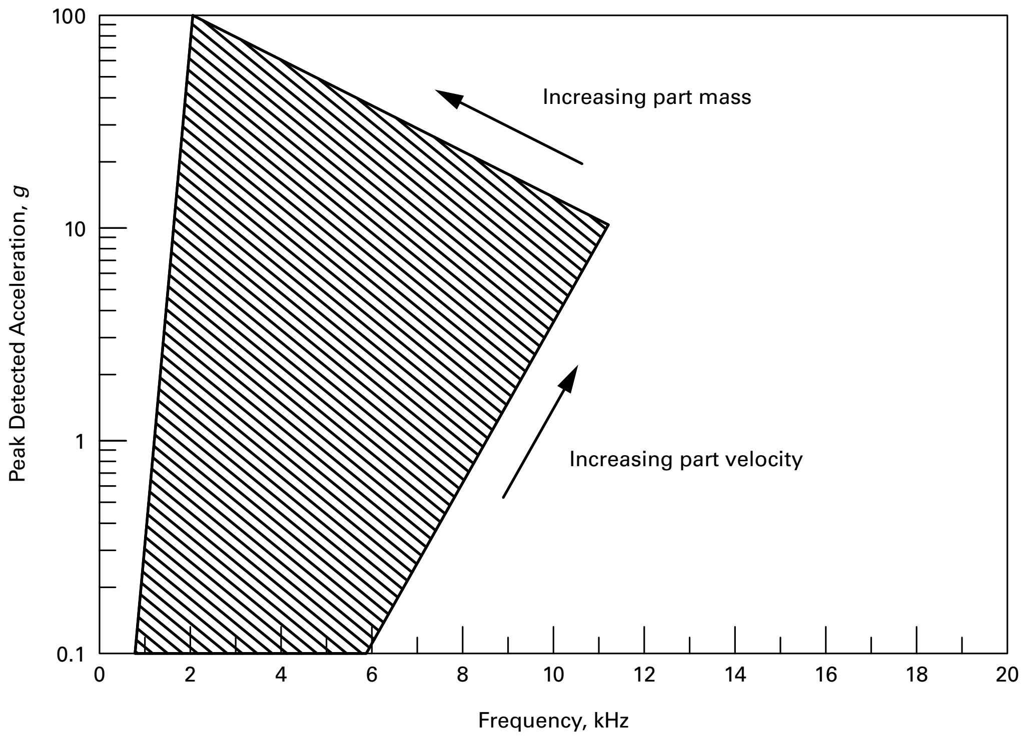
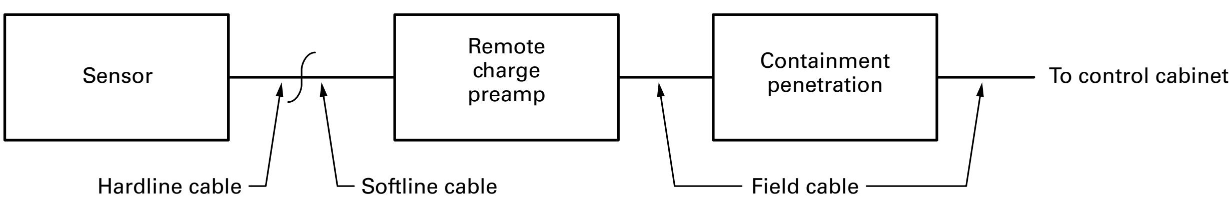
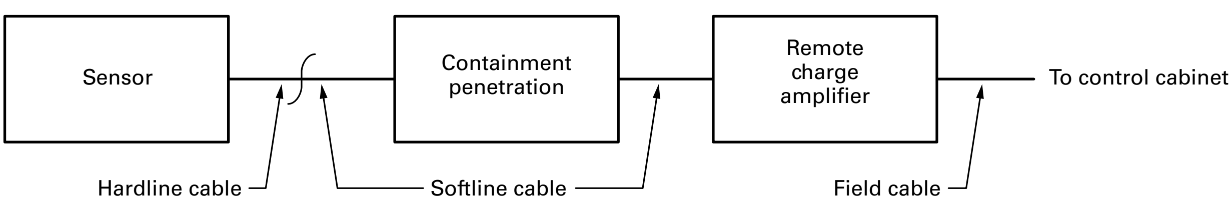


Fig. 4 Field Equipment



(a) For Remote Charge Preamplifier Inside Containment



(b) For Remote Charge Amplifier Outside Containment

Fig. 5 Direct Stud Mount

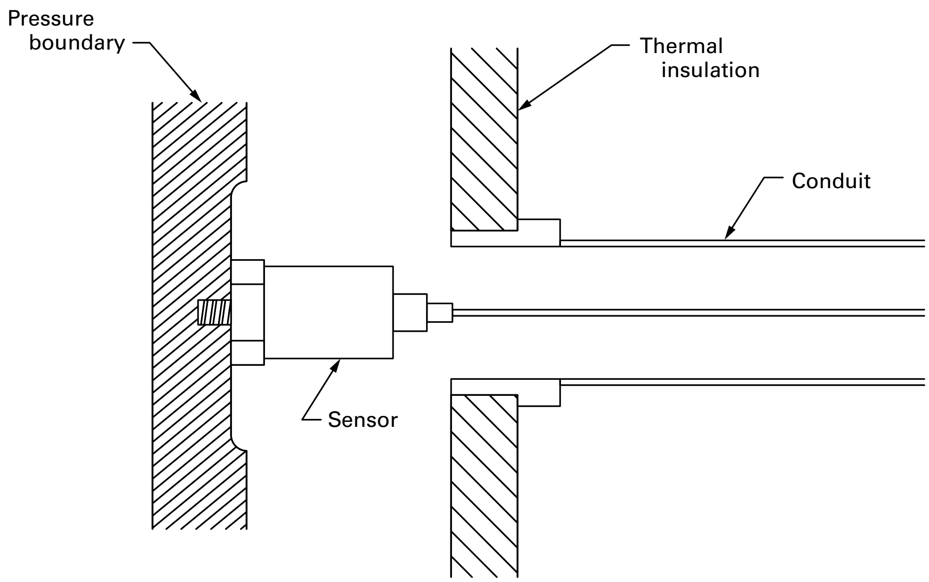
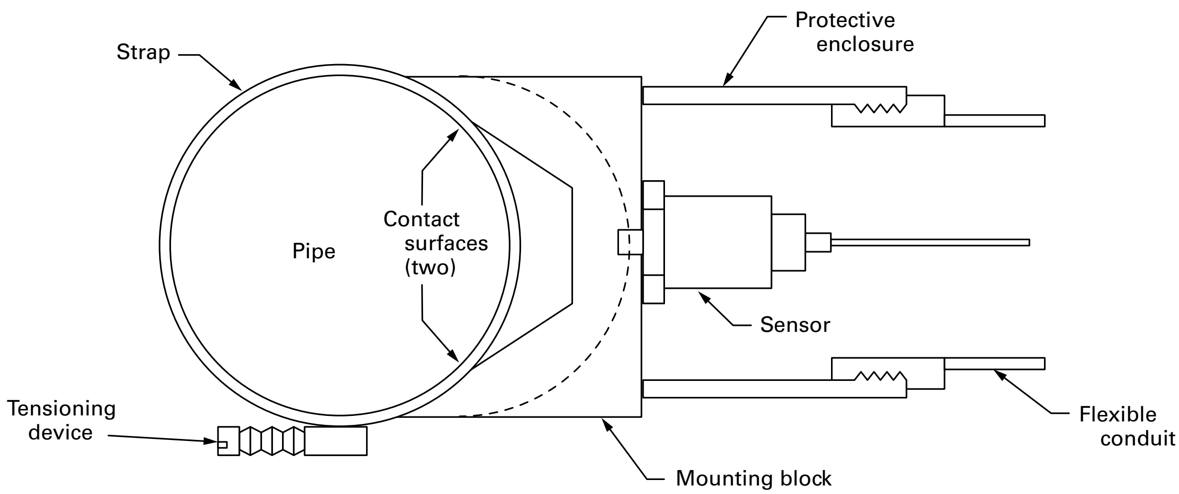


Fig. 6 Clamped Mount



(j) Mounts and fixtures shall be designed to compensate for thermal expansion so as to provide an approximately constant holding force throughout the operating temperature range.

(k) Sensors shall be protected from mechanical damage. Enclosures or covers of sufficient size for access and maintenance shall be used for accelerometers mounted external to mirror insulation. Mounting under mirror insulation without an additional enclosure is acceptable.

(l) Enclosures and conduit shall be acoustically isolated from the accelerometer and its mounting. Acceptable acoustic isolation may include a flexible conduit.

(m) The area in the vicinity of the sensor shall be inspected for loose metallic components (e.g., insulation, identification tags, and chains) that could impact on or near a sensor. All loose components shall be restrained.

4.2.4 Accelerometer Locations — PWR. In PWR applications, the recommended sensor locations for detection and analysis of metallic impact signals in the RCS are listed in Table 1. Care should be taken to select locations that are accessible from permanently installed ladders and platforms.

The three upper reactor vessel accelerometers shall be located at approximately 120 deg intervals around the top of the vessel or the reactor vessel head at an elevation no higher than the lifting lugs. Lifting lug mounting, if used, shall be such that it does not interfere with the

Table 1 Recommended PWR Accelerometer Locations

Location	Number of Sensors
Reactor vessel, upper	3
Reactor vessel, lower	3
Steam generator (each)	3
Reactor coolant pump (each)	1

lifting rod connected to the lug. The three lower reactor vessel accelerometers shall be mounted to the incore guide tubes within 18 in. (0.45 m) of the reactor vessel. The accelerometers should be approximately 120 deg apart and two-thirds the radial distance outward from the vessel axis. In plants without lower vessel incore guide tubes, the lower reactor vessel accelerometers shall be mounted to the reactor vessel.

For U-tube steam generators, mount one accelerometer above and one below the tube sheet in a vertical array on the primary inlet side. The third accelerometer shall be mounted on the shell near the top of the tube bundle. Figure 7 shows a typical sensor array for U-tube steam generators.

For OTSG, two accelerometers should be located near the upper tube sheet, approximately 180 deg apart, and one accelerometer should be located at the lower tube sheet. Figure 8 shows the recommended array for an OTSG.

Install one accelerometer on each reactor coolant pump. The sensor should be mounted to a lifting lug or other location on the pump bowl. The location should be selected to avoid sensor damage during pump maintenance.

4.2.5 Accelerometer Locations — BWR. For BWR applications, the recommended sensor locations are specified in Table 2.

Accelerometers mounted at the main steam outlet, feedwater inlet, and recirculation water outlet elevations shall be attached to convenient nozzles (such as instrument taps) as close to the vessel as possible. When possible, avoid pipes and lines with flow during operation. The locations selected shall have good acoustic coupling to the reactor vessel and should be equally spaced around the circumference. The three lower vessel accelerometers shall be mounted to the control rod drive housings as near the reactor vessel as practical; they should be approximately 120 deg apart and placed on peripheral drive housings. Figure 9 shows the recommended BWR sensor array.

Install one accelerometer on each recirculation pump. The sensor should be mounted to a lifting lug or other location on the pump bowl. The location should be selected to avoid sensor damage during pump maintenance. Install one accelerometer on each recirculation loop discharge pipe near the recirculation header.

4.2.6 Sensor Cable. The cable between the sensor and the remote charge converter/preamplifier or remote charge amplifier shall be of a type designed for use with low level charge signals generated by accelerometers. Low noise, hardline cable is required under thermal insulation covering components and piping. High temperature, low noise softline cable may be used outside this region when the temperature is less than 400°F (204°C). Hardline cable lengths greater than 20 ft (6.1 m) are discouraged. Connection locations should permit access for inspection and maintenance.

The sensor cable shall be completely enclosed in conduit. To prevent ground loops and to provide additional acoustic isolation, the hardline cable sheath and intermediate connectors shall be insulated with temperature- and radiation-resistant material to avoid contact with the conduit. Triaxial hardline cable affords additional protection against ground loops. Protection against chafing of the cable and insulation at the conduit exit points is required.

4.2.7 Remote Charge Converter/Preamplifier. The remote charge converter shall be located as close as possible to the accelerometer without surpassing the temperature and radiation limitations (including radiation from withdrawn incore detectors). The converter shall be mounted inside a junction box to provide physical protection. Safe personnel access to the junction boxes from permanently installed ladders and platforms shall be provided. Remote charge converters shall meet the following requirements:

(a) operational temperature: 60°F to 212°F (15.6°C to 100°C)

(b) gain: fixed, in the range 1 mV/pC to 10 mV/pC

(c) radiation resistance: vendor tested for use in a nuclear environment

(d) frequency response: flat within ±5% from 5 kHz to 20 kHz

(e) input resistance and capacitance: compatible with combined accelerometer/sensor cable values at maximum operating temperature

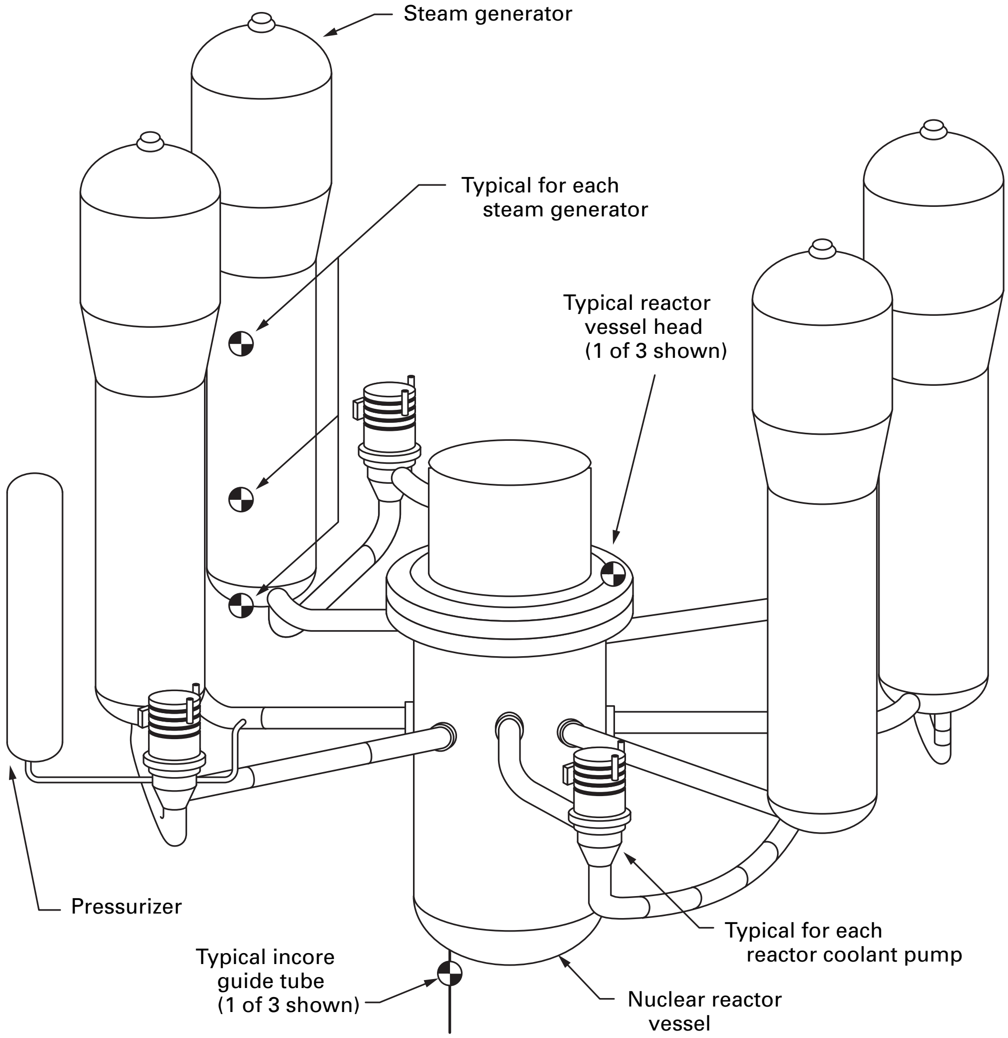
(f) input range: charge equivalent to at least 100 g peak without overload

(g) electrical: installed so that both the signal and reference are isolated from ground

(h) output: capable of driving the combined field cabling and control cabinet electronics load at a signal level of 100 g peak and 20 kHz without amplitude or slew-rate limiting

4.2.8 Remote Charge Amplifier. Remote charge amplifiers may be used outside containment and shall not be used in containment unless they meet the environmental requirements for remote charge converters. Remote charge amplifiers shall meet the following requirements:

Fig. 7 Recommended Sensor Array for PWR With U-Tube Steam Generator



GENERAL NOTE: = LPM sensor

(a) operational temperature: 60°F to 130°F (15.6°C to 54.4°C if used outside containment)

(b) gain: selectable, in the range 1 mV/pC to 10 mV/pC

(c) frequency response: flat within ±5% from 5 kHz to 20 kHz

(d) input resistance and capacitance: compatible with combined accelerometer/sensor cable values at maximum operating temperature

(e) input range: charge equivalent to at least 100 g peak without overload

(f) electrical: installed so that both the signal and reference are isolated from ground

(g) output: capable of driving the combined field cabling and control cabinet electronic load at a signal level of 100 g peak and 20 kHz without amplitude or slew-rate limiting

4.3 Control Cabinet Equipment

4.3.1 Signal Conditioner. The signal conditioner shall incorporate the following features:

(a) Frequency response: flat within ±5% from 5 kHz to 20 kHz.

(b) Filters: 18 dB/octave or greater attenuation rate with minimum stop band rejection of at least 60 dB. Filters may be either fixed or selectable with the suggested high-pass break frequency between 500 Hz and 2 kHz and the low-pass between 8 kHz and 12 kHz.

(c) Test connector providing unfiltered or selectable filtered/unfiltered signal for analysis and recording.

(d) Dynamic range: signal level equivalent to at least 100 g peak in the least-sensitive range.

(e) Output shall be calibrated in units of g/V.

Fig. 8 Recommended Sensor Array for PWR With Once-Through Steam Generator

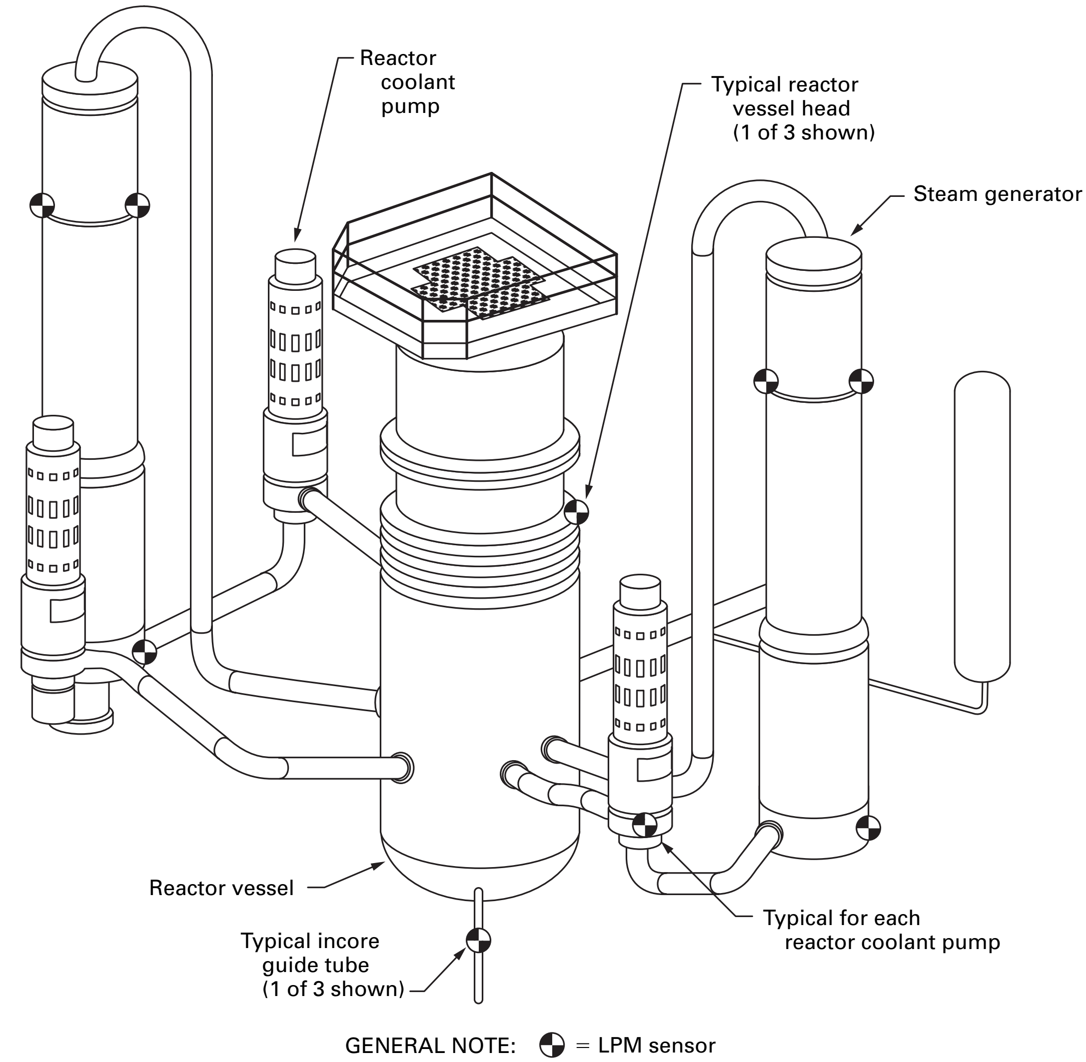


Table 2 Recommended BWR Accelerometer Locations

Location	Number of Sensors
Main steam outlet elevation	2
Feedwater inlet elevation	4
Recirculation water outlet elevation	2
Recirculation pump (each)	1
Recirculation discharge pipe (each)	1
Reactor vessel bottom	3

(f) Over-range and under-range indication (unless provided in either the detector or discriminator circuitry) or signal level indication.

(g) Convenient measurement of remote charge converter/preamplifier bias voltage or current.

(h) Convenient indication of gain or range if externally adjustable.

(i) Electrical compatibility with accelerometer and charge converter.

(j) External controls affecting calibration and alarm setpoints shall be designed to prevent inadvertent movement.

4.3.2 Threshold Detector

(a) Each channel shall have a separate threshold adjustment.

(b) Detector may use either absolute or variable level detection techniques.

(c) Variable alert levels shall be proportional to the magnitude of the band-limited background.

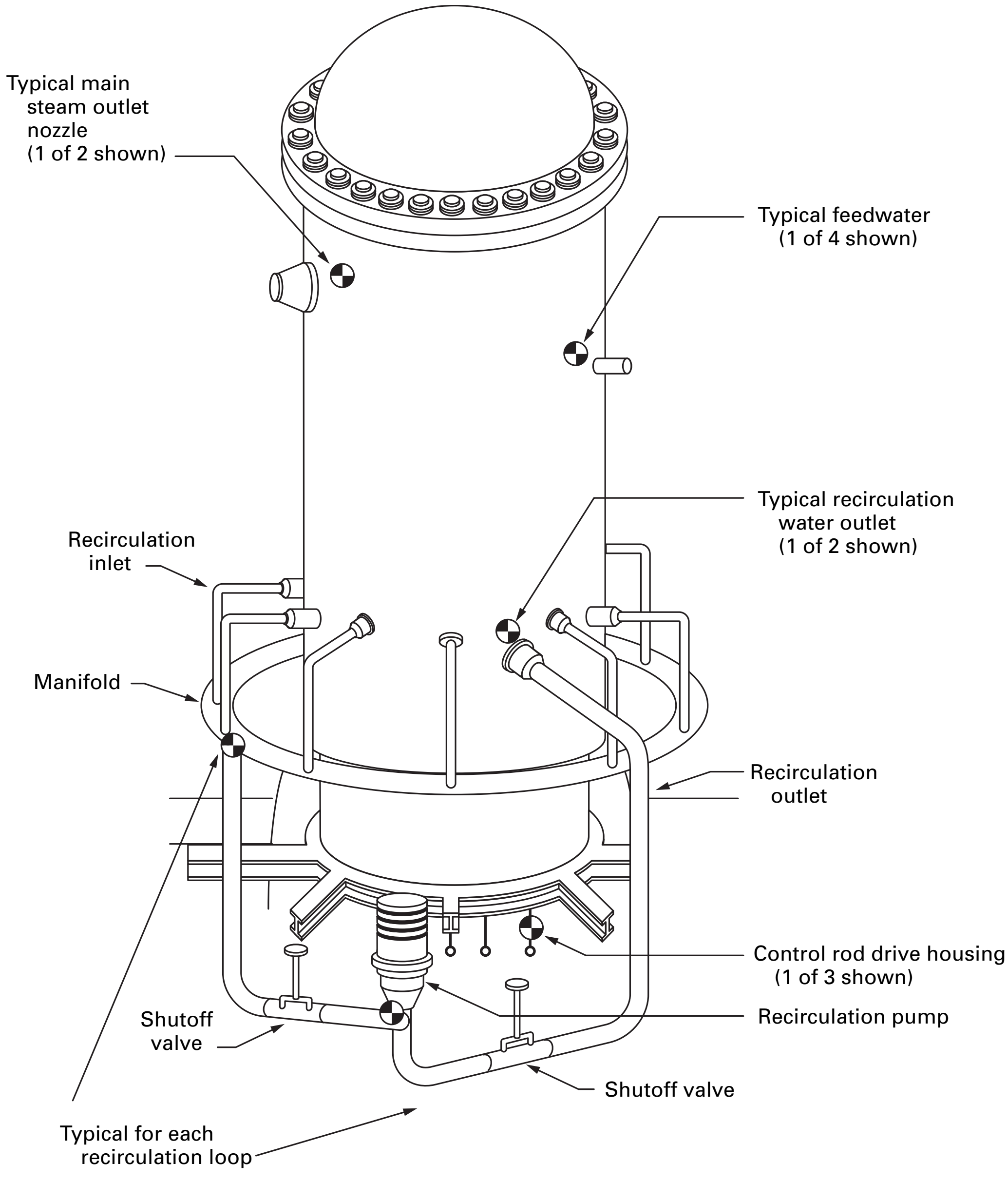
4.3.3 Alert/Alarm Processor

(a) Rejects alert patterns not meeting preestablished criteria.

(b) Automatic alert reset if alarm criteria are not met.

(c) Visually indicates channel(s) in an alert condition.

Fig. 9 Recommended Sensor Array for BWR



GENERAL NOTE: ◐ = LPM sensor

(d) Indication of the first channel to alert.

(e) Audibly indicates that the system is in the alarm state.

(f) Manual alarm reset in the control cabinet.

(g) Automatic initiation of data recording or storage when the alarm condition is entered.

(h) Alarm indication to the plant annunciation/computer system; the alarm shall be annunciated in the control room on a unique (nonganged) alarm.

4.3.4 Recorder. The system shall be capable of automatically recording the initiating event and for 2 min to 5 min after the event. The filtered signal shall be stored in a format such that it can be electronically reproduced for further analysis. It may be necessary to use both a transient recording device to capture the initial event and a second device for continuous recording. The continuous recording device may be either analog or digital.

(a) Transient Recorder

(1) trigger data storage on alarm

(2) pretriggering to ensure capture of entire waveform

(3) data storage shall continue until the continuous recorder is operating

(4) 50 kHz sampling rate per channel (minimum)

(5) 12 bit A/D converter (minimum)

(6) simultaneous recording of all signal channels required in para. 4.2.4 or 4.2.5

(b) Continuous Analog Recorder

(1) frequency response: flat within ±5% from 1 kHz to 10 kHz, recommended to be flat within ±10% from 1 Hz to 20 kHz (additional specification)

(2) simultaneous and continuous recording (for at least 2 min) of the channels required by para. 4.2.4 or 4.2.5

(3) recorder configured to IRIG standards

(4) recording of a time code providing date and time to the nearest second

(c) Continuous Digital Waveform Recording

(1) simultaneous and continuous recording (for at least 2 min) of the channels required by para. 4.2.4 or 4.2.5

(2) 50 kHz sampling rate per channel (minimum)

(3) 12 bit A/D converter (minimum)

(4) recording of a time code providing date and time to the nearest second

4.3.5 Audio Monitor. The audio monitor shall incorporate the following features:

(a) amplifier frequency response: flat within ±1 dB from 30 Hz to 15 kHz

(b) headphone output

(c) speaker frequency response: rated response from 100 Hz to 15 kHz

(d) switching capability to permit audio monitoring of any LPM channel or previously recorded channel

(e) inputs shall be selectable to permit use of either the signal conditioner unfiltered output or a normally filtered output

(f) volume control independent of signal conditioner gain

4.3.6 Cabling and Grounding. The LPM shall be designed to provide adequate signal shielding and to avoid ground loops. For systems using single-ended remote charge converters/preamplifiers, the system shall be installed with a single point ground at the control cabinet. The accelerometer, sensor cable, remote charge preamplifier, and field cabling shall be electrically isolated from building or safety grounds.

The field cabling shall be twisted, shielded-pair–type or triaxial-type cable. The shield shall be electrically isolated from both the signal and signal reference leads and shall be grounded in the signal cabinet. Signal and shield integrity shall be maintained through penetrations, and only instrument-quality, low-level signal penetrations shall be used. Channels monitoring a single collection region shall be routed separately to minimize common-mode failure. Fiber optic cable may be used in appropriate environments.

4.4 Analysis and Diagnostic Equipment

4.4.1 General. The instrumentation needed to perform the various analyses described in this Part include a data recorder, a digital oscilloscope (or similar instrument to capture transient waveforms), a frequency analyzer, and a printer/plotter to supply a hard copy of analyzed data. Multifunction instruments that perform one or more of these functions may be used in lieu of individual instruments. This instrumentation can be included in the control cabinet electronics and may be used for diagnostics if analysis does not require removing the LPM from service.

4.4.2 Data Reproducer. Separate data reproduction equipment compatible with para. 4.3.4 shall be available for diagnostic analysis if the control cabinet recorder(s) cannot be used for diagnostics without compromising the LPM detection and alarm functions.

4.4.3 Waveform Analyzer. The waveform analyzer shall have

(a) minimum of two channels

(b) variable sampling rate, with a maximum sampling rate no less than 50 kHz per channel

(c) capability to store and display waveforms containing no less than 4,000 points per channel

(d) capability to store and display captured transient waveforms in adjustable time spans from at least 10 to 40 ms

(e) pre- and post-trigger capture feature

(f) 12 bit or higher A/D converter resolution

(g) ability to trigger on selected channel or on external trigger

(h) adjustable trigger threshold

4.4.4 Frequency Analyzer. The frequency analyzer shall have

(a) frequency range: 0 kHz to 25 kHz, min.

(b) 12 bit or higher A/D converter resolution

(c) summation averaging selectable in steps up to at least 256 samples per average

(d) minimum resolution of 256 points in the frequency domain or zoom capability with 1 Hz resolution

(e) automatic indication and selectable rejection of overload signals

(f) ability to store frequency domain results for comparison to other data

(g) ability to process nonzero mean time value signals

4.4.5 Hard Copy. A printer or plotter that is capable of producing annotated hard copy information from the time and frequency domain analysis equipment.

5 PROGRAM ELEMENTS

5.1 General

This Section is intended to assist nuclear utilities in implementing a program to detect and diagnose loose parts.

5.2 ALARA

An LPM program will require occasional work in radiation areas. Those activities should be closely coordinated with plant ALARA programs. In particular, the following should be implemented.

(a) Equipment used in the LPM should be reliable to minimize the need for maintenance.

(b) LPM containment components should be easily replaceable to minimize exposure time during maintenance.

(c) LPM components should be accessible from permanent ladders and platforms to reduce personnel time in containment.

(d) Charge converters/preamplifiers should be mounted in locations that serve to reduce personnel exposure and to increase equipment reliability.

(e) Maintenance and calibration should be planned and, if necessary, practiced outside containment to minimize personnel time in containment.

(f) Test and replacement equipment should be checked carefully for operability prior to entry into containment.

5.3 Precautions

High voltages may be encountered during procedures specified in this Section; therefore, care must be taken to protect both personnel and equipment from shock hazards and electrostatic shock damage. Accelerometer signal leads or cables attached to accelerometers should be shunted to ground before connection to other equipment. Personnel preparing specific procedures based on this Part shall ensure that voltages produced by impedance-measuring devices will not damage the components under test.

5.4 Calibration

5.4.1 Initial Installation. Initial calibration of the LPM electronics shall be performed prior to baseline testing.

(a) Control Cabinet Electronics. Perform vendor-recommended calibration.

(b) Charge Converter/Preamplifier. Prior to installation, verify the conversion ratio (mV/pC) and determine the frequency response (over the range of 5 Hz to 20 kHz) using a simulated charge input. The block diagram is presented in Fig. 10.

(c) Sensor Cable. Measure the open-circuit resistance and capacitance of the sensor cable (consult the cable vendor for the correct procedure).

(d) Sensor

(1) Verify sensor frequency response, amplitude linearity, and sensitivity. Test instrument system accuracy shall be ±5%. Sensor excitation may consist of either a continuous frequency sweep at a single acceleration value or discrete frequencies at a minimum of seven points distributed over the sensor response range. Sensitivity shall be verified at one or more of the manufacturer's calibration frequencies (typically 100 Hz, 5 kHz, or 10 kHz). Amplitude linearity shall be determined by measuring at 0.1 g and 10 g at approximately 5 kHz. It is recommended that the method used be in accordance with ANSI S2.11-1969.

(2) Measure the resistance and capacitance of the sensor. To prevent component damage, consult the sensor vendor for the correct procedure.

(3) If an accelerometer is dropped or physically damaged, do not use it until it is retested by the continuous sweep method and verified to be undamaged.

(4) After the sensor and cabling to the charge converter/preamplifier have been installed, measure the resistance and capacitance of the sensor/sensor cable combination at the input to the charge converter.

(5) Once installed, never remove the sensor except for replacement. Sensors shall not be replaced routinely.

(e) Field Cabling. With the field cabling disconnected at the control cabinet and at the remote charge converter/preamplifier, measure the cable properties (typical for twisted, shielded-pair cable) shown in Fig. 11.

Do not use more than 50 V in determining resistance. Use either a bridge-type instrument or capacitance meter verified to be accurate for measuring capacitance in long cables.

5.4.2 Replacement. Perform the appropriate preinstallation and impact tests for any repaired or replaced component. The impact location(s) shall be consistent with the requirements set forth in para. 5.5.3 of this Part. A single mass in the 3 lb to 5 lb (1.4 kg to 2.3 kg) range as specified in para. 5.5.4 is recommended.

5.5 Baseline Impact Testing

5.5.1 General. Data acquired in the baseline test program are used in the analysis and diagnosis of anomalous noise in the reactor system. The baseline test program should be implemented prior to initial LPM operation, and is required after changeout of any component upon which an LPM sensor is mounted.

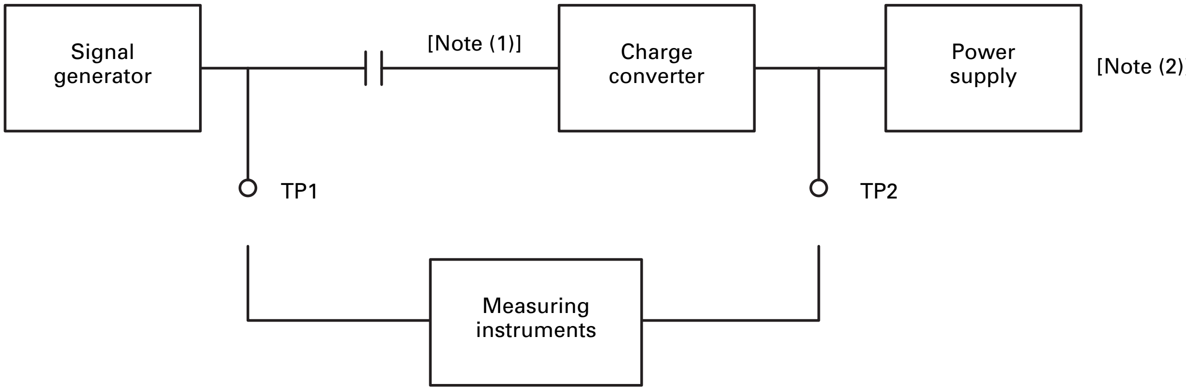
The purpose of impact testing is

(a) to determine system sensitivity to impacts of known energy or force at known locations

(b) to characterize transducer response to impacts from objects of different masses at known locations

(c) to verify the capability to discriminate primary- versus secondary-side impacts in steam generators and

Fig. 10 Block Diagram for Charge Converter Calibration Tests



NOTES:
(1) 1000 pF typical; consult charge converter vendor for specifics.
(2) Use LPM signal conditioner if possible.

the capability to determine the approximate impact location in the reactor coolant system

The impact amplitude shall be calculated using the test weight mass and distance through which it falls if a pendulum/drop method is used. The impact amplitude can be measured electronically when using an instrumented hammer as the stimulus.

5.5.2 Plant Conditions. Impact testing should be performed during cold shutdown; calibration at higher temperatures is discouraged for safety reasons. Reactor coolant system water levels should be as close to normal operating levels as possible.

5.5.3 Impact Locations. At least two impact test locations shall be selected and documented for each natural collection region and the secondary side of each steam generator. The impact locations shall not be within 3 ft (0.91 m) of any sensor. Since one impact point in each collection region (except the reactor vessel bottom) is intended to be used for periodic impact testing, ease of access shall be considered.

5.5.4 Test Weights/Hammer Masses. A range of test weights should be used to define channel response over the monitored frequency band (refer to Fig. 3). Recommended weights for the ball or hammer are 0.5 lb to 1.0 lb, 3 lb to 5 lb, and 10 lb to 20 lb (0.23 kg to 0.45 kg, 1.4 kg to 2.3 kg, and 4.5 kg to 9.0 kg, respectively). For each test weight at least three impact amplitudes should be used. To prevent or minimize surface marring, the test weights and hammer tips should be fabricated from metal slightly softer than the surface to be struck.

5.5.5 Impact Test Analysis. Impact test data shall be reduced and analyzed at the completion of the test data acquisition program. The purpose of this analysis is to determine the response to known metallic impacts and to provide reduced reference data for use in diagnostics.

(a) Normalized response outputs shall be provided in one or more of the following frequency domain formats:

(1) force hammer: frequency response function displaying the ratio of acceleration (response) to force (input).

(2) ball: auto spectral plots of each sensor response.

A digital Fourier transform method shall be used to calculate the spectrum. Appropriate transform block lengths or an exponential weighting function shall be used to ensure that the amplitude of the signal at the end of the transform data block is less than 10% of the peak amplitude.

The analysis results should be in engineering units. The preferred engineering units for spectral plots are g^2/Hz or g/Hz$^{1/2}$ and for the frequency response function are g/lb. The preferred units for PSD are g^2/Hz. Some PSD systems may also use units of g/(Hz)$^{1/2}$.

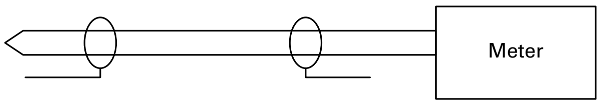
(b) The delay times between the wave arrival at different sensor locations should be measured for all channels. The measurements should be relative either to the sensor closest to the impact point or to the instrumented hammer.

(c) The primary signal frequency content should be identified for impacts generated by each mass, and sensor mounted and crystal resonances should be identified for each sensor. The analysis displays shall extend to less than 10 Hz.

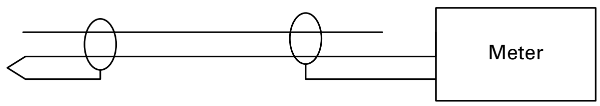
Each LPM channel peak response shall be measured for every impact. The corresponding peak input level shall also be documented for each impact. Peak amplitudes for multiple impacts at a single test condition should be averaged. The average, high, and low values for each sensor and test condition should be documented.

Prior to performing time domain analysis, low-pass filter the signal to reduce the effect of the sensor resonances. Time domain plots should be displayed with

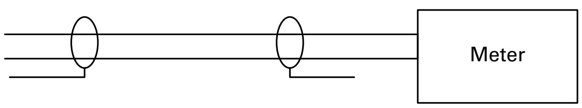
Fig. 11 Cable Properties (Typical for Twisted-Shielded Pair Cable)



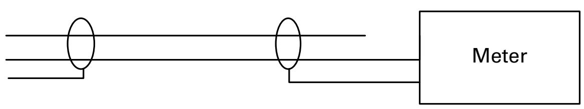
(a) Signal Pair Loop Resistance (Typical <20 ohm)



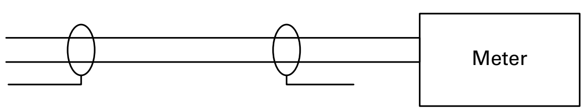
(b) Conductor-to-Shield Loop Resistance (Typical <20 ohm)



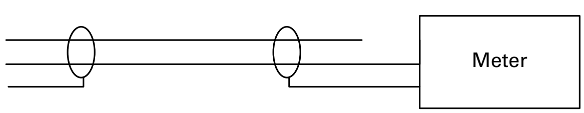
(c) Conductor-to-Conductor Resistance (Typical >200 ohm)



(d) Conductor-to-Shield Resistance (Typical >200 ohm)



(e) Conductor-to-Conductor Capacitance (Derive from Vendor Data)



(f) Conductor-to-Shield Capacitance (Derive from Vendor Data)

time on the horizontal axis and signal magnitude on the vertical axis. The signal magnitude shall be plotted in g units, although units of volts are acceptable if the waveform analyzer cannot perform engineering unit conversions (in this case, the relationship between voltage and acceleration shall be noted on the plot).

5.6 Initial LPM Setpoints

At the onset of initial RCS flow and as heatup progresses, verify that the LPM channels are operable. This may be done by measurement and trending of RMS values and identification (and documentation) of major structural resonance characteristics.

In the event of prolonged reactor startup or reduced power operation, the LPM setpoints should be optimized as conditions warrant. Within 2 weeks after reaching full-power operation, a review of the major reactor coolant system background noise should be complete. At that time, LPM systems having adjustable bandpass filters shall be adjusted for optimum noise rejection in each channel. The low-pass break frequency should not be less than 8 kHz nor the high-pass greater than 2 kHz, except as necessary to reject interfering background noises having an adverse effect on sensitivity or false alarm rates; but, in no case shall the bandpass be reduced to less than 5 kHz. Systems with fixed high- and low-pass filters should use 1 kHz and 10 kHz as the respective high- and low-pass break frequencies. The final filter settings shall be included in the system documentation package.

Both absolute and variable (floating) threshold detector alert levels shall be set initially to three times the long-term, band-limited background noise level at power operation to 1 g or to the manufacturer's recommendation. Individual channel threshold levels (setpoints) shall be adjusted after reaching power operation so that the system false alarm rate caused by Type 2 false alarms is approximately one event every 2 weeks. After establishing the rate, verify that the threshold levels necessary to achieve the rate are not so high as to compromise sensitivity to potentially damaging loose parts. For floating systems, this may be accomplished by ensuring that the effective threshold setpoint (background level multiplied by the floating threshold ratio) does not exceed 1 g. If the setpoint exceeds 1 g, the system installation and/or the reason for excessive variation in the background noise should be investigated and corrective action taken.

5.7 Heat-Up and Cool-Down Monitoring

During plant heat-up and cool-down, RCS noises different from those during normal operation will be present. It is also a period of time during which the probability of a loose part is greater than normal. Therefore, during plant transient operation it is recommended that the following actions be considered:

(a) Audibly monitor noises during RCP starts and stops.

(b) Record data during the first RCP start, first shutdown, and last shutdown of a cycle.

(c) Monitor each shift in accordance with para. 5.8.2.

5.8 Periodic Monitoring and Testing

Periodic monitoring of the RCS is an integral part of an effective loose part program; periodic testing of an LPM provides the basis for determining system operability. Both shall be performed on a shift, week, quarter, and fuel cycle basis. System parameters measured or observed during each test shall be documented on a data sheet and included in the system documentation. If during periodic testing the LPM or any LPM channel is determined or suspected to be inoperable, corrective action shall be initiated.

5.8.1 Startup. Background from each sensor shall be recorded during initial startup of the system using installed system recording capability. The data shall be maintained in a retrievable format (e.g., disk, magnetic tape). It is recommended that monitoring and recording be done both during hot standby and within 100 hr of reaching full-power operation.

5.8.2 Each Shift. With initiation of reactor coolant flow, perform the following:

(a) Verify that the LPM power is on.

(b) Verify that the LPM is in a ready condition (e.g., recorder autostart enabled and inhibits off).

(c) Monitor sound from all active sensors. Each channel should be monitored for at least 30 sec. Noise considered to be anomalous should be documented and evaluated.

5.8.3 Each Week. With the reactor in hot standby or power operation, perform the following:

(a) Identify and document the channels that are being actively monitored.

(b) Monitor sound from all active sensors. Each channel should be monitored for approximately 30 sec. Noise considered to be anomalous should be documented and evaluated.

(c) Document the status of user controllable set-points (e.g., gains and filters) and verify that the switch settings are as intended.

(d) Measure and document the background level of each active channel using front panel test points or meters, if provided.

(e) Perform vendor recommended self-test of the LPM automatic alert and alarm circuitry.

5.8.4 Each Quarter. With the reactor in hot standby or power operation and with all reactor coolant pumps running, do the following.

(a) Perform the weekly test for all channels, both active and passive (if present).

(b) Record background from each sensor shall be recorded for trend analysis as specified in para. 5.8.5. The data should be maintained in a retrievable format (e.g., disk, magnetic tape).

(c) Compare spectra from each channel with data from the two preceding quarterly functional tests. The comparison should include spectral response in the range of the RCP blade-passing frequency, known structural resonances, broad-band flow noise, and accelerometer-mounted resonance.

(d) Verify the performance of the installed LPM recorder(s).

(e) Measure and document the voltage or current supplied to each remote charge converter. Adjust the voltage or current supply if recommended by the vendor and document any changes made.

5.8.5 Each Fuel Cycle

(a) At each refueling outage, any degradation of LPM components shall be evaluated and documented. The evaluation should be based on the following:

(1) trends in charge converter supply voltage or current

(2) variations in the quarterly spectral data that may be indicative of change in the overall response of a channel

(3) the performance of vendor-recommended calibration of LPM control cabinet electronics

Changes in spectral characteristics or trend information shall be evaluated and documented. Unexplained deviations shall be formally evaluated and corrective action taken if appropriate.

(b) As an outage item to be performed immediately prior to heatup, validate the operability of each channel by performing an impact test(s). The impact location(s) shall be consistent with the requirements set forth in para. 5.5.3. A single mass in the 3 lb to 5 lb (1.4 kg to 2.3 kg) range as specified in para. 5.5.4 is recommended.

5.9 Alarm Response and Diagnostics

5.9.1 General. Actions should be taken to determine if the alarm has been caused by an actual loose part and what the damage potential may be. Data in the form of plots, graphs, and amplitudes should be labeled and scaled in units consistent with those in para. 5.5.5.

5.9.2 Alarm Response. Plant procedures shall require operator response to all LPM alarms. Initial alarm response shall include the following:

(a) Verify that automatic data recording was initiated.

(b) Identify and document the unit/channel(s) alarming.

(c) Reset the LPM.

(d) Listen to all channels.

(e) If the alarm cannot be reset or recurs within 5 min, notify the shift supervisor.

(f) Log the signal conditioner gain or range for the signals recorded if not provided automatically by the system.

(g) Note the time of day, the plant condition, and any significant plant operating changes that occurred before the alarm.

5.9.3 Diagnostics. LPM alarms that are indicative of metallic impacting shall be further evaluated by appropriate personnel. The objectives of diagnostic evaluation are to

(a) verify LPM channel operability.

(b) estimate the location of the metallic impact based on consideration of delay time, amplitude, and wave shape.

(c) estimate impact energy based on initial impact test data.

(d) estimate impact mass based on the baseline test data and measured signal properties including amplitude and frequency content.

(e) review plant process data for anomalous behavior.

(f) review diagnostic results with plant operation personnel.

5.9.4 Background Changes and Setpoint Adjustments. Alarm diagnostics may indicate a change in plant background characteristics rather than the presence of a loose part. When this process occurs, the LPM alarm rate may in time increase to an unacceptable level. Adjustments are permitted, but the threshold shall not be increased without investigating the reason for the change in the background. Any change in setpoints shall be entered in the system documentation.

6 DOCUMENTATION

The LPM operator shall maintain system documentation containing accurate and complete information pertinent to the system, its calibration, and any other information that would affect measurements, judgments, and calculations made during data analysis. The documentation shall also include the information necessary to quickly locate a particular sensor, charge converter, or cable junction for maintenance, calibration, or diagnostics. As a minimum, the following shall be included:

(a) Vendor manuals and calibration data.

(b) As-built field drawings. Electrical drawings shall include cabling and conduit drawings detailing penetrations, conduit routing, and junction box locations. Mechanical drawings shall include sensor locations, sensor mount fabrication drawings, and charge converter/preamplifier locations.

(c) Installed (in-containment) component identification to include the device model and serial numbers and types and lengths of cable used between the accelerometer and the charge converter.

(d) Complete photographic documentation of the sensor and charge converter installation (ALARA and safety considerations may preclude this requirement in some existing systems).

(e) The results of and procedures for all tests required by this document.

PART 12
NONMANDATORY APPENDIX A
References

ANSI S2.10-1971, American National Standard Medthods for Analysis and Presentation of Shock and Vibration Data

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Regulatory Guide 1.133, Loose Part Detection Program for the Primary System of Light-Water Cooled Reactors, Revision 1, 1981

NUREG/CR-4577, Loose Part Monitoring Programs and Recent Operational Experience in Selected U. S. and Western European Commercial Nuclear Power Stations, R. C. Kryter, 1984

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PART 16

Figure

Nonmandatory Appendices

PART 16
Performance Testing and Inspection of Diesel Drive Assemblies in LWR Power Plants

1 INTRODUCTION

1.1 Scope

This Part establishes the requirements for inservice testing and inspection to assess the operational readiness of certain diesel drive assemblies used in light-water reactor (LWR) power plants. The diesel drive assemblies covered are those 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. This Part establishes inspection requirements, parameters to be measured and evaluated, and record requirements.

1.2 Purpose

The purpose of this Part is to provide the principal inservice tests and monitoring requirements for diesel drives to confirm that they meet their functional requirements as part of the overall nuclear power plant design. This Part provides methods, intervals, and record requirements for long-term diesel drive trend analysis and evaluation. The inservice test requirements provide the owner/operator guidance for establishing an effective inservice test and monitoring program to ensure diesel drive system reliability is retained throughout the life of the plant.

The owner/operator should maintain the diesel engine and the associated driven equipment in accordance with the recommended periodic maintenance of the manufacturer or as developed by the respective diesel engine owners group.

1.3 Risk-Informed Analysis

The primary skid-mounted diesel drive in the nuclear power plant is the emergency power diesel generator system. It has been demonstrated in various probabilistic risk assessment (PRA) models that the diesel generator system should be categorized as high safety significant component (HSSC) in accordance with ASME O & M Code Case OMN-3.[1]

[1] ASME O & M Code Case OMN-3 provides the requirements for Safety Significance categorization of Components Using Risk Insights for Inservice Testing of LWPR Power Plants.

1.4 Subsystems Included in This Part

Figure 1 provides the simplified boundary for the diesel engine and associated subsystems covered by this Part. Since there are varieties of diesel makes, sizes, applications, etc., each owner/operator must make the final designation of the applicable diesel drive boundary. This Part includes the driven equipment that operates as a result of work or power developed by the engine as the prime mover, for example, an electrical generator or fire pump. Since the engine cannot be tested independently of the driven equipment, the owner/operator must consider the effects of inservice testing on the driver equipment (the diesel engine and its subsystems).

Typical principal equipment for associated diesel drive subsystems, as well as the driven equipment identified in Fig. 1,[2] are listed below.

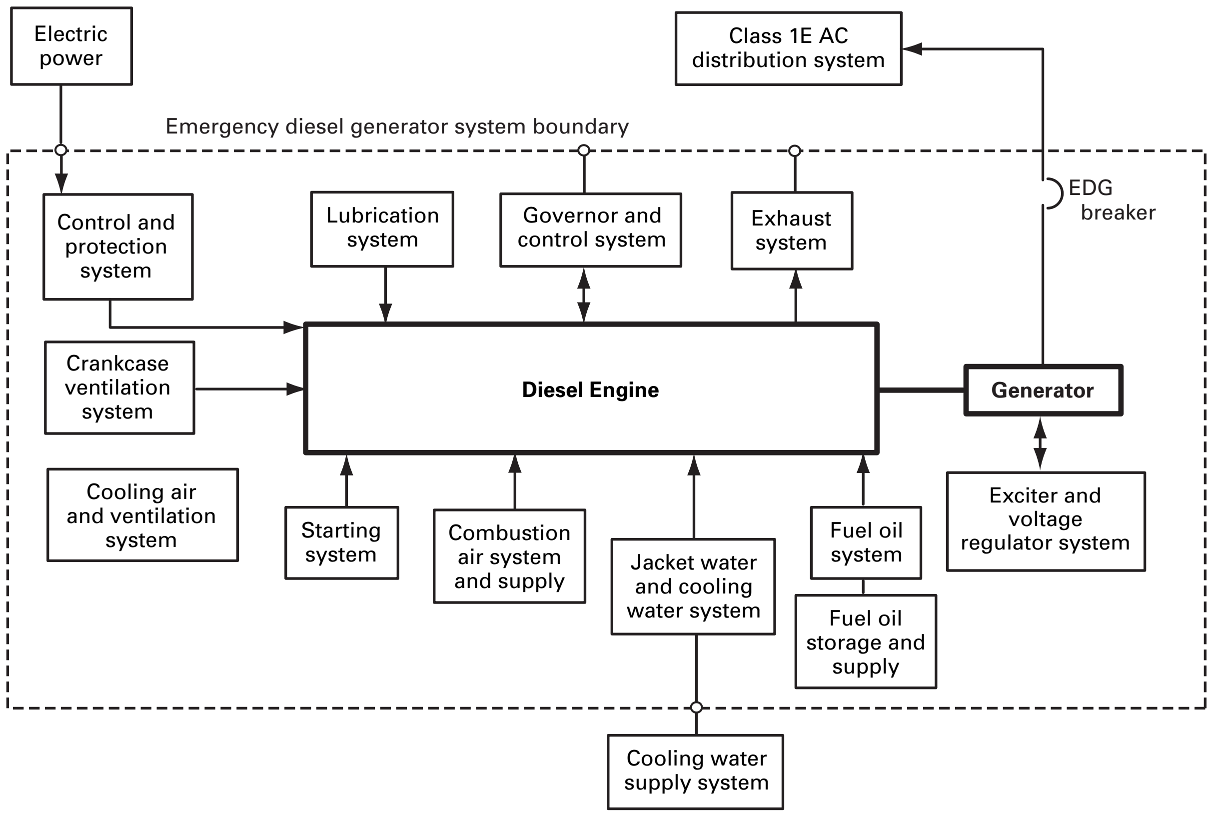
1.4.1 Lubrication Subsystem. Equipment includes (where applicable) the following:

(a) lube oil sump and makeup tank
(b) suction strainers and foot valves
(c) discharge strainers
(d) filters
(e) transfer valves for duplex filter and strainer arrangements
(f) pressure-regulating, relief, check, and thermostatic valves
(g) standby heaters and thermostat
(h) engine-driven lube oil pumps
(i) circulating (primary or backup) and prelube/post-lube pumps
(j) all piping, tubing, and associated components
(k) lube oil heat exchanger
(l) instrumentation and controls
(m) flexible hoses

1.4.2 Jacket Water and Intercooler Subsystem. Equipment includes (where applicable) the following:

[2] Figure 1 is a system boundary diagram that shows the components of the diesel system. This is similar to the system boundary identified by USNRC Regulatory Guide 1.9, Revision 3, Selection, Design, Qualification, and Testing of Emergency Diesel Generator Units Used as Class 1E Onsite Electric Power Systems at Nuclear Power Plants. Even though some of these components may not be physically located on the diesel skid, these components' design purpose of solely supporting the diesel qualify them as skid-mounted equipment.

Fig. 1 Boundary and Support Systems of Emergency Diesel Generator Systems



(a) jacket water heat exchanger
(b) intercooler systems
(c) radiators and associated fan(s)
(d) governor oil heat exchanger
(e) standby heater and associated thermostat
(f) keep-warm water pump
(g) jacket water and intercooler pumps (primary or standby)
(h) thermostatic valves and check valves
(i) standpipes and overflow, pressure cap, level indicators, and expansion tanks
(j) piping, tubing, and associated components
(k) instrumentation and controls
(l) flexible hoses

1.4.3 Starting Subsystem. Equipment includes (where applicable) the following:
(a) batteries/charging systems
(b) electric/pneumatic start motors
(c) air compressors (safety related only)
(d) air receivers; relief, check, and air-start solenoid valves; and piping, tubing, and associated components
(e) pressure-reducing valves, shuttle valves, and pressure regulators
(f) air dryers, strainers, filters, check valves, compressor intercoolers and aftercoolers, and air dryer associated components
(g) air start distributors and associated air injection valves
(h) instrumentation and controls
(i) flexible hoses

1.4.4 Combustion Air Intake Subsystem. Equipment includes (where applicable) the following:
(a) intake air filter
(b) intake air silencer
(c) intake air manifold and all piping, tubing, and associated components
(d) mechanical blowers, superchargers, and scavenging pumps
(e) turbocharger (compressor)
(f) intercooler
(g) instrumentation and controls
(h) turbo boost system (nozzles, hoses, solenoid valves, air receiver, and compressor)

1.4.5 Exhaust Subsystem. Equipment includes (where applicable) the following:
(a) turbocharger (turbine)
(b) exhaust silencer and spark arrestor
(c) exhaust relief valve and stack
(d) exhaust manifold, piping, connectors, bellows, and joints
(e) instrumentation and controls

1.4.6 Fuel Oil Subsystem. Equipment includes (where applicable) the following:

(a) fuel oil storage tank(s)
(b) fuel oil transfer pump(s), motor(s), and automatic transfer valve(s)
(c) day tank(s)
(d) strainers, filters, and transfer valves
(e) booster pump(s) and associated drive belt(s)
(f) pressure-regulating, relief, check, and isolation valves
(g) fuel oil headers, supply and return
(h) fuel injection pumps, spray nozzles, injectors, and high-pressure injection tubing
(i) fuel control and shutdown system
(j) piping, tubing, and associated components
(k) instrumentation and controls
(l) flexible hoses

1.4.7 Crankcase Ventilation Subsystem. Equipment includes (where applicable) the following:

(a) vent pipe
(b) relief doors and valves
(c) crankcase vent fan, eductor, and pump, including oil mist separator and oil return line
(d) crankcase and sump vent system
(e) piping, tubing, and associated components
(f) instrumentation and controls
(g) flexible hoses

1.4.8 Governor and Control Subsystem. Equipment includes (where applicable) the following:

(a) mechanical-hydraulic governor including associated linkages to fuel racks, hydraulic fluid, piping, tubing, and associated components
(b) pneumatic, hydraulic, or electric governor booster
(c) electric governor, speed sensor, and electromechanical interface
(d) engine fuel pump control linkage
(e) overspeed trip
(f) instrumentation and controls

1.4.9 Generator Subsystem. Equipment includes (where applicable) the following:

(a) coupling to diesel engine
(b) generator (including strip heaters)
(c) protective shutdown system
(d) instrumentation and controls

1.4.10 Pump (Fire Pump, Auxiliary Feed Pump). Equipment includes (where applicable) the following:

(a) coupling(s) within the drive train
(b) gearbox drive
(c) pumps
(d) instrumentation and controls

1.4.11 Ventilation System and Cooling Subsystem. Equipment includes (where applicable) the following:

(a) filters
(b) fans and motors
(c) vents, dampers, actuators, louvers, and ducts
(d) instrumentation and controls

1.4.12 Exciter and Voltage Regulator Subsystem. Equipment includes (where applicable) the following:

(a) generator exciter
(b) voltage regulator system
(c) generator/exciter electrical connections
(d) other instrumentation and controls

1.4.13 Control and Protection Subsystem. Equipment includes (where applicable) the following:

(a) devices for automatic and manual starting
(b) devices for load shedding
(c) synchronizing equipment
(d) fast transfer switches
(e) DC power supplies dedicated to the diesel engine

1.4.14 Diesel Generator Output Breaker. Equipment includes (where applicable) the following:

(a) output breaker and associated relaying
(b) control switches and auxiliary contact

1.5 Definitions

These definitions are provided to ensure a uniform understanding of selected terms used in this Part. Several additional terms, often not well defined elsewhere, are included to help provide uniformity and clarity to the nuclear power industry's use of these terms as they relate to the testing and maintenance of diesel drives.

abnormal condition: an engine condition defined by situations and applications as outside acceptable parameters, as defined by the Manufacturer and users.

bar engine over: the act of rotating the engine slowly for maintenance or inspection purposes.

barring device: an arrangement that provides for the slow rotation of the engine.

blowdown: the act of blowing moisture and/or oil accumulation from the engine cylinders through opened cylinder petcocks. Also applies to blowing moisture from the starting air receivers and air system.

continuous load/rating: the power output capability that the diesel drive unit can operate for a period of time, as specified by the manufacturer, with only scheduled outages for maintenance.

cranking: the act of using external power sources (electricity or air pressure) to cause the engine's crankshaft to rotate without the engine sustaining operation with its own combustion and before the engine provides useful work.

diesel drives: the assembly or aggregate of assemblies of one or more single or multiple diesel engines used as prime movers.

driven equipment: the equipment that operates as a result of work or power developed by the engine as prime mover, regardless of the receiving equipment's use. For example, an engine-driven pump that is using the engine's work to serve a plant need, such as a generator or fire pump.

equilibrium temperature: the condition at which the diesel engine jacket water and lube oil temperatures are both within ± 10°F (5.5°C) of normal operating temperatures established by the engine manufacturer.

excessive vibration: a condition during operation where an engine, or its component parts, vibrates more than is generally accepted and where a condition exists that is exceeding the acceptance criteria.

keep-warm system: system or systems that maintain jacket water, fuel oil, and/or lube oil temperatures at warm standby values recommended by the engine manufacturer.

major maintenance: the maintenance that return the diesel engine to operating status following an abnormal event. Examples of such an event would be crank case explosion and piston rod ejection. Such major maintenance effort would be similar to the DR/QR of the TDI engines, as being anything that requires the engine to be taken down to the frame and completely rebuilt.

maximum available load: the amount of load that is practical for applying to the diesel engine for testing purposes on an isolated bus. The maximum available load may be at or below the continuous load rating of the diesel.

standby condition: the condition at which the diesel engine jacket water, fuel oil, and lube oil systems are maintained by the keep-warm system within the range of temperatures established by the engine manufacturer.

2 POST-MAJOR MAINTENANCE CHECK

The owner/operator shall perform an initial check of the engine's systems, subsystems, and components to ensure that the overall unit will operate as designed. These checks include flushes, hydrostatic tests (if required following major repair/replacement activities) of fluid systems, visual checks, functional tests of support components and systems, and those additional tests as recommended by the manufacturer.

3 TESTING

3.1 Post-Major Maintenance Testing

The owner/operator shall perform testing for post-major maintenance for existing engines that are above and beyond those normal maintenance-related tests specified by the diesel engine manufacturer. These tests shall be performed as appropriate.[3] Note that the reliability tests for newly installed diesel generator sets described in IEEE 387-1995, Section 7.3 do not apply since new unit reliability will have been established during initial type qualification testing. Appendix A lists the checks and data that should be considered for engines that have had major maintenance performed.

3.2 Periodic Tests

Performance of periodic diesel drive tests and monitoring operating parameters provides the owner/operator with an immediate determination of the engine performance and material condition. The owner/operator shall perform periodic tests; the type and frequency shall be in accordance with the respective plant Technical Specifications or IEEE 387-1995, Section 7.4, Periodic Testing. Note also that USNRC Regulatory Guide 1.9, Revision 3, endorses testing guidelines set forth in IEEE 387. The periodic testing frequencies identified in this Part are not requirements. They are identified as a matter of convenience for the monitoring of operating parameters and to coincide with plant testing programs.

3.3 Diesel Engine Analysis

(a) Diesel engine analysis is an effective tool in support of an inservice testing program because

(1) It provides the technical basis for developing a performance-based maintenance program.

(2) It detects certain degraded engine material condition or engine performance.

(3) It provides the basis for engine tuning adjustments to improve power balance.

Diesel engine analysis involves recording specific engine operating parameters during normal operation. These engine operating parameters include engine cylinder pressure (both compressions and firing pressure), vibration, and ultrasonic readings. All three readings are recorded as a function of crankshaft position for each cylinder, fuel injection pump, and injector. Cylinder pressure is analyzed for specific quantitative values (peak pressure, firing pressure angle, cycle variation, etc.) and profiles during operation. Certain known events (intake and exhaust valve closing and opening, fuel injection) are reviewed to verify they occur at the proper timing. Engine analysis is also used to balance and tune the engine to ensure the power from each cylinder is nearly equivalent.

(b) Benefits realized from diesel engine analysis include

(1) Reduced Maintenance. Users of diesel engine analysis experience reductions in maintenance costs by

[3] This Part recommends the owner/operator to follow the tests as specified in IEEE STD 387-1995, IEEE Standard Criteria for Diesel Generator Units Applied as Standby Power Supplies for Nuclear Power Generating Stations, Section 7.3 Preoperational Testing.

eliminating periodic engine tear downs and part replacements. This is achieved by performing specific maintenance and/or repairs required on selected components identified by engine analysis rather than periodically disassembling the entire machine and replacing components unnecessarily.

(2) Increased Reliability. Long-term reliability increases by reducing failures of newly installed engine components and reducing maintenance-induced failures.

(3) Increased Availability. Reduced time required for maintenance activities permits the plant to increase diesel engine availability.

(4) Reduced Fuel Consumption. As much as 3% to 5% fuel savings can be realized by optimizing the cylinder power balance and engine tuning.

4 INSERVICE TESTING OF COMPONENTS

The recommended, periodic, inservice testing of the diesel drive components that were identified in para. 1.4 are described here. Because the diesel drive and supporting components are operated periodically during normal engine operational surveillance testing, it is recommended that the necessary performance data be monitored and trended to eliminate additional testing for individual components. The environment that exists during the periodic engine operation is indicative of engine room conditions during extended engine operation. These conditions ensure that adequate demands are being placed on the equipment, so that operating data/information gathered is a valid indicator of component performance and long-term degradation of the diesel drive can be identified and corrected. Given below are the diesel drive subsystem components, the performance test (verifies function) and its frequency, and the parameters to be monitored as applicable to station requirement/design for the diesel system.

4.1 Lubrication Subsystem

(a) Lube oil sump and makeup tank

(1) Daily: check main engine and turbo lube oil sump levels.

(2) Monthly during engine operation: check main engine and turbo lube oil levels to identify degradation prior to failure.

(3) Quarterly: perform lube oil analysis.

(b) Suction strainers and foot valves

(1) Monthly during engine operation: check main engine and turbo lube oil pressure data as well as differential pressure across the strainers to identify degradation prior to failure.

(c) Discharge strainers

(1) Monthly during engine operation: check main engine and turbo lube oil pressure data as well as differential pressure across the strainers to identify degradation prior to failure.

(d) Filters

(1) Monthly during engine operation: check main engine and turbo lube oil pressure data as well as differential pressure across the filters to identify degradation prior to failure.

(e) Transfer valves for duplex filter and strainer arrangements

(1) Monthly during engine operation: check for external leaks as part of overall engine leak inspections (monitor during engine operation when system is pressurized).

(f) Pressure-regulating, relief, and thermostatic valves

(1) Monthly during engine operation: check main lube oil pressure and temperature data to identify degradation of these components prior to degradation of engine performance.

(g) Standby heater and its associated thermostat

(1) Daily: check lube oil standby temperature to identify degradation of these components prior to degradation of engine performance.

(h) Pumps including engine driven, circulating (primary or backup)

(1) Monthly during engine operation: check main lube oil pressure to identify degradation of the pump's performance.

(i) Circulating (primary or backup) and prelube/postlube pumps

(1) Daily: check standby and operating temperatures and pressures to identify degradation of the pump's performance.

(j) All piping, tubing, and associated components

(1) Daily: check for external leaks as part of overall engine walkdown.

(2) Monthly during engine operation: check for external leaks, as part of overall engine leak check, when system is pressurized.

(k) Lube oil heat exchanger

(1) Monthly during engine operation: check and trend heat exchanger lube oil inlet and outlet temperatures to identify degradation within the heat exchanger.

(l) Instrumentation and controls

(1) Daily: verify engine parameters are within normal standby ranges.

(2) Monthly during engine operation: verify engine operating parameters are within normal ranges.

(m) Flexible hoses

(1) Monthly during engine operation: visually check hoses for signs of degradation such as age-induced cracking or excessive wear around end fittings.

4.2 Jacket Water and Intercooler Subsystem

(a) Jacket water heat exchanger

(1) Monthly during engine operation: check and trend service water flow rate, jacket water, and service

water temperatures to identify degradation within the heat exchanger.

(b) Intercooler systems

(1) Monthly during engine operation: monitor exhaust temperatures and power output of the engine, as well as intake manifold temperature, to identify loss of system performance.

(c) Radiators and associated fan

(1) Monthly during engine operation: visually check material conditions and monitor and trend temperatures across the radiator to identify loss of system performance.

(2) Semiannually: perform vibration check of the fan.

(d) Governor oil heat exchanger

(1) Monthly during engine operation: check proper governor control and operation to confirm satisfactory condition of the heat exchanger.

(e) Standby heater and its associated thermostat

(1) Daily: check lube oil standby temperature to identify degradation of these components prior to engine degradation.

(f) Keep-warm water pump

(1) Daily: check proper standby jacket water temperatures and pressures to confirm proper operation of this pump.

(g) Jacket water and intercooler pumps

(1) Monthly during engine operation: check and trend operating temperatures and pressures to identify degradation of the pumps' performance.

(h) Thermostatic valves

(1) Monthly during engine operation: check jacket water temperature data to identify degradation of these components prior to degradation of engine performance.

(i) Standpipes and overflow, pressure cap, level indicator, and expansion tanks

(1) Daily: check proper coolant level.

(2) Quarterly: perform cooling water chemical analysis.

(j) Piping, tubing, and associated components

(1) Daily: check for external leaks as part of overall engine leak inspections.

(2) Monthly during engine operation: check for external leaks, as part of overall engine leak inspections, when system is pressurized.

(k) Instrumentation and controls

(1) Daily: verify engine parameters are within normal standby ranges.

(2) Monthly during engine operation: verify engine operating parameters are within normal ranges.

(l) Flexible hoses

(1) Monthly during engine operation: visually inspect hoses for signs of degradation such as age-induced cracking or excessive wear around end fittings.

4.3 Starting Subsystem

(a) Batteries/charging systems

(1) Monthly: check alarms and local indications to determine any degradation of these power supplies.[4]

(b) Electric/pneumatic air start motors

(1) Semiannually: record timing and trending of fast start testing to identify a degradation of the air start system being used to start the engine.

(c) Air compressors (safety-related only)

(1) Daily: check air compressor oil level.

(2) Quarterly: record compressor run times to identify any degradation of this compressor.

(d) Air receivers; relief, check, and air-start solenoid valves; and piping, tubing, and associated components/receivers, covered under ASME Code

(1) Daily: manually blow down receivers unless equipped with automatic blowdown equipment.

(e) Relief valves, covered in ASME OM Code, Appendix I

(f) Check valves, covered in ASME OM Code, Section ISTC

(g) Air-start solenoid valves

(1) Quarterly: verify lubricator operation and oil level.

(2) Semiannually: record timing and trending of fast start testing to identify a degradation of the air start system being used to start the engine.

(h) Piping, tubing, and associated components

(1) Daily: check for external leaks as part of overall engine leak checks.

(2) Monthly during engine operation: check for external leaks, as part of overall engine leak checks, when system is pressurized.

(i) Pressure-reducing and shuttle valves and regulators

(1) Semiannually: record timing and trending of fast start testing to identify a degradation of the air-start system being used to start the engine.

(j) Air dryers, strainers, filters, check valves, compressor intercoolers, and air dryer–associated components (safety-related only)

(1) Quarterly: check/clean filters as applicable.

(2) Semiannually: monitor air dewpoint temperatures and electrical current consumption during compressor and dryer operation to identify degradation of these components.

(k) Check valves (Code boundary), covered in ASME OM Code, Section ISTC, Inservice Testing of Valves in Light-Water Reactor Nuclear Power Plant

(l) Air-start distributors and associated air injection valves

[4] The owners may follow the recommendation provided by Institute of Electrical and Electronics Engineers (IEEE) 450-1995, Maintenance, Testing , and Replacement of Large Lead Storage Batteries for Generating Stations and Substations.

(1) Semiannually: record timing and trending of fast start testing to identify degradation of the air-start system being used to start the engine.

(m) Instrumentation and controls

(1) Daily: verify engine parameters are within normal standby ranges.

(2) Monthly during engine operation: verify engine parameters are within normal operating ranges.

4.4 Combustion Air Intake Subsystem

(a) Intake air filter

(1) Monthly during engine operation: monitor appropriate pressures to help identify degradation of air filters prior to degradation of engine performance.

(2) Every 18 to 24 months: check filters for degradation.

(b) Intake air silencer

(1) Monthly during engine operation: monitor appropriated pressures to identify degradation of these components prior to degradation of engine performance.

(c) Intake air manifold and all piping, tubing, and associated components

(1) Monthly during engine operation: monitor appropriated pressures to identify degradation of these components prior to degradation of engine performance.

(d) Mechanical blowers, scavenging pumps, and superchargers

(1) Monthly during engine operation: monitor appropriated pressures to identify degradation of these components prior to degradation of engine performance.

(e) Turbocharger (compressor)

(1) Monthly during engine operation: monitor appropriated pressures to identify degradation of these components prior to degradation of engine performance.

(f) Intercooler

(1) Monthly after engine operation: verify for intercooler leakage.

(2) Monthly during engine operation: monitor engine inlet temperature as well as exhaust temperatures to identify intercooler degradation prior to degradation of engine performance.

(3) Every 18 to 24 months: perform intercooler DP test.

(g) Instrumentation and controls

(1) Daily: verify engine parameters are within normal standby ranges.

(2) Monthly during engine operation: verify engine operating parameters are within normal ranges.

4.5 Exhaust Subsystem

(a) Turbocharger (turbine)

(1) Monthly during engine operation: monitor and trend turbocharger discharge temperature.

(b) Exhaust silencer and spark arrestor

(1) Every 18 to 24 months: monitor and trend exhaust back pressure and/or cylinder or turbocharger exhaust temperatures to identify degradation of the internals of these components.

(c) Exhaust relief valve and stack, covered under ASME OM Code, Appendix I, Requirements for Inservice Performance Testing of Nuclear Power Plant Pressure Relief Devices

(d) Exhaust manifold, piping, connectors, bellows, and joints

(1) Every 18 to 24 months: visually check, as part of overall engine checks of these components, to verify no cracks or excessive degradation has occurred.

(e) Instrumentation and controls

(1) Daily: verify engine parameters are within normal standby ranges.

(2) Monthly during engine operation: verify engine operating parameters are within normal ranges.

4.6 Fuel Oil Subsystem

(a) Fuel oil storage tank(s), covered under appropriate ASME Code and local and state regulations and/or API Standard[5]

(b) Fuel oil transfer pump(s), motor(s), and automatic transfer valve(s)

(1) Quarterly (if system contains a backup pump, every 18 to 24 months recommended): record day tank fill times or flow rate to identify any degradation of these components.

(c) Day tank(s), covered under appropriate ASME Code and local and state regulations and/or API Standard[5]

(d) Strainer(s), filter(s), and transfer valve(s)

(1) Monthly during engine operation: check fuel oil pressure data as well as differential pressure across the strainers and filters to identify degradation prior to failure.

(e) Booster pump(s) and associated drive belt(s)

(1) Monthly during engine operation: check fuel oil pump outlet pressure to identify degradation prior to failure. Visually inspect drive belts.

(f) Pressure-regulating, relief, check, and isolation valves

(1) Monthly during engine operation: check fuel oil pressure data to identify degradation prior to failure.

(g) Fuel oil headers, supply and return

(1) Monthly during engine operation: check for external leaks during engine operation when system is pressurized.

(h) Fuel injection pumps, spray nozzles, injectors, and high-pressure injection tubing

[5] The owners may follow the recommendations in American Petroleum Institute (API) Standard 653-1995, Tank Inspection, Repair Alteration, and Reconstruction.

(1) Monthly during engine operation: monitor and trend cylinder exhaust temperatures to identify degradation prior to failure.

(i) Fuel control and shutdown system: see para. 4.8.

(j) Piping, tubing, and associated components

(1) Daily: check for external leaks as part of overall engine leak checks.

(2) Monthly during engine operation: check for external leaks, as part of overall engine leak checks, when system is pressurized.

(k) Instrumentation and controls

(1) Daily: verify engine parameters are within normal standby ranges.

(2) Monthly during engine operation: verify engine operating parameters are within normal ranges.

4.7 Crankcase Ventilation Subsystem

(a) Vent pipe

(1) Monthly during engine operation: monitor and trend crankcase pressure (vacuum), or monitor alarms, to identify degradation of these components.

(b) Relief doors and valves

(1) Monthly during engine operation: monitor and trend crankcase pressure (vacuum), or monitor alarms, to identify degradation of these components.

(c) Crankcase vent fan and pump, including oil mist separator and oil return line

(1) Monthly during engine operation: monitor and trend crankcase pressure (vacuum), or monitor alarms, to identify degradation of these components.

(d) Crankcase and sump vent system

(1) Monthly during engine operation: monitor and trend crankcase pressure (vacuum), or monitor alarms, to identify degradation of these components.

(e) Piping, tubing, and associated components

(1) Daily: check for external leaks, as part of overall engine leak checks, when system is pressurized.

(2) Monthly during engine operation: check for external leaks, as part of overall engine leak inspections, when system is pressurized.

(f) Instrumentation and controls

(1) Daily: verify engine parameters are within normal standby ranges.

(2) Monthly during engine operation: verify engine operating parameters are within normal ranges.

4.8 Governor and Control Subsystem

(a) Mechanical hydraulic governor, including hydraulic fluid, piping, tubing, and associated components (including pneumatic, hydraulic, or electric governor booster)

(1) Daily: monitor oil level.

(2) Monthly during engine operation: verify proper response to start and loading signals to ensure proper operation of these components.

(3) Every 18 to 24 months: verify the engine's ability to accept accident scenario loads during response time testing to confirm proper operation.

(b) Electric governor, speed sensor and electromechanical interface

(1) Monthly during engine operation: verify proper response to start and loading signals to ensure proper operation of these components.

(2) Every 18 to 24 months: verify the engine's ability to accept accident scenario loads during response time testing to confirm proper operation.

(c) Engine fuel pump control linkage

(1) Monthly during engine operation: verify proper response to start and loading signals to ensure proper operation of these components.

(d) Instrumentation and controls

(1) Daily: verify engine parameters are within normal standby ranges.

(2) Monthly during engine operation: verify engine operating parameters are within normal ranges.

4.9 Generator Subsystem

(a) Coupling to diesel engine

(1) Every 18 to 24 months: perform generator bearing vibration checks and trending to verify the alignment and the coupling have not degraded.

(b) Generator

(1) Daily: visually check air cooling ports and generator bearing oil level.

(2) Monthly: verify the proper operation of the strip heater(s).

(3) Monthly during engine operation: verify the stator temperature is within normal range.

(c) Instrumentation and controls

(1) Monthly during engine operation: verify generator operating parameters are within normal ranges.

4.10 Pump (Fire Pump and Auxiliary Feed Pump)

(a) Coupling to diesel engine

(1) Every 18 to 24 months: perform generator bearing vibration checks and trending to verify the alignment and the coupling have not degraded.

(b) Pumps: testing covered under appropriate NFPA[6] or ASME Code.

4.11 Ventilation and Cooling Subsystem

(a) Fans and motor

(1) Daily: monitor diesel room temperatures within normal standby conditions.

(2) Monthly during engine operation: verify diesel room ambient air temperatures are maintained within normal operating ranges.

[6] The owners may use National Fire Protection Association Part 20-1999, Installation of Centrifugal Fire Pumps for the fire pump testing requirement.

(3) Quarterly: perform vibration checks and trending to verify these components are installed properly and have not degraded.

(c) Vents and louver

(1) Monthly during engine operation: verify diesel room ambient air temperatures are maintained within normal operating ranges.

(d) Ducts

(1) Monthly during engine operation: verify diesel room ambient air temperatures are maintained within normal operating ranges.

(e) Instrumentation and control

(1) Daily: monitor diesel room temperatures are within normal standby conditions.

(2) Monthly during engine operation: verify diesel room ambient air temperatures are maintained within normal operating ranges.

4.12 Exciter and Voltage Regulator Subsystem

(a) Generator exciter

(1) Monthly during engine operation: verify the exciter's ability to develop voltage to confirm proper operation.

(2) Every 6 months: verify the exciter's ability to excite the generator to the required voltage within the required time.

(3) Every 18 to 24 months: verify the engine's ability to accept accident scenario loads during response time testing to confirm proper operation.

(b) Voltage regulator

(1) Monthly during engine operation: verify the voltage regulator's ability to control voltage and parallel to the grid.

(2) Every 18 to 24 months: verify the voltage regulator's ability to accept accident scenario loads during response time testing to confirm proper operation. Verify the voltage regulator's ability to obtain required power factor while carrying the required loads during the endurance test.

4.13 Control and Protection Subsystem

(a) Devices for automatic and manual starting

(1) Monthly during engine operation: verify the devices' ability to start to confirm proper operation.

(2) Every 18 to 24 months: verify the devices' ability to start on automatic signals and diesel generator trips or trip bypasses operate per design.

(b) Devices for load shedding and sequencing

(1) Every 18 to 24 months: verify the devices' ability to shed and sequence loads during testing to confirm proper operation.

(c) Synchronizing equipment

(1) Monthly during engine operation: verify the equipment's ability to parallel with the grid to confirm proper operation (if load banks are used for monthly testing, verify every 18 to 24 months).

(d) Overspeed trip device

(1) Every 18 to 24 months: verify overspeed trip setpoint to confirm proper operation.

(e) DC power supplies dedicated to the diesel engine

(1) Monthly: check alarms and local indications to identify any degradation of these power supplies.

(f) Other instrumentation and control

(1) Monthly during engine operation: verify the engine for proper operation.

4.14 Diesel Generator Output Breaker

(a) Output breaker, control switches, auxiliary contacts and associated relays

(1) Monthly during engine operation: verify the output breaker's ability to parallel with the grid to confirm proper operation.

5 OTHER DIESEL DRIVE TESTING GUIDELINES

One of the primary focuses of this Part is the monitoring and trending of periodic test results to confirm diesel drive reliability. Subsequent to being placed into service at a nuclear power plant, the diesel drive shall be tested periodically to demonstrate the capability, availability, and reliability to perform its design function is acceptable. The following guidelines apply:

(a) Some of the periodic tests may be combined and not necessarily performed individually.

(b) The tests do not necessarily have to begin from standby conditions unless specified.

(c) All diesel drive protective trips and alarms should be in operation during the testing.

(d) Periodic testing of the diesel drive unit should not impair the capability of the unit to meet its functional/design requirements in the event of an actual plant emergency.

(e) All tests should be performed in accordance with the manufacturer's recommendations for reducing diesel engine wear, including the prelubing of the engine, post-test cool down, and post-test lubrication.

(f) The periodic testing should involve operation of the diesel engine for a minimum of 1 hr after the equilibrium (jacket water and lube oil) temperatures have been reached or as specified by the plant Technical Specifications.

6 ALARM AND SHUTDOWN DURING TESTS

During the testing of the diesel engine and its driven component, the unit may encounter alarmed conditions. Alarm limits (setpoints) are important, but the diesel engine/generator may still be operable when alarm conditions are encountered. Sometimes the diesel system must be allowed to continue operating to evaluate the alarm conditions. To properly support operations, the owner should establish diesel shutdown limits to ensure the engine has not exceeded limits that may cause the engine system to fail. Some example shutdown limits are as follows:

(a) minimum main lubrication oil pressure
(b) maximum lube oil temperature (out of the engine)
(c) minimum fuel oil header (discharge) pressure
(d) maximum cylinder exhaust temperature
(e) maximum engine exhaust temperature
(f) maximum jacket water temperature out of the engine
(g) maximum engine speed
(h) maximum allowable generator winding temperature
(i) crankcase vacuum pressure
(j) generator current output

Note that not all of the above example diesel engine alarm and shutdown limits apply to every diesel engine design or installation in nuclear power plants. As such, it is up to the individual plant owner and its technical specifications to apply the appropriate diesel drive alarm and shutdown limits within its operating procedures.

7 ENGINE OPERATING DATA AND RECORDS

Diesel drives at nuclear power stations may experience relatively few operating hours during their normal service life. These units must reliably respond to an emergency start signal. Good record keeping, data evaluation, and trending are essential tools to properly evaluate engine performance and maintain this type of reliability.

7.1 Data/Records

Appendix B provides a sample data sheet to collect periodic inservice test data. The user has the primary responsibility for the development of plant-specific data sheets. The user should consult the engine manufacturer for the determination of critical operating parameters for the specific diesel engine being evaluated.

7.2 Data Evaluation and Trending

Selected operating parameters should be plotted at frequent intervals during operating periods to reveal trends. Examples are given in Appendix C to illustrate typical information that can be obtained through trends. These examples illustrate effective data evaluation and trending techniques. The objective is to review and trend the performance of these parameters of engine performance against the manufacturers' accepted values.

7.3 Failure to Function (Root Cause)

An important aspect in maintaining diesel engine reliability is the determination of root causes of a diesel engine's failure to perform its design function. An inadequate assessment of the failure will likely lead to repeat failures. Therefore, it is important to know what caused the engine to fail so that proper corrective measures (both immediate and long-term) can be implemented. Maintaining complete and adequate records of failures and their root causes will enable the owner/operator to prevent malfunctions and identify degraded components listed in para. 1.4. Such records will highlight repeated component failures that degrade diesel engine performance and material condition.

PART 16
NONMANDATORY APPENDIX A
Post-Major Maintenance Test Data

See Fig. A-1 below for test data form.

Fig. A-1 Post-Major Maintenance Test Data Form

Plant ____________________ Unit ____________________

Engine No. ____________________ Engine RPM ____________________

Date ____________________

	Engine Parameter		Engine Load Percent 75	100	110
1	Load	kW or hp			
2	Ambient Air Temperature	°F (°C)			
3	Barometric Pressure	In Hg			
4	Run Duration	hr			
5	Jacket Water Temperature (IN/OUT)	°F (°C)			
6	Turbo Water Temperature (OUT)	°F (°C)			
7	Turbo Water Temperature (OUT)	°F (°C)			
8	Service Water Pressure (IN/OUT)	psig			
9	Service Water Temperature (IN/OUT)	°F (°C)			
10	Intercooler Water (IN/OUT)	°F (°C)			
11	Lube Oil Heat Exchanger Water (IN/OUT)	°F (°C)			
12	Jacket Water Heat Exchanger Water (IN/OUT)	°F (°C)			
13	Lube Oil Pump Outlet Pressure	psig			
14	Lube Oil Filter Pressure (INLET/OUTLET)	psig			
15	Lube Oil Header Pressure	psig			
16	Turbo Lube Oil Pressure (TO TURBO)	psig			
17	Rack Reading/Fuel Pressure				
18	Lube Oil Temperature (IN/OUT)	°F (°C)			
19	Exhaust Temperature Turbo (TO/FROM)	°F (°C)			
20	Combined Exhaust Temperature	°F (°C)			
21	Exhaust Back Pressure	In H_2O			
22	Air Intake Pressure	In Hg			
23	Crankcase Vacuum	In H_2O			

Turbocharger Lube Oil Brand and Type ____________________

Governor Lube Oil Brand and Type ____________________

Engine Lube Oil Brand and Type ____________________

PART 16
NONMANDATORY APPENDIX B
Functional/Inservice Test Data

See Fig. B-1 below for test data form.

Fig. B-1 Functional/Inservice Test Data Form

Plant ____________ Engine No. ____________ Engine Serial No. ____________

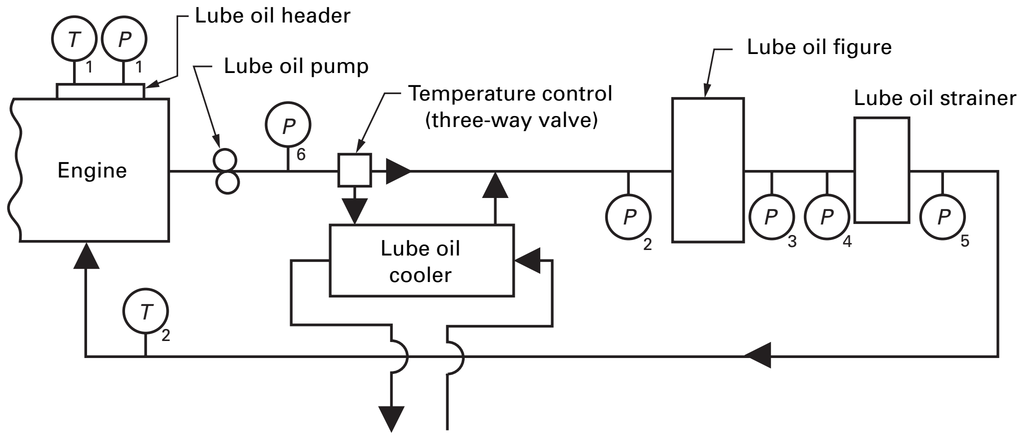
1	Engine Run Time Start/Stop	Time							
2	Ambient Air Temperature	°F (°C)							
3	Load	kW							
4	Barometric Pressure	In Hg							
5	Engine RPM								
6	Service Water Pressure (IN/OUT)	psig							
7	Service Water Temperature (IN/OUT)	°F (°C)							
8	Jacket Water Heat Exchanger Temperature (IN/OUT)	°F							
9	Jacket Water Pressure Pump Discharge Pressure	psig							
10	Jacket Water Temperature (IN)	°F (°C)							
11	Jacket Water Temperature (OUT)	°F (°C)							
12	Air Intercooler Water (IN)	°F (°C)							
13	Air Intercooler Water (OUT)	°F (°C)							
14	Lube Oil Heat Exchanger (IN/OUT)	°F (°C)							
15	Lube Oil Pressure Pump Outlet	psig							
16	Lube Oil Filter Pressure (INLET/OUTLET)	psig							
17	Lube Oil Pressure at Header	psig							
18	Fuel Oil Pressure Before/After Filter	psig							
19	Exhaust Temperature to Turbo	°F (°C)							
20	Exhaust Temperature from Turbo	°F (°C)							
21	Exhaust Pressure to Turbo	In Hg							
22	Turbo Exhaust Stack Pressure	In H_2O							
23	Pre-Turbo Air Intake Pressure	In H_2O							
24	Air Intake Manifold (Receiver) Pressure	In Hg							
25	Air Intake Manifold (Receiver) Temperature	°F (°C)							
26	Crankcase Vacuum	In H_20							
27	No. 1 Injection Pump Rack Reading								
28	Cylinder Exhaust Temperature								
29	Cylinder No. 1/No. 2	°F (°C)							
30	Cylinder No. 3/No. *n* [Note (1)]	°F (°C)							
31	Lube Oil Makeup	gal							
32	Fuel Oil Consumption	gph							

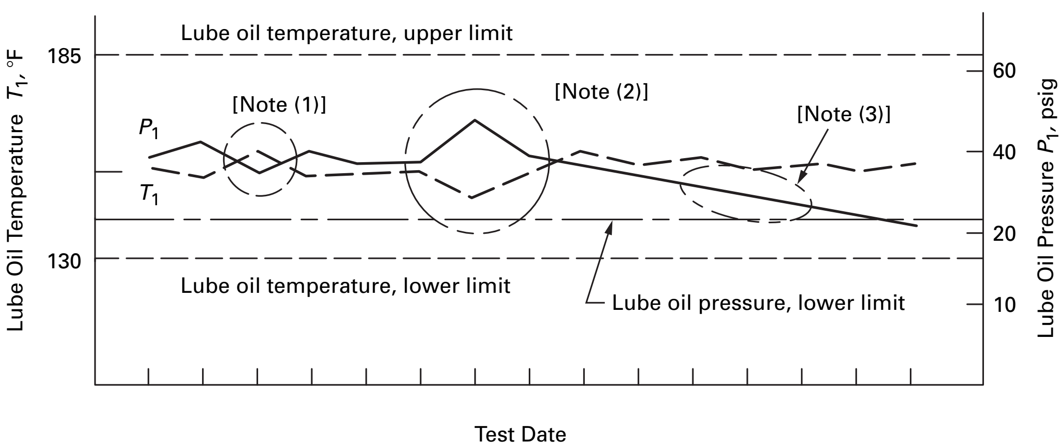
NOTE:
(1) *n* represents the total number of cylinders.

PART 16
NONMANDATORY APPENDIX C
Data Trending Examples

See Figs. C-1 through C-5 on the following pages for data trending examples.

Fig. C-1 Typical Lube Oil System





Trend Plotting — Lube Oil Temperature T_1 and Lube Oil Pressure P_1

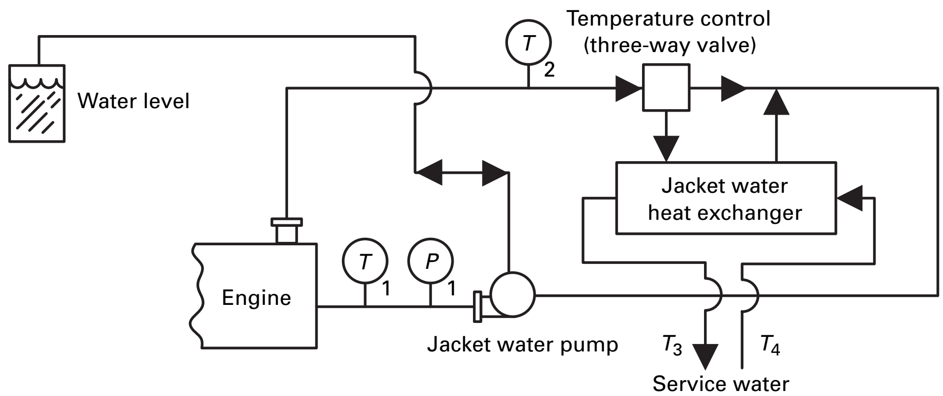
NOTES:

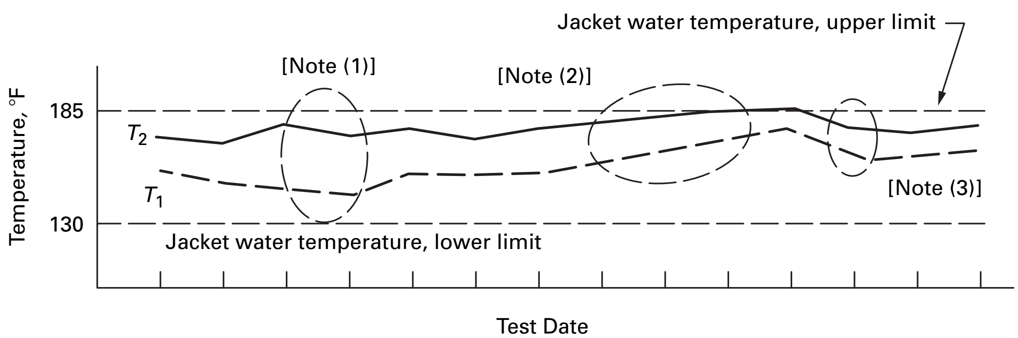
(1) Low lube oil pressure with high lube oil temperature:
- *(a)* faulty temperature control (three-way) valve
- *(b)* restricted service waterflow

(2) High lube oil pressure with low lube oil temperature: data taken prior to engine reaching equilibrium temperature.

(3) Lube oil pressure is deteriorating. Investigation should be made as to cause, although the lube oil pressure is still above the minimum. Possible causes:
- *(a)* pressure drop across lube oil filter, or strainer is high
- *(b)* lube oil pump relief valve faulty
- *(c)* bearing failures
- *(d)* lube oil system leakage
- *(e)* lube oil dilute with fuel oil

Fig. C-2 Typical Jacket Water System





Trend Plotting — Jacket Water Temperature to Engine, T_1, and From Engine, T_2

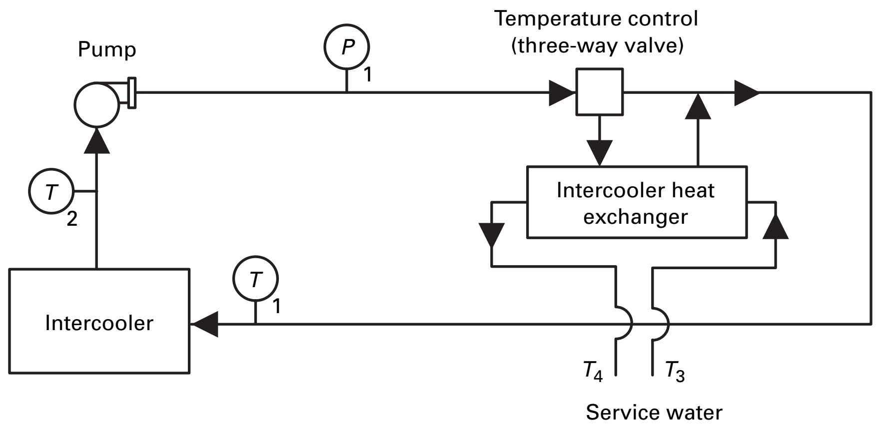
NOTES:

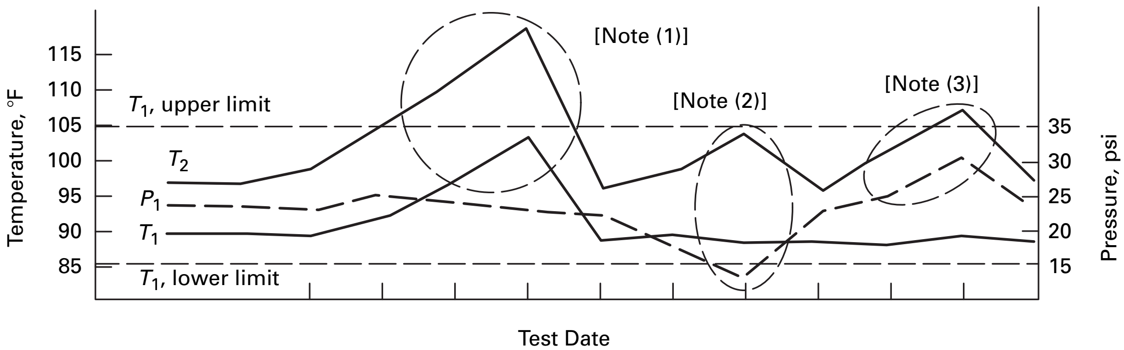
(1) High ΔT across the engine. Possible causes, with $T_4 - T_3$ = constant, are:
- *(a)* air in system
- *(b)* combustion gas to jacket water leak
- *(c)* restriction in jacket water system

(2) ΔT satisfactory, but temperature increasing. Possible causes:
- *(a)* heat exchanger fouling
- *(b)* faulty three-way temperature valve
- *(c)* sea-water system restricted
- *(d)* service water inlet temperature too high

(3) Normal operation conditions

Fig. C-3 Intercooler Water System





Trend Plotting — Air Cooler Water Temperature to T_1 and From T_2 Cooler Pump Pressure P_1

NOTES:

(1) Both temperatures rising; pressure remains constant:

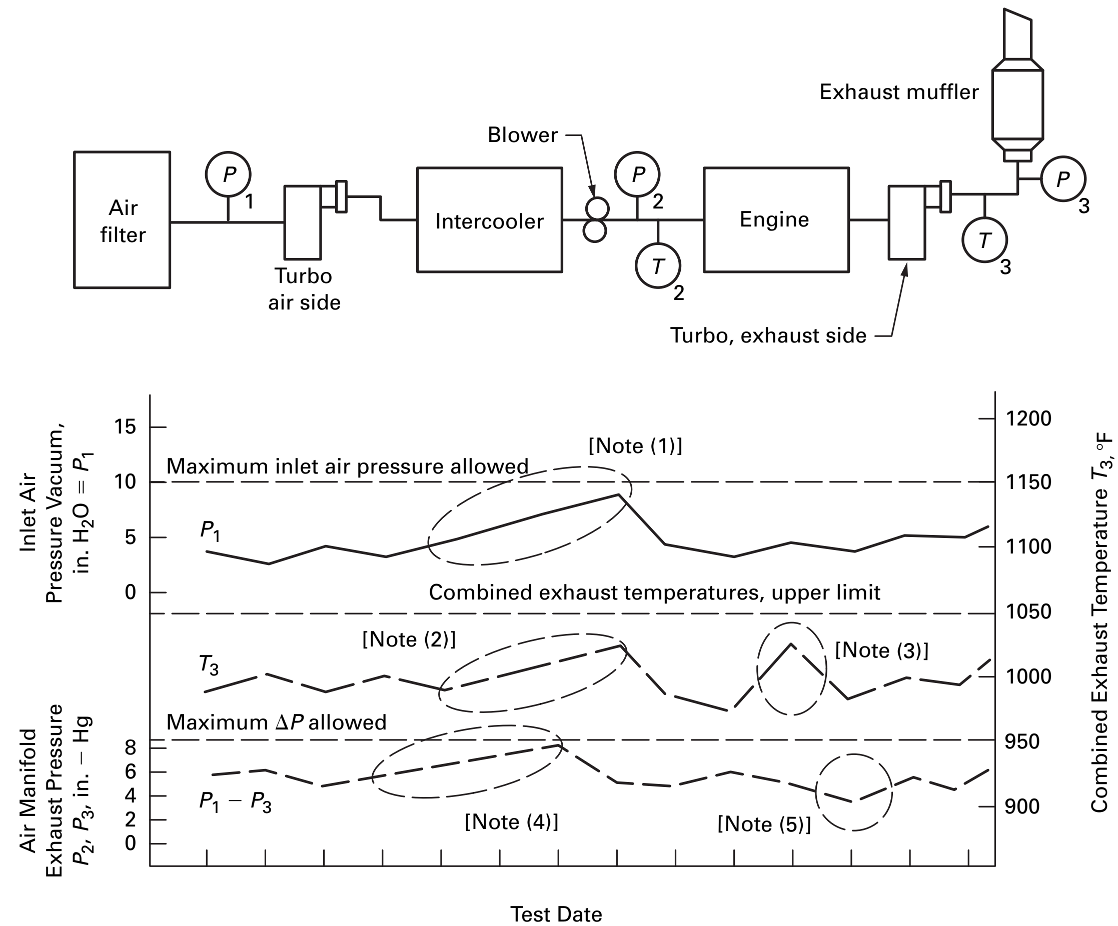
(a) temperature control valve (three-way) failing

(b) restricted service water flow (T_4 – T_3 rising)

(2) Temperature rise across air cooler and decreasing pump discharge pressure: air in system.

(3) Temperature rise across air cooler and pump discharge pressure increasing: coolers becoming clogged and requiring cleaning.

Fig. C-4 Typical Air/Exhaust System



Trend Plotting — Air/Exhaust System
Inlet Air Pressure (Vacuum) — P_1 =_______
Air Manifold/Exhaust Back Pressure = $P_2 - P_2$ = _______
Combined Exhaust Temperature = T_3 = _______

NOTES:

(1) Gradually increasing inlet air vacuum: inlet air filters plug and require cleaning or changing.

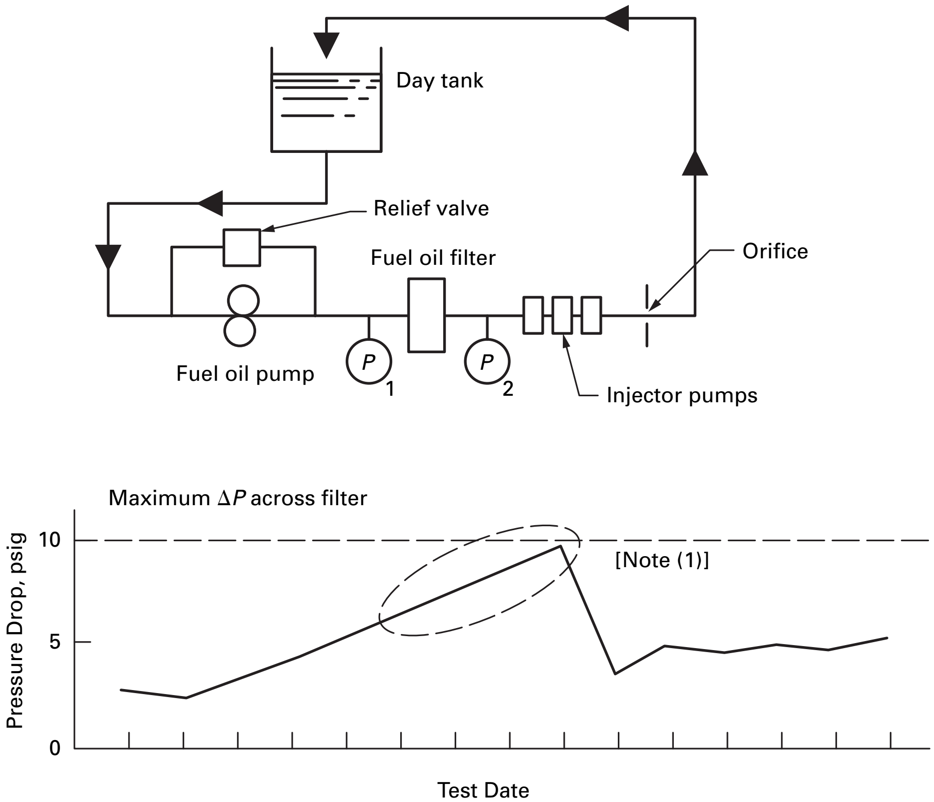
(2) Gradually increasing combined exhaust temperatures may be caused by:
- *(a)* exhaust/turbocharger flow restriction
- *(b)* turbo deficiency
- *(c)* low air flow caused by plugged air inlet filters
- *(d)* injection timing change (retarded)
- *(e)* faulty injection nozzle, not proper spray pattern

(3) High combined exhaust temperatures. Possible causes:
- *(a)* faulty injection nozzle, nozzle streams foul
- *(b)* injection timing change (retarded)

(4) Increasing ΔP across engine. Possible causes:
- *(a)* exhaust flow restrictions
- *(b)* turbocharger deficiency

(5) Low ΔP along with low inlet air vacuum and low combined exhaust temperatures: could indicate the test load was low.

Fig. C-5 Typical Fuel Oil System



Trend Plotting — Fuel Filter $\Delta P = P_1 - P_2$

NOTE:
(1) Pressure drop across filter increasing: filter needs cleaning or elements need replacement.

PART 21

PART 21
Inservice Performance Testing of Heat Exchangers in Light-Water Reactor Power Plants

1 INTRODUCTION

1.1 Scope

This Part establishes the requirements for preservice and inservice testing to assess the operational readiness of certain heat exchangers used in nuclear power plants.

The heat exchangers covered are those 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.

This Part establishes test intervals, parameters to be measured and evaluated, acceptance criteria, corrective actions, and record requirements.

1.2 Exclusions

This Part does not address the following:

(a) flow-induced vibration

(b) structural integrity

(c) pressure-retaining capability

(d) erosion or corrosion

(e) other mechanical or structural performance concerns

(f) effects of system performance on heat exchangers (e.g., the system providing insufficient flow to a heat exchanger)

(g) any related system testing (e.g., flow balance testing)

(h) steam generators

1.3 Owner's Responsibility

The Owner shall identify, based on individual plant design basis, those heat exchangers that are considered to be covered by this Part and shall prioritize those heat exchangers in accordance with the guidance provided in this Part. The Owner shall select the most appropriate test or monitoring method and interval for each heat exchanger, so identified, based on the criteria contained in this Part.

The Owner shall be responsible for the operational readiness of all safety-related heat exchangers by following the program requirements as described in para. 5.1.

2 DEFINITIONS

These definitions are provided to ensure a uniform understanding of selected terms used in this Part.

accuracy: the closeness of agreement between a measured value and the true value.

baseline data: data collected at specific operating conditions that establish a basis to which subsequent data may be compared.

baseline test: a performance test to establish baseline data.

bias error: the difference between the average of the total population and the true value.

biofilm: a fouling layer consisting of microorganisms and their by-products.

clean fluid: of the two fluids, the one that has the lesser potential for fouling a heat exchanger.

component design limit: that value of heat exchanger performance (usually specified by the manufacturer as the design point) such that if exceeded, although not affecting the operational readiness of the component, may result in component degradation and component reliability concerns.

confidence level: the relative frequency that the calculated statistic is correct.

cooling fluid: any fluid (e.g., water, air, or oil) that serves to carry heat away from the process fluid by the transfer of heat through the heat exchanger.

correlational uncertainty: the uncertainty embedded in the calculational process due to the mathematical models employed (e.g., heat-transfer film coefficients).

coverage: the frequency at which an interval estimate of a parameter may be expected to contain the true value.

design accident conditions: the set of conditions and constraints that are to be satisfied by the heat exchanger for the heat exchanger to meet the safety requirements of the system that it serves.

design basis: information that identifies the specific functions to be performed by a structure, system, or component of a facility, and the specific values or ranges of values chosen for controlling parameters as reference bounds for design.

design point: the set of operating conditions and constraints that are satisfied by the heat exchanger as specified in the heat exchanger specification sheet.

exclusion criteria: the set of conditions that must be avoided for a testing or monitoring method to be effective.

film coefficient: the rate of heat transfer per unit area per unit temperature differential across the boundary layer between either the cooling or the process fluid and the heat-transfer surface.

flow blockage: a reduction in heat-transfer surface or a reduction in flow rate caused by fouling.

fouling fluid: of the two fluids, the one that has the greater potential for fouling a heat exchanger.

fouling resistance: a resistance to heat flow caused by the deposition of corrosive products, dirt, or other foreign material on a heat-transfer surface.

heat duty: the heat transferred per unit of time from one fluid to another.

inclusion criteria: the set of conditions that must be satisfied for a testing or monitoring method to be effective.

inservice test: a test to determine the operational readiness of a structure, system, or component after first electrical generation by nuclear heat.

instrument delay: the characteristic of measuring instruments to give an indicated value that lags the actual value during transient conditions.

instrument loop: two or more items working together to provide a single output.

measurement error: the difference between the true value and the measured value of a parameter. It includes both bias and precision errors.

monitoring method: a method that is used to indirectly evaluate heat exchanger thermal performance.

nominal result: the test result that is calculated using average parameter values.

operability: a system, subsystem, train, component, or device shall be operable when it is capable of performing its specified safety functions. All necessary attendant instrumentation, controls, electrical power, cooling or seal water, lubrication, or other auxiliary equipment that are required for the system, subsystem, train, component, or device to perform its function(s) shall also be capable of performing their related support function(s).

operational readiness: the ability of a component to perform its specified functions.

overall heat-transfer coefficient: the average rate of heat transfer per unit area per unit temperature differential between the cooling and process fluids under specified fouling conditions.

Owner: the organization legally responsible for the construction and/or operation of a nuclear facility including but not limited to one who has applied for, or who has been granted, a construction permit or operating license by the regulatory authority having lawful jurisdiction.

parameter: a measured quantity (i.e., temperature, pressure, or flow) used in calculating a test result.

precision error: the closeness of agreement between repeated independent measurements of a single parameter.

precision index: the sample standard deviation based on N measurements.

preservice test: a test performed during the period after completion of construction activities related to the component and before first electrical generation by nuclear heat or in an operating plant before the component is initially placed in service.

process fluid: any fluid that supplies the heat to the heat exchanger.

required action limit: that value of heat exchanger performance such that, if corrective actions are not performed prior to the next scheduled test or monitoring, the system operability limit would be exceeded.

result sensitivity: the actual change in a result due to changing the measurement parameter by its measurement error.

system operability limit: the minimum thermal performance required of a heat exchanger so as to ensure the operational readiness of its system.

temperature effectiveness: the ratio of the temperature change of the tube side fluid to the difference between the two fluid inlet temperatures (sometimes called temperature efficiency). For plate-type heat exchangers, the cooling fluid side can be considered as the tube side.

temperature of interest: a temperature that is chosen to be monitored because of its dependency on the thermal performance of a heat exchanger.

test conditions: the conditions experienced by a heat exchanger undergoing a test.

testing method: a method that is used to quantitatively evaluate heat exchanger thermal performance.

test point: the set of parameters retrieved from the heat exchanger at a specific test condition.

test result: a value calculated from a number of parameters.

total uncertainty: the estimated error limit of a test result for a given coverage. Total uncertainty results from the propagation of measurement errors and correlational uncertainties through a calculational process and is statistically applied to the test result.

transport delay: the time required for the process fluid to travel between the heat exchanger and the point of measurement.

3 REFERENCES

3.1 Standard References

The following is a list of publications referenced in this Part. Consult the latest edition available.

Standard for Power Plant Heat Exchangers
Publisher: Heat Exchange Institute, Inc. (HEI), 1300 Sumner Avenue, Cleveland, OH 44115

Standards of Tubular Exchanger Manufacturers Association
Publisher: Tubular Exchanger Manufacturers Association, Inc. (TEMA), 25 North Broadway, Tarrytown, NY 10591

3.2 Appendix References

In addition to the standard references, the following additional references were used in preparing the Appendix to this Part. Consult the latest edition available.

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K. P. Singh and A. I. Soler, Mechanical Design of Heat Exchangers and Pressure Vessel Components (1984; Chapters 4 and 12)
Publisher: Arcturus Publishers, Cherry Hill, NJ

K. P. Singh, Theory and Practice of Heat Exchanger Design (Chapter 9)
Publisher: Arcturus Publishers, Cherry Hill, NJ

N. Stambaugh, W. Closser, and F. J. Mollerus, EPRI Report NP-7552, Heat Exchanger Performance Monitoring Guidelines
Publisher: Electric Power Research Institute (EPRI), 3412 Hillview Avenue, P.O. Box 10412, Palo Alto, CA 94304

ASME Steam Tables, 5th edition (1983)
Publisher: The American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016-5990; Order Department: 22 Law Drive, P.O. Box 2300, Fairfield, NJ 07007-2300

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ASME Boiler and Pressure Vessel Code, Section II, Materials, Part D: Properties, Table TCD (1992)
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R. A. Bowman, A. C. Mueller, and W. M. Nagle, "Mean Temperature Difference in Design," ASME Transactions (May 1940): 283–294 [use for single and multipass shells, even tube passes]
Publisher: The American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016-5990; Order Department: 22 Law Drive, P.O. Box 2300, Fairfield, NJ 07007-2300

F. K. Fischer,"Mean Temperature Difference Correction in Multipass Exchangers," Industrial and Engineering Chemistry, Vol. 30, (1938): 377–383 (use for single and multipass shells, odd tube passes)

L. Jaw, "Temperature Relations in Shell and Tube Exchangers Having One-Pass Split-Flow Shells," ASME Transactions, Journal of Heat Transfer (August 1964): 408–416 [use for divided flow shells]
Publisher: The American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016-5990; Order Department: 22 Law Drive, P.O. Box 2300, Fairfield, NJ 07007-2300

K. P. Singh and M. J. Holtz, "A Comparison of Thermal Performance of Two and Four Pass Designs for Split Flow Shells," ASME Transactions, Journal of Heat Transfer, Vol. 103, No. 1 (February 1981): 169–172 [use for split flow shells]
Publisher: The American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016-5990; Order Department: 22 Law Drive, P.O. Box 2300, Fairfield, NJ 07007-2300

F. J. L. Nicole, "Exchanger Design: A General Approximate Explicit Equation," ASME Transactions, Journal of Heat Transfer (February 1975): 5–8 [use for crossflow shells]
Publisher: The American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016-5990; Order Department: 22 Law Drive, P.O. Box 2300, Fairfield, NJ 07007-2300

R. C. Lord, P. E. Minton, and R. P. Slusser, "Design of Heat Exchangers," Chemical Engineering (January 26, 1970): 96–116

ASME PTC 19.1-1998, Test Uncertainty
Publisher: The American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016-5990; Order Department: 22 Law Drive, P.O. Box 2300, Fairfield, NJ 07007-2300

H. W. Coleman and W. G. Steele, Experimentation and Uncertainty Analysis for Engineers (1989)
Publisher: John Wiley & Sons

A Mathematical Model for Assessing the Uncertainties of Instrumentation Measurements for Power and Flow of PWR Reactors, NUREG/CR-3659 (1985)

H. S. Bean, ed., Fluid Meters: Their Theory and Application (1971)

AMCA 99 Standard, Fan Application Manual, Part 3: A Guide to the Measurement of Fan-System Performance in the Field (1986)
Publisher: Air Moving and Conditioning Association (AMCA)

HVAC Systems: Testing, Adjusting, and Balancing (1983)
Publisher: Sheet Metal and Air Conditioning Contractors' National Association

ASHRAE Handbook of Fundamentals (1989)
Publisher: American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE), 1791 Tullie Circle, NE, Atlanta, GA 30329

National Standard for Testing and Balancing Heating, Ventilating, and Air Conditioning Systems, 5th edition (1989)
Publisher: American Air Balance Council (AABC)

4 SELECTION AND PRIORITIZATION OF HEAT EXCHANGERS

4.1 Heat Exchanger Selection

Those heat exchangers 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, shall be selected for testing or monitoring, based on individual plant design basis. For the purposes of this Part, steam generators shall be excluded from the selection process.

4.2 Heat Exchanger Prioritization

Heat exchangers selected in para. 4.1 shall be prioritized for testing or monitoring based on the criteria of paras. 4.2.1 through 4.2.3. These criteria shall be progressively applied according to the interval defined in para. 5.4 to ensure that the requirement of para. 4.1 is met.

4.2.1 Fouling Potential. If a heat exchanger is served by a fluid that has a high potential for fouling, then that heat exchanger should be given high priority.

CAUTION: For plate heat exchangers, even under similar service conditions, differences in flow distribution due to variations of plate pattern design may result in different fouling tendencies.

4.2.2 System Configuration. If there are two or more heat exchangers in parallel and all are subjected to essentially identical service conditions (i.e., essentially all the same flow rates and heat loads, none stagnant for long periods of time), then only one of the heat exchangers needs to be given high priority initially. For identical heat exchangers in series, the first one in the series (as defined by the fouling fluid) should be given high priority initially, as it would be expected to collect the majority of fouling deposits. If, however, the heat loads for either parallel or series configurations are not identical, then the one with the highest heat load should be given high priority.

CAUTION: If heat exchanger geometries and tube plugging levels are different, then tube velocities should be compared as part of the prioritization process. Also, if the fouling fluid is on the shell side, even if the heat exchangers are identical, there is less predictability of individual heat exchanger performance due to potential structural problems and nonuniform fouling.

4.2.3 Thermal Performance. If there is reason to believe that a heat exchanger is experiencing thermal performance degradation (possibly due to structural or mechanical problems), then the suspect heat exchanger should be given high priority.

5 BASIC REQUIREMENTS

5.1 Program Requirements

A program shall be established to ensure the operational readiness of the heat exchangers covered by this Part. This program shall consist of testing or monitoring (or both), trending, establishing intervals and acceptance criteria, performing uncertainty analysis and corrective actions, and maintaining appropriate records and supporting documentation. While testing is preferred, monitoring may be used instead if sufficient technical justification can be shown that testing is not feasible.

This program should incorporate periodic reviews in which the test or monitoring methods and intervals are evaluated to be the most appropriate for use in meeting the intent of this Part and such that required action limits are not exceeded. These reviews should consider advances in testing and monitoring technologies, operating histories of the heat exchangers, fouling rates, changes in cooling fluid quality, heat load availability, and previous test or monitoring results.

5.2 Preservice Requirements[1]

Preservice testing or monitoring shall be performed on a heat exchanger in the clean condition prior to or after installation in the plant.

Preservice testing or monitoring provides data and results that should be used to establish a preservice baseline for comparing with future inservice testing or monitoring results. Preservice testing or monitoring should be used to compare the as-designed heat exchanger data provided by the vendor with the as-built heat exchanger.

The preservice testing or monitoring method selected should be the same as the inservice testing or monitoring method. However, if the preservice testing or monitoring method is different than the inservice testing or monitoring method (i.e., a preservice testing or monitoring method may be chosen specifically just to verify as-built characteristics), then the inservice testing or monitoring method shall also be performed as a part of, or in conjunction with, the preservice testing or monitoring method. This will provide a preservice baseline for comparing with future inservice testing or monitoring results.

[1] The requirements of para. 5.2 are applicable only during the period of time as specified in the definition of preservice test (see para. 2).

5.3 Inservice Requirements

Inservice testing or monitoring shall be performed to satisfy the program requirements of para. 5.1.

Inservice testing or monitoring shall be performed prior to performing any corrective action that would impact the thermal performance of the heat exchanger (i.e., cleaning) to determine the "as-found" condition of the heat exchanger. This "as-found" condition is essential for establishing appropriate testing or monitoring intervals.

Inservice testing or monitoring should be conducted as soon as practicable following corrective action, unless the effectiveness of the corrective action has been documented to be consistently repeatable.

Baseline inservice testing or monitoring shall be performed as soon as practicable following structural changes (excluding minor tube plugging) that make significant permanent changes to the thermal characteristics of the heat exchanger (i.e., modifying baffle plates). This baseline inservice testing or monitoring shall be conducted on a clean heat exchanger to provide a comparison with future inservice testing or monitoring results.

5.4 Interval Requirements

Testing or monitoring intervals shall be established such that the required action limits are not exceeded (see para. 9.3 and Fig. 1). If the testing or monitoring interval [I(test) in Fig. 1] exceeds the maximum testing or monitoring interval, which assumes no corrective actions are performed [I(max) in Fig. 1], then corrective action shall be taken.

Intervals shall be established based on preservice (or baseline inservice) testing or monitoring and subsequent inservice testing or monitoring.

Intervals shall be adjusted as part of the program review, based on fouling rate, type of fouling, operational requirements, heat load availability, etc., to guarantee satisfactory performance during the interval.

Intervals shall not exceed 10 years.

6 SELECTION OF METHODS

The appropriate testing or monitoring method shall be selected for each heat exchanger in the program.

If test methods are chosen, they may be supplemented with monitoring methods performed between the tests. Monitoring methods may also be used to help determine the need for testing.

Selection of the testing and monitoring methods should be made by assessing their respective inclusion and exclusion criteria, additional criteria related to testing and monitoring conditions (see para. 7), and errors, sensitivities, and uncertainties (see para. 8). The criteria for each method should be applied to each of the heat exchangers selected until, through the process of elimination, the most appropriate method is selected (see Fig. 2).

While the testing and monitoring methods presented here should cover the majority of applications, there is no intent to limit the program to these methods if more appropriate testing and monitoring methods are devised for particular applications.

6.1 Functional Test Method

6.1.1 Objective. The objective of the functional test method is to provide an indication of thermal performance degradation of a heat exchanger over time by measuring a temperature that is dependent on the thermal performance of the heat exchanger and to compare that temperature with established acceptance criteria (see para. 9).

6.1.2 Descriptive Summary. The functional test method will demonstrate directly that the heat exchanger is capable of meeting its acceptance criteria (see para. 9). It is applied to the temperature of the component or area that the heat exchanger is designed to cool (the "temperature of interest") rather than to the temperatures into or out of the heat exchanger itself. Examples of temperatures of interest are motor or pump-bearing temperatures, bearing oil temperatures, pump room temperatures, and diesel jacket water temperatures.

After meeting the inclusion and exclusion criteria, the temperature of interest is then measured and compared to the acceptance criteria for that heat exchanger. A typical example is presented in Nonmandatory Appendix C, para. C-1.

6.1.3 Inclusion Criteria. The functional test method shall be considered if

(a) the acceptance criteria (see para. 9) of the heat exchanger is stated explicitly in terms of a "temperature of interest" (i.e., motor stator temperature for a motor cooler).

(b) design accident flows and inlet temperatures can be achieved during test conditions.[2]

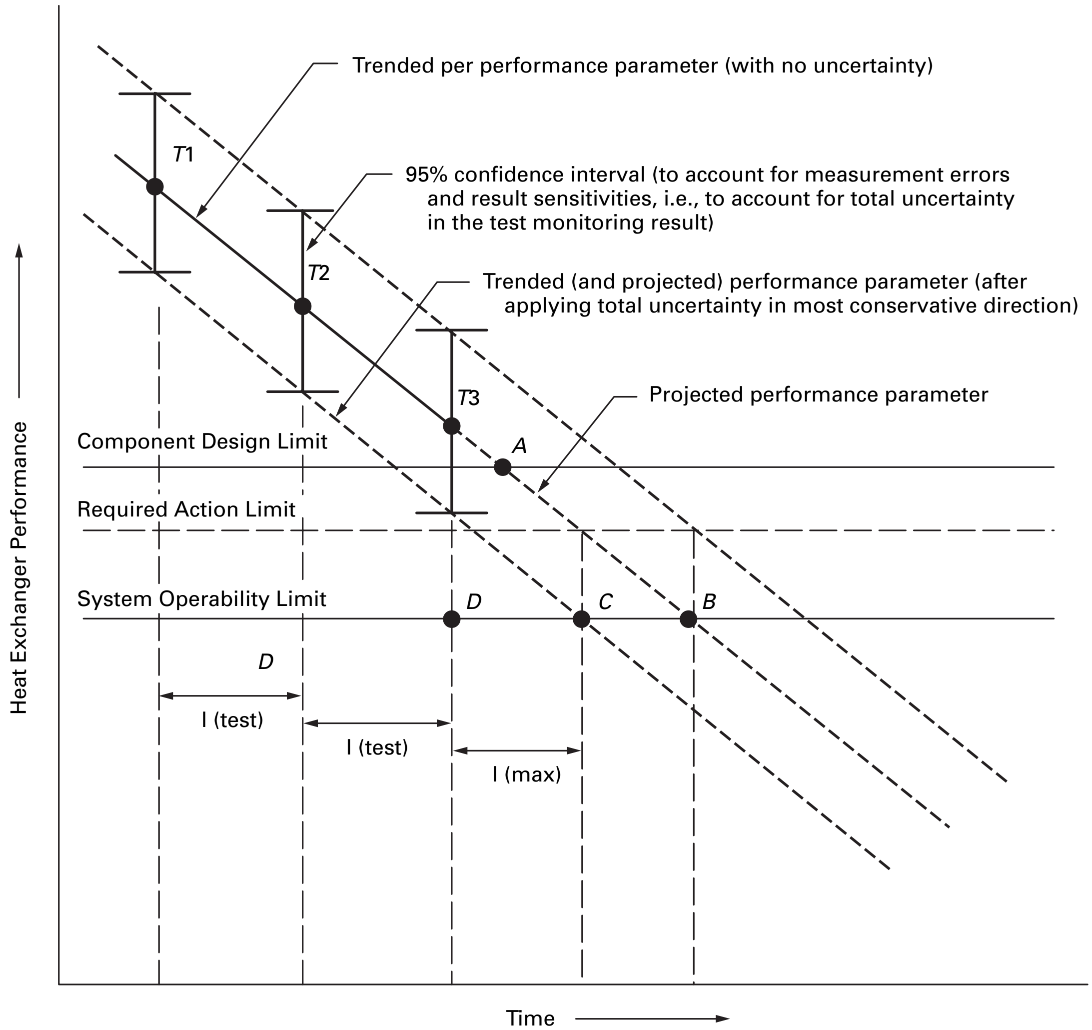
(c) the heat exchanger can be subjected to the same (or greater) heat load that would be present under the accident conditions (i.e., for a pump room cooler, the pumped fluid temperature, any ventilation function, and the motor load should be as they would be under the accident condition).

(d) steady-state conditions (see para. 7.1) do exist.

6.1.4 Exclusion Criteria. There are no exclusion criteria for the functional test method.

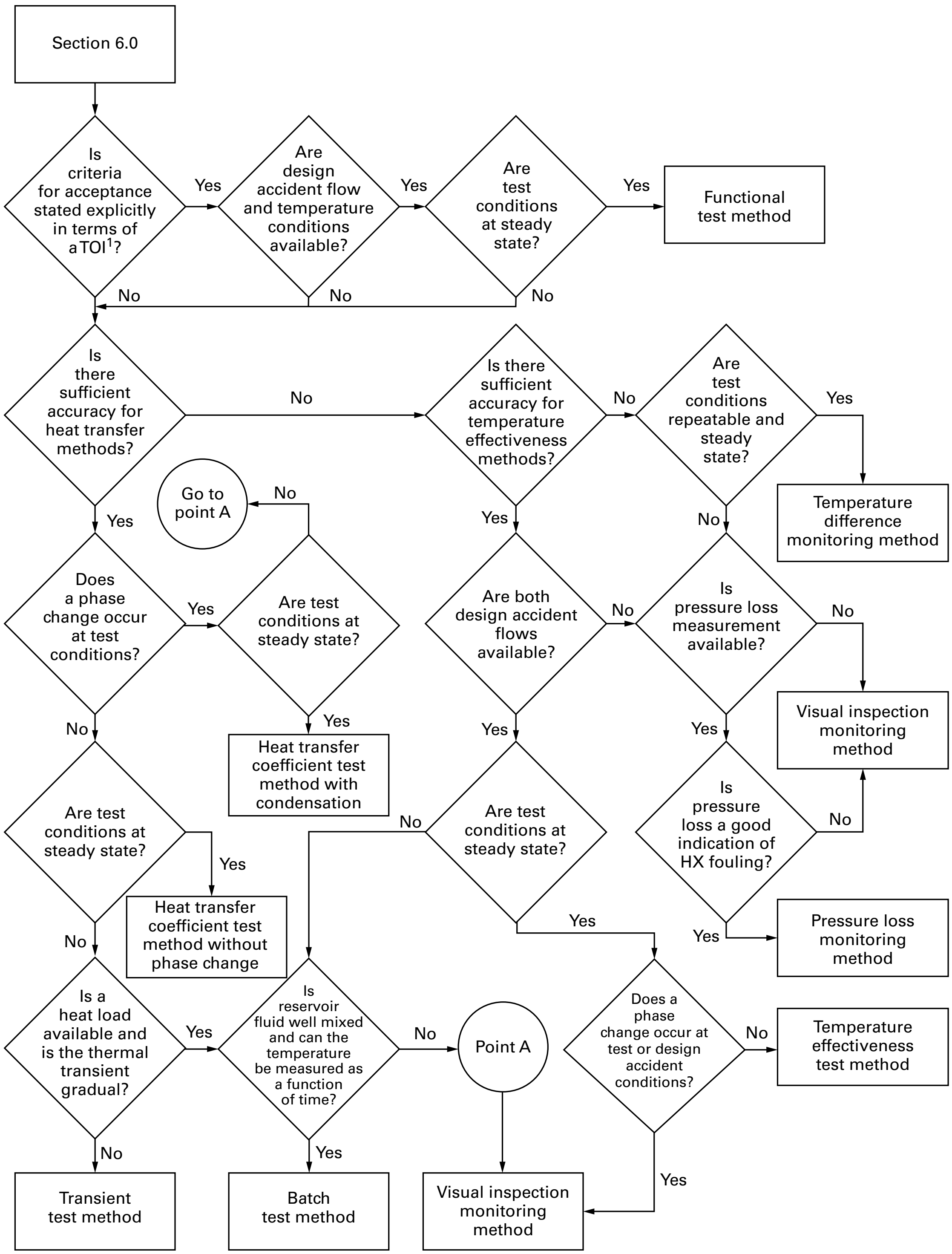
[2] When operational restrictions prohibit the establishment of design accident condition equipment heat load or process inlet temperature for the conduct of this test, an equivalent heat load may be applied by the use of portable heaters or other similar means.

Fig. 1 Intervals, Limits, and Parameter Trending (Typical)



LEGEND:
I (test) = historical test or monitoring interval
I (max) = maximum test or monitoring interval if no corrective actions are performed. If I (max) < I (test) then corrective action shall be taken
*T*1, *T*2, *T*3 = successive test or monitoring data points
*T*3 = latest test or monitoring data point
A = heat exchanger unable to satisfy requirements specified on component data sheet (with no uncertainty)
B = heat exchanger unable to satisfy requirements for operational readiness (with no uncertainty)
C = heat exchanger unable to satisfy requirements for operational readiness (after accounting for total uncertainty by applying 95% confidence interval in most conservative direction)
*T*3 − *D* = current "absolute" operating margin (with no uncertainty)

Fig. 2 Method Selection Chart



NOTE:
(1) Temperature of interest.

6.1.5 Required Parameter. The temperature of interest shall be measured to quantitatively evaluate the heat exchanger thermal performance using the functional test method.

NOTE: The component of interest must be functioning within the design basis during testing to ensure this method accurately represents heat exchanger performance.

6.2 Heat-Transfer Coefficient Test Method (Without Phase Change)

6.2.1 Objective. The objective of the heat-transfer coefficient test method (without phase change) is to determine the heat-transfer capability of a heat exchanger when a phase change is not occurring at test conditions.

6.2.2 Descriptive Summary. After meeting the inclusion and exclusion criteria and measuring the required parameters, a methodology is applied (a typical example is presented in Nonmandatory Appendix C, para. C-2) that will result in the calculation of a fouling resistance for the heat exchanger and the determination of the heat-transfer capability of the heat exchanger to ensure operational readiness.

6.2.3 Inclusion Criteria. The heat-transfer coefficient test method (without phase change) shall be considered if

(a) the design basis specifies safety function (or acceptance criteria, see para. 9) in terms of heat duty (Btu/hr).

(b) sufficient accuracy (in accordance with para. 8) is achievable at test conditions.

(c) a phase change does not occur at test conditions.

(d) steady-state conditions (see para. 7.1) do exist.

6.2.4 Exclusion Criteria. The heat-transfer coefficient test method (without phase change) shall not be considered if

(a) the flow on the shell side traverses flow regimes in going from the test condition to the design accident condition and the resulting correlational inaccuracy cannot be accounted for (see para. 8.6).

(b) the fouling rate is such that operability cannot be maintained between tests (because heat loads are not available; see paras. 5.4 and 9).

6.2.5 Required Parameters. At least five of the following six parameters [paras. 6.2.5(a) through (f)] shall be measured to quantitatively evaluate the heat exchanger thermal performance using the heat-transfer coefficient test method (without phase change). The sixth parameter may be calculated from the other five (see para. 8.5). The accuracy of the calculated parameter depends on the accuracy of the other five parameters (see para. 8).

(a) cooling fluid inlet temperature

(b) cooling fluid outlet temperature

(c) process fluid inlet temperature

(d) process fluid outlet temperature

(e) cooling fluid flow rate

(f) process fluid flow rate

Other relevant parameters may be measured to reduce the total uncertainty in the calculated result.

6.3 Heat-Transfer Coefficient Test Method (With Condensation)

6.3.1 Objective. The objective of the heat-transfer coefficient test method (with condensation) is to determine the heat-transfer capability for heat exchangers having condensation from steam-air mixtures (e.g., air coolers or air-to-water heat exchangers) during test conditions.

6.3.2 Descriptive Summary. After meeting the inclusion and exclusion criteria and measuring the required parameters, a methodology is applied (a typical example is presented in Nonmandatory Appendix C, para. C-3) that will result in the calculation of a fouling resistance for the heat exchanger and the determination of the heat-transfer capability of the heat exchanger to ensure operational readiness.

6.3.3 Inclusion Criteria. The heat-transfer coefficient test method (with condensation) shall be considered if

(a) the design basis specifies safety function (or acceptance criteria, see para. 9) in terms of heat duty (Btu/hr).

(b) sufficient accuracy (in accordance with para. 8) is achievable at test conditions.

(c) condensation occurs during the test conditions.

(d) steady-state conditions (see para. 7.1) do exist.

6.3.4 Exclusion Criteria. The heat-transfer coefficient test method (with condensation) shall not be considered if

(a) the flow on the shell side traverses flow regimes in going from the test condition to the design accident condition and the resulting correlational inaccuracy cannot be accounted for (see para. 8.6).

(b) the fouling rate is such that operability cannot be maintained between tests (because heat loads are not available, see paras. 5.4 and 9).

6.3.5 Required Parameters. At least seven of the following ten parameters [paras. 6.3.5(a) through (j)] shall be measured to quantitatively evaluate the heat exchanger thermal performance using the heat-transfer coefficient test method (with condensation). Measurement of the following parameter (a) is required:

(a) process fluid (steam-air mixture) pressure

In addition, at least five of the following six parameters [(b) through (g)] shall be measured. The sixth parameter may be calculated from the other five (see para. 8.5). The accuracy of the calculated parameter will depend on the accuracy of the other five parameters (see para. 8).

(b) cooling fluid inlet temperature

(c) cooling fluid outlet temperature

(d) process fluid (steam-air mixture) inlet temperature

(e) process fluid (steam-air mixture) outlet temperature

(f) cooling fluid flow rate

(g) process fluid (steam-air mixture) flow rate

In addition to the above, any one of the following three parameters [paras. 6.3.5(h) through (j)] is required:

(h) process fluid (steam-air mixture) inlet relative humidity

(i) process fluid (steam-air mixture) outlet relative humidity

(j) process fluid (steam-air mixture) condensation rate

Other relevant parameters may be measured to reduce the total uncertainty in the calculated result.

6.4 Transient Test Method

6.4.1 Objective. The objective of the transient test method is to determine the thermal performance of a heat exchanger when steady-state conditions (see para. 7.1) cannot be achieved during the test.

6.4.2 Descriptive Summary. After meeting the inclusion and exclusion criteria and measuring the required parameters, a methodology is applied (an example is presented in Nonmandatory Appendix C, para. C-4) that will result in the calculation of a fouling resistance for the heat exchanger and the determination of the heat-transfer capability of the heat exchanger to ensure operational readiness.

The transient test method refers to measuring the time it takes for temperatures to change in response to a transient heat load being placed on the heat exchanger. The transient test method may be used where flow rates or inlet temperatures (or both) vary during the test. An example would be the cooling of the component cooling water loop after its initial temperature has been allowed to increase temporarily by stopping the cooling water flow to the component cooling water heat exchanger.

6.4.3 Inclusion Criteria. The transient test method shall be considered if

(a) the design basis specifies safety function (or acceptance criteria, see para. 9) in terms of heat duty (Btu/hr).

(b) sufficient accuracy (in accordance with para. 8) is achievable at test conditions.

(c) an appreciable heat load is available such that the temperature of the process fluid can be raised temporarily.

(d) a phase change does not occur at test conditions.

6.4.4 Exclusion Criteria. The transient test method shall not be considered if

(a) the transient is a steep function of time, such that the thermal inertia of the heat exchanger becomes significant ("steep" being defined as the left sides of eqs. 1 through 3 in para. 7.1 being $> 0.25Q$).

(b) the value of thermal inertia (per para. 7.1) cannot be calculated.

(c) the flow on the shell side traverses flow regimes in going from the test condition to the design accident condition and the resulting correlational inaccuracy cannot be accounted for (see para. 8.6).

(d) the fouling rate is such that operability cannot be maintained between tests (because heat loads are not available, see paras. 5.4 and 9).

(e) significant condensation occurs at the test conditions.

6.4.5 Required Parameters. At least seven of the following eight parameters [(a) through (h)] shall be measured to quantitatively evaluate the heat exchanger thermal performance using the transient test method. Measurement of the following six parameters [(a) through (f)] is required:

(a) cooling fluid inlet temperature time history

(b) process fluid inlet temperature time history

(c) cooling fluid flow rate time history

(d) process fluid flow rate time history

(e) cooling fluid initial temperature profile inside the heat exchanger

(f) process fluid initial temperature profile inside the heat exchanger

In addition, at least one of the following two parameters [(g) and (h)] shall be measured:

(g) cooling fluid outlet temperature time history

(h) process fluid outlet temperature time history

Other relevant parameters may be measured to reduce the total uncertainty in the calculated result.

6.5 Temperature Effectiveness Test Method

6.5.1 Objective. The temperature effectiveness test method is used to predict the effectiveness of the heat exchanger at a known reference point (design accident condition, design point, test point, established using the heat-transfer coefficient test method). This method assumes that the process and cooling fluid mass flow rates at the test point are essentially the same as those at the reference point (within ± 5%). This test method is accomplished by collecting the process and cooling fluid inlet and outlet temperatures at the test point, choosing two temperatures at the reference point, and calculating the remaining two temperatures at the reference point.

6.5.2 Descriptive Summary. The temperature effectiveness is the ratio of the temperature change of the tube-side fluid to the difference between the two fluid inlet temperatures (sometimes called temperature efficiency). For plate-type heat exchangers, the cooling fluid side may be considered to be the tube side.

NOTE: The temperature effectiveness is defined with respect to the tube-side terminal difference in the foregoing. Alternatively, the effectiveness may be defined with respect to the shell-side terminal difference; perform all required calculations in a consistent manner.

After meeting the inclusion and exclusion criteria and measuring the required parameters, the temperatures that are measured are applied using a methodology (a typical example is presented in Nonmandatory Appendix C, para. C-5) that will result in the determination of two of the four temperatures at the known reference point, which can then be compared with the acceptance criteria. This method is conservative if the design accident condition temperatures are higher than the test condition temperatures because of the improved heat-transfer coefficient at higher temperatures.

6.5.3 Inclusion Criteria. The temperature effectiveness test method shall be considered if

(a) sufficient accuracy (in accordance with para. 8) is achievable at test conditions.

(b) both test flows can be manipulated to within ± 5% of the design accident flows.

(c) design accident temperatures cannot be achieved during test conditions (e.g., for pump room coolers).

(d) steady-state conditions (see para. 7.1) do exist.

6.5.4 Exclusion Criteria. If a phase change is expected to occur at either the test or known reference point, then the temperature effectiveness test method shall not be considered.

6.5.5 Required Parameters. Six of the following eight parameters [paras. 6.5.5(a) through (h)] shall be used to quantitatively evaluate the heat exchanger thermal performance using the temperature effectiveness test method. Measurement of the following four parameters [(a) through (d)] is required.

(a) cooling fluid inlet temperature at test conditions

(b) cooling fluid outlet temperature at test conditions

(c) process fluid inlet temperature at test conditions

(d) process fluid outlet temperature at test conditions

In addition, only two of the following four parameters [(e) through (h)] shall be chosen:

(e) cooling fluid inlet temperature at the reference point

(f) cooling fluid outlet temperature at the reference point

(g) process fluid inlet temperature at the reference point

(h) process fluid outlet temperature at the reference point

Other relevant parameters may be measured to reduce the total uncertainty in the calculated result.

6.6 Batch Test Method

6.6.1 Objective. The objective of the batch test method is to determine the temperature effectiveness and the overall heat-transfer coefficient of a heat exchanger by measuring the aggregate quantity of heat removed by the heat exchanger in the batch mode from a source of large thermal capacity (process fluid reservoir). It provides an alternative to the previous test methods when steady-state test conditions (see para. 7.1) cannot be achieved.

The batch test method is accomplished by measuring the initial process fluid and final process fluid reservoir temperatures over a measured time period, while holding the cooling fluid inlet temperature constant. Using the thermal capacity of the process fluid reservoir, the temperature effectiveness and the overall heat-transfer coefficient can be calculated.

NOTE: The description presented herein assumes the reservoir to contain the process fluid. The test and the calculational procedures will remain valid if the reverse condition exists (i.e., a cool reservoir is being heated by the process fluid).

6.6.2 Descriptive Summary. After meeting the inclusion and exclusion criteria and measuring the required parameters, a methodology is applied (a typical example is presented in Nonmandatory Appendix C, para. C-6) that will result in the determination of the temperature effectiveness and the overall heat-transfer coefficient of the heat exchanger.

6.6.3 Inclusion Criteria. The batch test method shall be considered if

(a) sufficient accuracy (in accordance with para. 8) is achievable at test conditions.

(b) the temperature of the process fluid reservoir can be measured as a function of time.

(c) the fluid in the process fluid reservoir is well mixed.

(d) the heat exchanger is the sole medium for the enthalpy change in the process fluid reservoir during the test.

(e) steady-state conditions (see para. 7.1) do not exist.

6.6.4 Exclusion Criteria. The batch test method shall not be considered if

(a) the flow on the shell side traverses flow regimes in going from the test condition to the design accident condition and the resulting correlational inaccuracy cannot be accounted for (see para. 8.6).

(b) the fouling rate of the heat exchanger is such that the overall heat transfer of the heat exchanger is changed during the test.

(c) the fluid in the process fluid reservoir undergoes a phase change.

(d) the flow rate or inlet temperature of the cooling fluid is subject to variation during the test.

6.6.5 Required Parameters. The following six parameters [(a) through (f)] shall be determined to quantitatively evaluate the heat exchanger thermal performance using the batch test method. These six parameters are required to calculate the temperature effectiveness:

(a) mass of the process fluid
(b) initial process fluid inlet temperature
(c) final process fluid inlet temperature
(d) time required to cool the process fluid
(e) cooling fluid flow rate
(f) cooling fluid inlet temperature

In addition, to calculate the overall heat-transfer coefficient, the following parameter (g) shall be measured:

(g) process fluid flow rate

Other relevant parameters may be measured to reduce the total uncertainty in the calculated result.

6.7 Temperature Difference Monitoring Method

6.7.1 Objective. The objective of the temperature difference monitoring method is to provide an indication of thermal performance degradation of a heat exchanger over time by monitoring the relationship between the temperature of interest and the inlet temperature of the cooling fluid.

6.7.2 Descriptive Summary. In certain applications, where the heat exchanger coolant temperatures fluctuate (e.g., due to seasonal fluctuations in cooling fluid temperature), an indication of heat exchanger thermal performance may be obtained by monitoring the temperature of interest and the exchanger cooling fluid inlet temperature. With accumulated operating experience, a correlation between these temperatures may be established that permits detection of changes in exchanger performance through comparison of results from successive tests.

After meeting the inclusion and exclusion criteria and measuring the required parameters, the temperature of interest and the cooling fluid inlet temperature are measured. Deviation of the measured temperature difference from that predicted by the correlation for the measured cooling fluid inlet temperature provides an indication of heat exchanger performance change. An example is presented in Nonmandatory Appendix C, para. C-7.

6.7.3 Inclusion Criteria. The temperature difference monitoring method shall be considered if

(a) the equipment loads and the process temperatures and flows that create the heat load of the heat exchanger of interest are of the same magnitude for each test in the series.

(b) heat load and flows can be repeatedly attained for each test in a series of tests.

(c) steady-state conditions (see para. 7.1) do exist.

6.7.4 Exclusion Criteria. If the degree of operating margin is known to be small (in which case one of the more rigorous "test" methods, combined with parameter trending, may be required), then temperature difference monitoring method shall not be considered.

6.7.5 Required Parameters. The following two parameters [paras. 6.7.5(a) and (b)] shall be measured to indirectly evaluate the heat exchanger thermal performance using the temperature difference monitoring method:

(a) cooling fluid inlet temperature
(b) temperature of interest

Other relevant parameters may be measured to reduce the total uncertainty in the calculated result.

6.8 Pressure Loss Monitoring Method

6.8.1 Objective. The objective of the pressure loss monitoring method is to monitor the pressure loss across a heat exchanger, corrected for flow conditions.

6.8.2 Descriptive Summary. After meeting the inclusion and exclusion criteria and measuring the required parameters, a methodology is applied (a typical example is presented in Nonmandatory Appendix C, para. C-8) that will result in the calculation of a pressure loss, corrected to the acceptance criteria flow rate, for comparison with an acceptance criteria at that same flow condition.

Increases in pressure loss observed in a trend can be used as an indicator of the onset of flow blockage and thus as an aid in determining inspection and cleaning frequencies (refer to para. 6.10 and Nonmandatory Appendix C, para. C-10). If the heat exchanger is of the plate and frame type, this method may be the most sensitive for monitoring performance.

Even if heat loads are available, when fouling rates are high, pressure loss monitoring may provide a simple way to monitor fouling without having to frequently perform heat-transfer analysis.

6.8.3 Inclusion Criteria. The pressure loss monitoring method shall be considered if

(a) the design basis specifies safety function (or acceptance criteria, see para. 9) explicitly in terms of pressure loss.

(b) the correlation between pressure loss and heat transfer is known.

(c) the fouling characteristics (see Nonmandatory Appendix B, para. B-11) are likely to create a flow restriction.

6.8.4 Exclusion Criteria. The pressure loss monitoring method shall not be considered if

(a) the heat exchanger fouling layer thickness is small so as to preclude pressure loss from providing a reliable indication of heat exchanger capability.

(b) the fluid being monitored is a liquid on the shell side of a heat exchanger.

(c) the degree of operating margin is known to be small (in which case one of the more rigorous "test" methods, combined with parameter trending, may be required).

(d) the flow rate on the tube side traverses flow regimes in going from the test flow rate to the acceptance criteria flow rate.

6.8.5 Required Parameters. The following two parameters [paras. 6.8.5(a) and (b)] shall be measured to indirectly evaluate the heat exchanger thermal performance using the pressure loss monitoring method:

(a) the monitored fluid flow rate

(b) the monitored fluid pressure loss

Other relevant parameters may be measured to reduce the total uncertainty in the calculated result.

6.9 Visual Inspection Monitoring Method

6.9.1 Objective. The objective of the visual inspection monitoring method is to determine the condition of the component in relation to its ability to transfer heat.

6.9.2 Descriptive Summary. This method assumes that the heat exchanger being inspected will perform its intended function if it is maintained within a preestablished acceptably clean condition. After meeting the inclusion and exclusion criteria and measuring the required parameters, the heat exchanger is inspected (typical inspection types and techniques are presented in Nonmandatory Appendix C, para. C-9) and the ability of the heat exchanger to meet its acceptance criteria is evaluated based on the as-found condition of the component.

The visual inspection monitoring method consists of visually inspecting the heat exchanger periodically, usually by disassembly, allowing access to the internals of the cooling fluid and process fluid sides. Also, corrective action (e.g., cleaning) or additional inspections (e.g., eddy current testing or other NDE to determine integrity) can be implemented based on the inspection results. The inspection interval can be adjusted, based on experience.

6.9.3 Inclusion Criteria. The visual inspection monitoring method shall be considered if

(a) it is not possible to test or monitor by one of the previously described methods.

(b) there is sufficient access to the heat exchanger, such that the evaluator is able to cover a representative sample of the heat exchanger surface on the side most likely to foul.

(c) it is understood by those doing the inspections that the thickness of many biofilm layers is significantly reduced when they are in a dry condition and the layers can appear deceptively thin during an inspection when in fact they may be significantly thicker in their normal wet condition. Even wet fouling layers of only a few thousandths of an inch can cause significant degradation in heat transfer. These thicknesses would become even more difficult to detect in their dry condition.

(d) a preestablished acceptably clean condition exists to which the "fouled" observation may be compared (since a visual inspection cannot quantitatively evaluate heat exchanger performance).

6.9.4 Exclusion Criteria. The visual inspection monitoring method shall not be considered if

(a) unacceptable fouling would not be readily detectable by visual inspection (i.e., biofilms or very low allowable fouling resistances).

(b) the degree of operating margin is known to be small (in which case one of the more rigorous "test" methods, combined with parameter trending, may be required).

6.9.5 Required Parameters. Although no specific parameters are required for the inspection monitoring method, some inspection techniques may monitor certain parameters. For a discussion of typical inspection types and techniques, refer to Nonmandatory Appendix C, para. C-9.

6.10 Parameter Trending

6.10.1 Objective. The objective of parameter trending is to provide a systematic method for tracking heat exchanger performance over time and to provide a tool for predicting the need for remedial action.

Parameter trending shall be used to help establish appropriate intervals and acceptance criteria, and to supplement the testing and monitoring methods described in paras. 6.1 through 6.9.

6.10.2 Descriptive Summary. Parameter trending uses the results from one or more of the test or monitoring methods described in paras. 6.1 through 6.9. In addition, other parameters may be trended. The measured or calculated heat exchanger performance parameters are trended to determine a projected rate of performance degradation (see Fig. 1). The time to the next required corrective action, and changes in the rate of performance degradation that may indicate the onset of operational problems, may be readily detected through parameter trending.

After selecting the parameters to be trended (see Nonmandatory Appendix C, para. C-10) and trending these parameters for a minimum of three test or monitoring points, the trended parameters are compared to the applicable acceptance criteria (refer to para. 9 and Fig. 1). Typical trendable parameters are presented in Nonmandatory Appendix C, para. C-10.

7 TESTING AND MONITORING CONDITIONS

7.1 Steady State

Steady state as defined here is applicable to the following test and monitoring methods:

(a) functional test method using inequality (1) below

(b) heat-transfer coefficient test method without phase change using inequalities (1) through (3) below *(c)* heat-transfer coefficient test method with condensation using inequalities (1) through (3) below, but expressed in terms of enthalpy

(d) temperature effectiveness test method using inequality (1) below

(e) temperature difference monitoring method using inequality (1) below

For all other test and monitoring methods, steady state is not required.

Flows and temperatures should be held constant throughout the duration of the test to minimize precision errors (see para. 8.1.2), to minimize errors associated with sensor response times, and to allow the heat exchanger time to reach steady-state conditions.

A steady state exists when the transient part of the heat duty is very small when compared to the total heat duty defined as

$$\left[\sum_i (M_i)(C_i)\right][(\Delta T_{ave})/(\Delta\tau)] \ll Q \tag{1}$$

and the fluid flow on both the cooling fluid and process fluid sides has reached a steadiness defined as

$$[T_1 - T_2][\Delta(WC)_{shell}] \ll Q \tag{2}$$

$$[t_1 - t_2][\Delta(WC)_{tube}] \ll Q \tag{3}$$

CAUTION: The application of time independent analysis techniques (i.e., steady-state methods) to time dependent (i.e., transient) conditions will result in invalid analyses. If steady-state conditions cannot be achieved or adequately determined, an alternative testing or monitoring method should be considered.

NOTE: The variation in the total heat duty should be sufficiently small to ensure that steady-state conditions exist for a given application. Experience has shown that variation in total heat duty of 3.0% or less, when applied to eqs. (1) through (3), will result in conditions that adequately approximate steady state for current analytical models. Determining the rate of change of T_{ave} for variation in the total heat duty does not require the use of highly accurate instruments. Statistical techniques may be used to evaluate the difference between a series of points over time. This evaluation of the difference will negate the bias inherent to the instrument string being employed (see NOTE in Nonmandatory Appendix C, para. C-11.1.1). The precision required to meet accuracies of 3.0% or less in the total heat duty can then be achieved by increasing the number of data sets taken (see Nonmandatory Appendix C, para. C-11.1.2).

These inequalities must be continuously satisfied for a time period greater than $\tau 1$,

where

C_i = specific heat of material of i^{th} energy storage element, Btu/lbm-°F

M_i = mass of i^{th} energy storage element (i.e., tubes, shell, water) in the heat exchanger, lbm

Q = minimum of average bulk heat transfer rate calculated using the following two steady-state formulas, Btu/sec:

$$Q = |(WC)_{shell}(T_1 - T_2)|$$
$$Q = |(WC)_{tube}(t_1 - t_2)|$$

T_1 = shell-side inlet temperature during time period $\tau 1$, °F

t_1 = tube-side inlet temperature during time period $\tau 1$, °F

T_2 = shell-side outlet temperature during time period $\tau 1$, °F

t_2 = tube-side outlet temperature during time period $\tau 1$, °F

T_{ave} = instantaneous average of both inlet and both outlet temperatures, °F; if only three temperatures are measured then the fourth temperature should be calculated using the steady-state equations

$(WC)_{shell,\ min}$ = minimum value of the product of the shell-side mass flow rate and specific heat during time interval $\tau 1$

$(WC)_{tube,\ min}$ = minimum value of the product of the tube-side mass flow rate and specific heat during time interval $\tau 1$

ΔT_{ave} = change in T_{ave} over $\Delta\tau$ time, °F

$\Delta(WC)_{shell}$ = change in the product of shell-side mass flow rate and specific heat during time interval $\Delta\tau$, Btu/°F-sec

$\Delta(WC)_{tube}$ = change in the product of tube-side mass flow rate and specific heat during time interval $\Delta\tau$, Btu/°F-sec

$\Delta\tau$ = time interval between successive data points, sec

$\tau 1$ = ten times the maximum value of either of the following in sec:

$$\sum_i [M_iC_i/(WC)_{shell,\ min}]$$

$$\sum_i [M_iC_i/(WC)_{tube,\ min}]$$

NOTE: The above is not applicable to situations where either fluid is undergoing a phase change.

7.2 Flow Regimes

The flow regime(s) present on both the tube and the shell side of the heat exchanger under evaluation shall be identified, during both the test and the design accident conditions.

When going from test to design accident conditions, traversal of flow regimes is acceptable, except when specifically limited or prohibited by the exclusion criteria for a specific testing or monitoring method.

If traversal of flow regimes does occur, the additional uncertainty introduced by applying the required corrections shall be properly accounted for.

CAUTION: The uncertainty associated with traversal of flow regimes on the shell side is much greater than the uncertainty associated with traversal of flow regimes on the tube side. This may significantly affect the overall accuracy of the calculated value for the thermal performance of the heat exchanger.

7.3 Temperatures

Testing shall be conducted at temperatures as close to design accident conditions as practicable to minimize the errors introduced by changes in fluid properties when extrapolating from test to design accident conditions.

8 ERRORS, SENSITIVITIES, AND UNCERTAINTIES

Statistical methods shall be employed to ensure that both measurement errors and result sensitivities are considered when calculating the total uncertainty of any test or monitoring result. Measurement errors associated with measurement parameters used as equation inputs shall be propagated through the equation to determine the sensitivity of each measurement parameter on the test or monitoring result and to determine the total uncertainty of the test or monitoring result.

The total uncertainty shall be determined every time a test or monitoring is performed, because the total uncertainty will depend significantly upon the heat load available during the test and the cleanliness of the heat exchanger during the test. In fact, the cleaner the heat exchanger is, the more sensitive the test result will be to errors in the measurement parameters. This is primarily because of the reduction in terminal temperature differences associated with a clean heat exchanger, making those differences (and thus the LMTD) more sensitive to errors in their individual temperatures.

A 95% confidence level shall be applied to the calculated result for the purpose of comparing the testing or monitoring results to the acceptance criteria. Based on the heat exchanger design values and the plant design requirements for each heat exchanger function, a "required action limit" for corrective actions shall be established (see para. 9.3 and Fig. 1).

A standard statistical method for calculating the total uncertainty in the result is presented in Nonmandatory Appendix C, para. C-11. More sophisticated statistical methods may be used, which use additional effects (i.e., nonsymmetrical error, calculational bias, and redundant measurements), to improve the accuracy of the result, provided these methods are technically justifiable.

NOTE: If the total uncertainty of the test or monitoring result is determined to be too great to allow for meaningful results (i.e., the total uncertainty is greater than the available margin), then either:

(a) measurement errors should be decreased as outlined in para. 8.1 and Nonmandatory Appendix C, para. C-11, or

(b) whatever actions are necessary should be taken to increase the available margin.

8.1 Measurement Errors

Instrumentation accuracies used for testing and monitoring shall be such that, for each method selected, the determination of measurement errors, in conjunction with the result sensitivities, allows corrective actions to be performed so as to maintain heat exchanger operational readiness at all times. The measurement error consists of bias (fixed), precision (random), and spatial errors. A conventional method for calculating measurement errors is summarized in Nonmandatory Appendix C, para. C-11.

The following considerations shall be addressed to minimize measurement errors:

(a) selection, calibration, and placement of instruments (see Nonmandatory Appendix C, para. C-11)

(b) test and monitoring conditions (see para. 7)

(c) instrument response times, transport delay times, and other factors (see Nonmandatory Appendices A and B)

8.2 Result Sensitivities

Result sensitivities refers to how the previously discussed measurement errors are propagated through the calculational process. These sensitivities will be influenced by the test or monitoring method selected. There are two basic methods for determining result sensitivities: analytically and numerically. Due to the complexity of calculating the partial derivatives of a heat exchanger test result (e.g., fouling factor) with respect to each of the measurement parameters (i.e., the analytical method), the numerical method is the preferred method for this application. This method (sometimes called the "numerical perturbation" method) is summarized in Nonmandatory Appendix C, para. C-11.

8.3 Total Uncertainty

Total uncertainty refers to how the previously discussed result sensitivities are combined to arrive at a total uncertainty for the test or monitoring result. This total uncertainty will be influenced by the test or monitoring method selected. A method for determining the total uncertainty is summarized in Nonmandatory Appendix C, para. C-11.

8.4 Calculations and Averaging

All measured parameters shall be collected (sampled) at the same time, for each test interval, to minimize errors associated with variations in test conditions that might occur during the test. After collecting the appropriate number of data sets (see Nonmandatory Appendix C, para. C-11.1.2) and after rejecting any inconsistent data, each parameter shall be averaged. The test result shall then be calculated based on these average values.

To minimize error propagation through the remainder of the calculations, if additional, nonrequired parameters are able to be measured (see para. 6), the total uncertainty in the result should be calculated using both the measured and the calculated value of each parameter. A typical approach is summarized in Nonmandatory Appendix C, para. C-11.4.

8.5 Validity Check

The additional, nonrequired parameters may also be used as a validity check for the method being used (see para. 6).

For example, for the heat-transfer coefficient test method (without phase change), although measurement of only five of the six parameters is required (the sixth parameter being calculated), the sixth parameter may also be measured to provide a means for validating the test by comparing the calculated value of the sixth parameter to the measured value of that same parameter. If the sixth parameter is measured, and if the calculated value does not agree with the measured value, then the difference shall be reconciled (see Nonmandatory Appendix A for potential causes).

As another example, for the heat-transfer coefficient test method (with condensation), although measurement of only one of the steam-air mixture relative humidity parameters is required, it is recommended that both relative humidity parameters be measured to provide a means for validating the test by comparison with the other relative humidity parameter.

Additional parameters may be measured, in excess of the required parameters, if desired, to use as additional validity checks.

8.6 Correlational Uncertainty

Additional uncertainty may be introduced into the test result due to the uncertainty associated with the empirical correlations used for heat-transfer film coefficients (i.e., the correlational uncertainty, typically 15% to 20%). This is especially true if the flow on the shell side traverses flow regimes in going from the test condition to the design accident condition. However, if heat-transfer coefficients are calculated using the backcalculation method, then this uncertainty is significantly reduced. This is because any uncertainty in the correlation-based heat-transfer coefficients is corrected by the manufacturer by using an experience-based correction factor to develop the design rated duty of the heat exchanger (which reflects the heat exchanger's true performance). When this duty is used to backcalculate the heat-transfer coefficient, it will include this correction factor and, thus, more accurately reflect the true value of the heat-transfer coefficient.

9 ACCEPTANCE CRITERIA

Acceptance criteria consists of the following three types of limits:

(a) system operability limits
(b) component design limits
(c) required action limits (see Fig. 1 and para. 2 for definitions)

9.1 System Operability Limits

System operability limits shall be established for each heat exchanger, in accordance with the Safety Analysis Report, safety evaluation requirements, or other design calculations.

System operability limits shall be used to establish required action limits (see para. 9.3).

Examples of system operability limits are as follows:

(a) a requirement that a prescribed amount of heat must be transferred by some combination of heat exchangers under several operating conditions

(b) a requirement that pressure loss must be maintained below a certain value at a given flow rate to ensure adequate performance

(c) a requirement (based on the intended safety function) that the temperature of a component (e.g., a bearing temperature) or an enclosed space (e.g., a pump room) being serviced by a heat exchanger be maintained below a set temperature under accident conditions

9.2 Component Design Limits

Component design limits shall be identified for each heat exchanger, in accordance with the heat exchanger specification sheet, the heat exchanger design data sheet, or other similar component design specification. This as-designed heat exchanger data should be verified to correspond to the as-built heat exchanger.

Component design limits shall be used to indicate component degradation that, although not exceeding the system operability limits, may nonetheless be of concern from a component reliability standpoint.

NOTE: System operability limits may allow either more or less component degradation than component design limits. When the system operability limits allow more component degradation than the component design limits (as depicted in Fig. 1), while system operability may not be threatened, component reliability couldbe threatened (refer to Nonmandatory Appendix B, para. B-12). When the system operability limits allow less component degradation than the component design limits, the component design limits will serve no useful function for inservice testing (for preservice testing, see below). While no action is required for exceeding component design limits, corrective action should be taken at the next available opportunity to ensure continued component reliability.

Component design limits shall also be used during preservice testing to confirm that the component is or is not performing according to the component design limit.

Examples of component design limits are as follows:

(a) a requirement that a single heat exchanger was designed to transfer a specific amount of heat

(b) a requirement that a single heat exchanger was designed for operating with a specified pressure drop

9.3 Required Action Limits

Required action limits shall be established for each heat exchanger to allow corrective action to be taken prior to exceeding the system operability limit. Required action limits are based on the known fouling (or other degradation) rate, as determined by parameter trending (see para. 6.10), after applying a 95% confidence level to the data. This 95% confidence level is determined based on the total uncertainty calculated for the test or monitoring result (see para. 8 and Fig. 1).

Required action limits shall be used to ensure heat exchanger operational readiness throughout the entire interval of testing or monitoring (see para. 5.4).

10 CORRECTIVE ACTION

Corrective action (flushing, mechanical cleaning, chemical cleaning, mechanical repair, etc.) shall be performed following failure to meet the acceptance criteria as defined in para. 9, or whenever I(test) exceeds I(max), as described in Fig. 1. As part of this corrective action, the root cause of the failure should be determined (see Nonmandatory Appendix A).

Unless the effectiveness of the corrective action has been documented to be consistently repeatable, then following the corrective action, the heat exchanger should be retested or remonitored.

Following the corrective action, the heat exchanger shall, as a minimum, be evaluated to ensure the intended results of the corrective action have been accomplished.

NOTE: This evaluation involves examining and judging the performance of, and need not involve testing or monitoring. However, if the corrective action involved cleaning the shell side of the heat exchanger, then the heat exchanger should be retested or remonitored due to the possibility that fouling or cleaning materials (or both) may have been redistributed within the shell, or on the outside of the tubes, during the cleaning process (instead of being removed). Also, if the potential exists for debris (either fouling or maintenance related) to get trapped against a tube sheet following the cleaning process, or following upstream maintenance, then the heat exchanger should be retested or remonitored following that cleaning or maintenance.

Retesting or remonitoring after corrective action may also be necessary to establish a new baseline if the corrective action changes the mechanical characteristics (and thus the heat-transfer characteristics) of the heat exchanger (i.e., tube material changes, tube sleeving, and baffle modifications).

In addition to evaluation of the heat exchanger receiving the corrective action, evaluation of other heat exchangers may be required. If the fouling (or degradation) mechanism responsible for the first failure was the "normal" or "expected" mechanism, and if it occurred at the "normal" or "expected" rate, then no further evaluation is required. If, however, the mechanism for fouling (or degradation) is discovered to be of a different nature than expected, or if the fouling (or degradation) occurred more rapidly than expected, then other heat exchangers should be evaluated according to the following priority:

(a) Evaluate those heat exchangers that are known to have the least margin.

(b) Evaluate those heat exchangers that are likely to have been subject to the same fouling (or degradation) mechanism.

(c) Evaluate those heat exchangers that are next on the existing schedule.

11 RECORDS AND RECORD KEEPING

11.1 Equipment Records

A record shall be maintained that contains the following information for each heat exchanger covered here:

(a) the manufacturer's name

(b) the manufacturer's as-built design heat exchanger specification sheet(s)

(c) the manufacturer's as-built design drawings

(d) the manufacturer's acceptance test report, if available

(e) preservice test results, if available

(f) the date the equipment was initially placed in service

11.2 Plans and Procedures

A record shall be maintained of plans and procedures for tests, monitoring, and inspections that shall include the following:

(a) identification of the heat exchangers selected

(b) identification of the method selected for each heat exchanger and a justification for each method selected[3]

(c) identification of the interval selected for each heat exchanger and a justification for each interval selected

11.3 Record of Results

A record shall be maintained of the results for each test, monitoring, or inspection performed to allow for proper evaluation and trending of results. This record shall be maintained for the life of the plant or for the life of the component (whichever is less). This record shall include the following:

(a) identification of the heat exchanger

(b) date of the test, monitoring, or inspection

(c) reason for the test, monitoring, or inspection (e.g., periodic test, periodic maintenance, postmaintenance test)

(d) a complete set of test data, monitoring data, and inspection observations for the "as-found" conditions before any corrective actions (per the requirements of para. 5)

[3] For methods where inclusion and exclusion criteria are met and the method is not selected (i.e., the uncertainty of the method turns out to be greater than the available margin), a written justification for nonselection is required.

(e) a complete set of test data, monitoring data, and inspection observations for the "as-left" conditions following any corrective actions (subject to the exceptions as noted in paras. 5 and 10)

(f) identification of calibrated instruments used

(g) a complete record of the test result uncertainty analysis

(h) identification of the acceptance criteria used

(i) comparison of the results to the acceptance criteria

11.4 Record of Corrective Action

Records shall be maintained of corrective action, which shall include the following:

(a) a summary of corrective actions taken, including dates

(b) subsequent testing, monitoring, or inspections performed

PART 21
NONMANDATORY APPENDIX A
Diagnostics

This Appendix provides general guidelines to assist in identifying potential causes of abnormal or unexpected performance, as may be indicated by the testing or monitoring methods carried out in accordance with the provisions of Part 21.

Three types of potential inadequacies may be indicated as follows:

(a) heat duty deficiency
(b) excessive pressure loss
(c) mechanical dysfunction

A-1 HEAT DUTY DEFICIENCY

Thermal performance degradation of the heat exchanger below its design point may be due to actual deterioration in the heat exchanger's heat duty due to cooling fluid side fouling, process fluid side fouling, and/or mechanical dysfunction. Degradation may also be indicated due to errors caused by improper application of the methods outlined in Part 21 (e.g., testing errors and/or computational errors).

A-1.1 Cooling Fluid Side Fouling

The most common reason for actual decline in heat exchanger performance is fouling beyond the design point for the heat-transfer surfaces. In most cases, the fouling occurs on the cooling fluid side of the heat exchanger.

A-1.2 Process Fluid Side Fouling

If cleaning of the cooling fluid side does not restore performance, then the possibility of fouling on the process fluid side of the heat exchanger should be investigated. This is best achieved by performing a heat-transfer test following a thorough cleaning on the cooling fluid side. If the performance is still short of design by more than the design fouling resistance, then process fluid side fouling could be occurring.

A-1.3 Mechanical Dysfunction

If thermal performance degradation is not attributable to fouling, then the possibility of mechanical dysfunction should be investigated (see para. A-3).

A-1.4 Testing Errors

Potential error or oversight in testing should be carefully scrutinized whenever discrepancies between the test results and expected heat exchanger performance occur. Some typical examples of causes of errors in testing of heat exchangers are presented below.

(a) The instrumentation is imprecise, faulty, or inadequate. The demand on the level of required instrument accuracy depends on the temperature approach in the heat exchanger under the test conditions. The test engineer should establish the instrument accuracy level requirements and establish that the selected or available instrumentation is adequate. The measurement of vital data (i.e., flow rates and terminal temperatures) should have, insofar as possible, redundancy to provide a means of double-checking key data. Additional measurements (i.e., of intermediate fluid temperature between two shell or tube passes) can also provide useful information to identify performance deficiencies. For pressure measurements, deposits on or around the sensing element or pressure tap may result in significant error.

(b) The heat load for the test is inadequate. This is closely tied to errors, sensitivities, and uncertainties, as discussed in Part 21. Heat loads that might not otherwise be available during testing can be provided by scheduling testing (when possible) during plant cool-down for decay heat coolers, during heatup and recirculation of water in the borated (refueling) water storage tank for containment spray heat exchangers, by using reactor building temperature during startup for containment coolers, using spent fuel pool heat, using supplemental heaters, as well as other methods. When using supplemental heaters, it is necessary to ensure that adequate mixing of the heated air is occurring.

(c) The flow rates selected for testing result in severe temperature cross (a condition where the cold fluid outlet temperature exceeds the hot fluid outlet temperature) such that the heat exchanger performance is insensitive to large oscillations in flows.

(d) Testing is performed without complete vent-off of the noncondensibles. Trapped air (i.e., an air pocket) may render a portion of the tube bundle ineffective during the test.

(e) The heat exchanger is not allowed to reach steady-state conditions before test data collection is begun (for those methods where steady state is part of the inclusion criteria).

A-1.5 Computational Errors

Computational errors arise from improper mathematical analysis of the test data. Some examples of incorrect analysis are presented below.

(a) The tube- or shell-side flow rate during the testing condition is sufficiently low so as to produce laminar conditions in all or part of the tube bundle while the mathematical analysis uses turbulent flow correlations.

(b) Fouling on the tube surfaces has occurred unevenly in different tube passes while the mathematical analysis assumes uniform fouling deposition.

(c) Extensive plugging of tubes in one or two passes has caused gross inequalities in the number of tubes in the different passes while the mathematical analysis considers equal number of tubes in each tube pass.

(d) The header design of the heat exchanger produces appreciable flow maldistribution among the tubes while the analysis assumes uniformly distributed flow.

(e) The baffle configuration is not appropriately modeled.

A-2 EXCESSIVE PRESSURE LOSS

Measurement of pressure loss is an important way to obtain heat exchanger performance characteristics that are not so easily derived from thermal data alone. Pressure loss is discussed below in terms of tube side, shell side, and in plate heat exchangers.

A-2.1 Tube-Side Pressure Loss

Excessive tube-side pressure loss is almost always an indicator of a large accumulation of foreign matter (macrofouling) in the tubes, or on the tube sheet, leading to flow blockage and roughening of the tube inner surface. Moderate pressure loss may be the result of biological fouling (or other microfouling) of the tube inner surface (see Nonmandatory Appendix B, para. B-11).

A-2.2 Shell-Side Pressure Loss

Excessive shell-side pressure loss generally originates from flow blockage, although the blockage mechanism may be more complex. Clearances between the baffles and the shell ID, and between the tubes and baffle holes, contribute to the reduction of the overall shell-side pressure loss by diverting some of the flow into the leakage and bypass streams. Deposition of corrosion products in these narrow passages may alter the flow field in the heat exchanger, resulting in an increased portion of the shell-side flow in crossflow, causing an increase in pressure loss as well as an increase in heat transfer.

A-2.3 Plate Heat Exchanger Pressure Loss

Excessive pressure loss in plate heat exchangers generally originates from flow blockage, although it can also originate from fouling of the plate surfaces (see Nonmandatory Appendix B, para. B-10).

A-3 MECHANICAL DYSFUNCTION

If flushing or cleaning does not restore performance, then the possibility that mechanical dysfunction may be causing the performance degradation should be investigated. In most cases, mechanical dysfunction is intrinisic to the design and/or manufacture of the heat exchanger. In certain limited instances it is possible to modify the heat exchanger to eliminate or minimize the effects of such dysfunctions. These dysfunctions may include, but are not limited to, those described below.

A-3.1 Tube Vibration

Over a period of time, steel baffles in certain heat exchangers may corrode, resulting in enlargement of baffle holes. An enlarged baffle hole enables the tube to vibrate with a larger amplitude. The effect of this vibration on the heat-transfer rate is small when in the turbulent regime. However, under laminar conditions, tube mechanical vibration may cause a change in flow regimes, and thus alter the shell-side film coefficient.

Another reason for tube vibration is inadequate baffle spacing for the shell-side flows. This problem usually reveals itself during initial operation of the heat exchanger. Additional staking (the process of inserting a "stake" between adjacent tube rows to limit tube displacement under dynamic conditions) may be required to prevent collisions between adjacent tubes by limiting movement at the center of the unsupported tube span.

In a properly designed heat exchanger, tube vibration usually does not occur unless the shell-side flow is greater than twice the design flow. If a heat exchanger has tube vibration with laminar flow, then something is seriously wrong with the heat exchanger.

A-3.2 Interfluid Leakage

Massive tube leaks may cause errors in pressure measurements, affecting the accuracy of the methods that rely on pressure, and the conclusions drawn from them. For example, a tube leak could cause the corrected pressure loss to be low (normally a good indication) when in fact the performance of the heat exchanger is degraded (due to the tube leak).

Another path for interfluid leakage is at the tube-to-tube sheet interface. Often a very small leakage path in this area will increase in size due to the high ΔP between the tube side and the shell side. This will result in a "worm hole," which will allow leakage between the tube and shell sides.

Because plate-type heat exchangers are especially sensitive to flow and pressure loss, leakage between plates can significantly affect the accuracy of results.

A-3.3 Air In-Leakage

Inlet air in-leakage on ducted air coolers could cause erroneous test results. If the air in-leakage is downstream of where the air flow is being measured, the actual air flow across the coil will not be accurately measured. Likewise, if air temperature is being measured upstream of where the air in-leakage is, the inlet air temperature may not be accurately measured, especially if the air in-leakage temperature is significantly different than the ducted air temperature. If test results for the ducted air cooler appear erroneous, inlet air in-leakage should be considered, located, and quantified.

A-3.4 Internal Bypass Flow

Although less common than fouling as a cause for performance degradation, internal bypass flow may occur in both tube and shell sides, and its effect on reducing the heat duty may be quite considerable [see references in Part 21, paras. 3.2(a) and (b)]. Furthermore, the corrected pressure loss may indicate low (normally a good indication), when, in fact, the condition of the heat exchanger is significantly degraded due to the bypass flow. Internal bypass flow often results in temperature stratification of the outlet fluids due to inadequate mixing and/or nonuniform heating of the fluid. This may significantly affect the accuracy of the measured outlet fluid temperatures (refer to Nonmandatory Appendix B, para. B-3).

Changes in internal bypass flow may occur in heat exchangers due to the following:

(a) internal deformations caused by shop or system pressure testing of the equipment; typical of such a situation is the bowing of the unstayed (U-tube) tube sheet when the heat exchanger is hydrotested.

(b) internal deformations due to improper construction, fluid impingement forces, and/or excessive thermal strain. Typical of such a situation is the failure (either damaged or missing) of a pass partition plate gasket due to excessive flow excursions, which results in significant shell-side flow bypassing the tube bundle. Another example is deformation of pass partition plates in the channels of certain types of heat exchangers (e.g., TEMA types A and C) due to high differential pressures caused by tube blockage, resulting in tube-side bypass flow.

(c) misinstallation or wear of longitudinal baffle seal strips (used in certain removable bundle TEMA type F or G shells).

PART 21
NONMANDATORY APPENDIX B
Precautions

Some precautionary measures to avoid misinterpretation of test data and to prevent damage to the equipment during testing are presented below.

B-1 EXCESSIVE FLOW

Testing the heat exchanger at a shell-side flow rate that exceeds the design flow rate should not be done unless the tubes are determined to be safe from flow-induced vibration (refer to Part 11 for additional discussion).

Testing the heat exchanger at tube-side flow rates that exceed the design point may not present a serious problem as long as the testing is of limited duration.

Excessive flow rates may occur when performing flow balance testing of the system.

When heat exchangers are designed for series or parallel operation or when pumps operate in parallel, there exists the potential for operating a heat exchanger in excess of its allowable flow. The flow rates may increase to a point that will cause malfunction or damage to the operating unit. Listed below are three situations that can result in an overload or an abnormal operating mode as a result of flow conditions.

(a) removing a heat exchanger from service that is designed for parallel flow operation without throttling flow to the heat exchanger remaining in service

(b) removing a heat exchanger from service that is designed for series flow operation without adjusting the flow rates to the heat exchanger remaining in service

(c) operating a heat exchanger with increased pumping capacity; for example, with three half-capacity cooling water pumps operating in parallel

If the design limits are exceeded, accelerated erosion and failure may occur. There are no definitive guidelines presently available that can adequately determine the relationship of erosion to length of time at overload or abnormal operating conditions.

B-2 CROSSING FLOW REGIMES

If laminar flow is assumed, care should be taken to ensure that vibration around the heat exchanger does not cause the laminar flow to transition to turbulent flow.

If turbulent flow is assumed, then the only method that will allow for the extrapolation of test data from laminar to turbulent flow is the heat-transfer method.

It should be noted that reducing flow rates below the design flow rates (to increase temperature differences and, thus, to increase test accuracy) will require extrapolation back to the original design conditions. The reduced flow rates may also prevent the heat exchanger from achieving steady-state conditions.

When using one of the heat-transfer coefficient test methods, the heat exchanger should be tested at a sufficient number of shell-side flow rates to allow multiple shell-side film coefficients to be backcalculated from the preservice test data. This will allow extrapolation of the shell-side film coefficient at any future inservice test shell-side flow rate.

B-3 TEMPERATURE STRATIFICATION

Temperature stratification may occur whenever thermal streams within a fluid are not adequately mixed. Since many of the test thermowells provided by system designers are located directly on the outlets of the heat exchangers, where thermal streams are likely to exist and where adequate mixing is not likely to occur, most temperature stratification problems occur in measuring *outlet* fluid temperatures. This problem can be minimized by intentionally mixing the thermal streams, and then taking the temperature measurement *downstream* from where the mixing occurs. Mixing can be achieved by allowing the outlet fluid to pass through at least two pipe bends or through a discharge valve prior to measurement. If this or other measures are not possible, then provisions should be made to install at least two temperature sensors, 90 deg apart, and then average the readings.

When *laminar* flow is assumed, there is the increased possibility of having temperature stratification.

B-4 OVERCOOLING

Maintaining turbulent flow for the duration of the test (to keep the correlations valid) could result in overcooling systems served by the heat exchanger. This is especially true if the heat exchanger is operating at a reduced heat load for testing and/or if the test occurs during a period of cold cooling water temperatures.

B-5 FLASHING

Flashing of the cooling or process fluid may occur if there is a loss of static pressure in the fluid system. This situation should be evaluated not only for the test condition but also for the design accident condition to ensure that the flashing will not restrict the required flow of the fluid.

Flashing will result in misleading fluid temperatures, since the latent heat going into flashing will lower the fluid temperature toward saturation.

Flashing will also invalidate many of the methods described in Part 21, since the correlations used assume that flashing is not occurring.

B-6 EFFECTIVE SURFACE AREA

When evaluating heat exchanger performance using the heat-transfer method, any deliberate tube plugging (including those plugged during initial service) should be considered by removing the effective surface area of the plugged tubes from the total effective surface area. The reduction in the number of tubes available for flow will increase velocity through the remaining tubes and, hence, increase the inside film coefficient, h_i. While these two effects will tend to offset each other, they must still be taken into account to ensure an accurate evaluation of the overall heat-transfer coefficient and the total heat duty.

If "enhanced tubes" (i.e., tubes with internal or external fins) are used in the heat exchanger, then the effective surface area due to these enhancements must be properly accounted for (i.e., accounting for the area on *both* sides of a finned surface).

When evaluating heat exchanger performance using the pressure loss method, tube plugging will result in a higher differential pressure across the heat exchanger for a given flow rate. Thus, tube plugging must be accounted for here as well.

B-7 WATERHAMMER

In establishing system alignment and conditions for testing, precautions should be taken to prevent the occurrence of waterhammers.

B-8 MISCELLANEOUS CONSIDERATIONS

While the criteria for selection of methods (as presented in Part 21) should, in general, be followed, there may be special circumstances that call for a deviation from these criteria. Such circumstances may include, but are not limited to, the following:

(a) if the selected method would result in a greater safety risk than an alternate method

(b) if the selected method would result in a greater radiation exposure than an alternate method

(c) if the selected method would result in unacceptable safety system unavailability

Where radiation exposure is a concern, consideration should be given to performing one overall test of a pair or group of heat exchangers together, as one larger heat exchanger, to minimize exposure to test personnel.

B-9 FLOW INSTABILITY

Flow instability (oscillations) must be avoided.

B-10 PLATE HEAT EXCHANGERS

While Part 21 primarily addresses shell and tube heat exchangers (as shell and tube heat exchangers currently dominate most safety-related applications), Part 21 has been written to be applicable to "plate and frame" or "plate" heat exchangers as well. However, due to the significant differences between these two types of heat exchangers, caution should be exercised when applying Part 21 to plate heat exchangers. In many instances, the manufacturer will need to be solicited for specific design parameters and constants (which are often considered proprietary) before applying Part 21 to plate heat exchangers.

Some additional precautions are described below.

B-10.1 Torque Requirements

If plate heat exchangers are being used, it is critical that the manufacturer's recommendation be followed for tightening torque when assembling the plates. Failure to do so may result in leaking gaskets and decreased performance.

B-10.2 Flow Stability

Plate heat exchanger pressure losses are very sensitive to changes in flow. Thus, flow stability becomes even more important for plate heat exchangers when using the pressure-loss monitoring method.

B-11 FOULING CHARACTERISTICS

The type of fouling present in the heat exchanger can significantly affect the test and/or monitoring results. If the fouling layer creates a *smooth* constriction (as is typical of scaling deposits), then extremely low changes in pressure loss are associated with fouling levels that can cause significant degraded heat transfer. If, however, the fouling layer creates a *rough* constriction (as is typical of most biofilms) or results in tube plugging at the inlet tube sheet, then the pressure loss can be significantly higher than that calculated due to smooth constriction and may serve as a very good indicator of fouling due to blockage.

B-12 COMPONENT DESIGN FUNCTION

Although Part 21 is written to ensure that heat exchangers meet their "safety function," it is also important to compare results to the heat exchanger "design function." This is important because of the "margin" that may exist between the "safety" performance point and the "design" performance point. For example, cleaning a heat exchanger that has margin to the point of meeting its safety performance point may still leave some residual fouling on the tubes that could later result in tube pitting. Thus, comparing results to the safety function of the heat exchanger is important to ensure operational readiness, but this should not exclude comparing results to the design function of the heat exchanger to ensure reliability.

B-13 THERMAL DELAYS

Errors, in addition to the bias and precision errors discussed in para. 8 of Part 21, may be introduced into testing by the following thermal delays:

(a) Temperature Measurement Transient Response. The difference between the actual fluid temperature and the indicated fluid temperature due to the thermal inertia of the measuring device (e.g., thermal delays due to the thermal resistance of piping, if using surface-mounted temperature sensors, or due to the thermal resistance of thermowells and air spaces, if using thermowells).

(b) Temperature Measurement External Transport Timeshift. The difference between actual fluid temperature and indicated fluid temperature due to the fluid transport delay time between the heat exchanger and the location of the temperature-measuring device, external to the heat exchanger.

(c) Temperature Measurement Internal Transport Timeshift. The change in fluid outlet temperature in response to a change in fluid inlet temperature, prior to establishing a new steady state and due to the transport delay time of the fluid passing through the heat exchanger.

These thermal delays should be properly accounted for to minimize additional errors. By properly applying the testing and monitoring conditions as outlined in Part 21, para. 7 (e.g., achieving steady-state test conditions), these additional errors can be minimized.

B-14 MATERIAL PROPERTIES

Where heat exchanger tube (or plate) material has been changed from a copper alloy to a stainless steel alloy, biological fouling may be experienced even though it may not have been experienced with the copper alloy. This is because copper alloys create a toxic film that tends to retard biological growth.

PART 21
NONMANDATORY APPENDIX C
Examples

This Appendix provides examples to demonstrate simplified application of the methods described in Part 21. Paragraph 3.2 provides additional references that may be used if more complex application of the methods is required.

C-1 FUNCTIONAL TEST METHOD

The methodology used in the following example involves determining the temperature of interest (in this case, containment spray pump bearing temperatures), and then comparing it with the acceptance criteria (in this case, the pump manufacturer's maximum allowed temperature). The test is performed with the cooling system (in this case, component cooling water, or CCW) placed in a simulated design accident condition.

As demonstrated by the following example, the functional test method is ideally suited for heat exchangers on a closed cooling loop system, as the temperature of the closed cooling loop can be more easily manipulated than that of an open cooling loop.

C-1.1 Establish Cooling Water Maximum Design Conditions

The CCW system is allowed to climb to and stabilize at its 130°F design temperature by reducing the service water flow through the CCW heat exchanger.

C-1.2 Establish Flow

The CCW flow through the bearing coolers is brought to the design point via system alignment, but the flow need not be measured.

C-1.3 Establish Temperature of Interest Design Conditions

The containment spray pump is then operated and the two pump-bearing temperatures reach steady-state values of 143°F and 145°F.

C-1.4 Compare the Temperature of Interest to the Acceptance Criteria

If both of these temperatures are below the pump manufacturer's maximum allowed value of 158°F, then the bearing coolers are operable.

C-2 HEAT TRANSFER COEFFICIENT TEST METHOD (WITHOUT PHASE CHANGE)

The heat transfer coefficient test method (without phase change) is used to determine the heat transfer capability of the heat exchanger. The heat transfer capability may be calculated in terms of either of the two following quantities, Q_p and r_t:

(a) Q_p (the projected heat duty at design accident conditions). Q_d (the required heat duty at design accident conditions) would represent the "system operability limit" and would be used to develop the "required action limit" for the acceptance criteria (see para. 9).

(b) r_t (the total fouling resistance at the test conditions). r_d (the total fouling resistance specified at design accident conditions) would represent the "system operability limit" and would be used to develop the "required action limit" for the acceptance criteria (see para. 9).

In terms of the equations that follow,

$$r_t = r_{o,t}(1/E_f) + r_{i,t}(A_{o,t}/A_{i,t})$$

and

$$r_d = r_{o,d}(1/E_f) + r_{i,d}(A_{o,d}/A_{i,d})$$

where (dropping the subscripts "t" for "test conditions" and "d" for "design accident conditions")

A_i = inside effective surface area, ft^2, based on inside surface area, including any fin area

A_o = total effective surface area, ft^2, based on outside surface area, including any fin area

A_o/A_i = ratio of total-to-inside effective surface area (dimensionless)

E_f = weighted fin efficiency (dimensionless, equal to 1 for nonfinned tubes, less than 1 for finned tubes)

r = total fouling resistance, hr-ft^2-°F/Btu, based on outside surface area

r_i = inside fouling resistance, hr-ft^2-°F/Btu, based on inside surface area

r_o = outside fouling resistance, hr-ft^2-°F/Btu, based on outside surface area

For the heat transfer coefficient test method (without phase change), first, the design film coefficients are calculated using the mean temperature difference (MTD) method and backcalculation. Then, the performance under test conditions is evaluated using either the MTD method or the NTU method. Finally, the projected heat transfer rate (Q_p) of a heat exchanger under design accident (emergency) conditions is determined, given the current fouling level measured under test conditions.

The methodology used in the example below can be applied to any heat exchanger, with the exception of coil-tube heat exchangers.

The example is for a decay heat cooler that is a shell-and-tube heat exchanger with the process fluid on the shell side and the cooling fluid on the tube side. The heat exchanger is designed as a counterflow type with one shell pass and two tube passes.

This is a relatively simple example that assumes that no tubes are plugged and there is an equal number of tubes in each tube pass. The relationship for the log mean temperature difference correction factor can be easily solved and is well documented in the literature.

The data set given in para. C-2.1 is taken from the design accident conditions and is used to backcalculate the outside film coefficient, based on outside surface area, at design accident conditions. The data set given in para. C-2.2 is taken from the test point and is used to project the heat duty at design accident conditions by using the ratio method to calculate the outside film coefficient, based on outside surface area, at the test conditions and solving for the total fouling resistance at the test conditions.

In the example below, the cooling fluid flow rate is the same at the test and design accident conditions; however, the cooling and process fluid inlet temperatures and the process fluid flow rate at the test conditions are less than their corresponding values at the design accident conditions.

C-2.1 Evaluation at Design Accident Conditions (MTD Method)

C-2.1.1 Calculate *$LMTD_d$*. For parallel flow

$$LMTD_d = \frac{(T_{1,d} - t_{1,d}) - (T_{2,d} - t_{2,d})}{\ln[(T_{1,d} - t_{1,d})/(T_{2,d} - t_{2,d})]}$$

For true counterflow

$$LMTD_d = \frac{(T_{1,d} - t_{2,d}) - (T_{2,d} - t_{1,d})}{\ln[(T_{1,d} - t_{2,d})/(T_{2,d} - t_{1,d})]}$$

where

$LMTD_d$ = log mean temperature difference, °F, at design accident conditions
$T_{1,d}$ = process fluid inlet temperature, °F, at design accident conditions
$t_{1,d}$ = cooling fluid inlet temperature, °F, at design accident conditions
$T_{2,d}$ = process fluid outlet temperature, °F, at design accident conditions
$t_{2,d}$ = cooling fluid outlet temperature, °F, at design accident conditions

C-2.1.1.1 Data Set (for a Counterflow Heat Exchanger)

$LMTD_d$ = 43.65
$T_{1,d}$ = 140.0
$t_{1,d}$ = 75.0
$T_{2,d}$ = 119.3
$t_{2,d}$ = 97.0

C-2.1.2 Calculate *MTD_d*

$$MTD_d = (LMTD_d)(F_d)$$

where

F_d = $LMTD$ correction factor (dimensionless), to adjust for deviations from true counterflow, at design accident conditions (equals 1 for true counterflow and parallel flow)
$LMTD_d$ = log mean temperature difference, °F, at design accident conditions
MTD_d = mean temperature difference, °F, at design accident conditions

F_d is a function of R_d and P_d and can be obtained from Figs. B-1 through B-9 of the reference given in para. 3.1(b) or Figs. T-3.2A through T-3.2M of the reference in para. 3.1(a).

$$R_d = (T_{1,d} - T_{2,d})/(t_{2,d} - t_{1,d})$$
$$P_d = (t_{2,d} - t_{1,d})/(T_{1,d} - t_{1,d})$$

where

P_d = temperature effectiveness (dimensionless) at design accident conditions
R_d = capacity rate ratio (dimensionless) at design accident conditions
$T_{1,d}$ = process fluid inlet temperature, °F, at design accident conditions
$t_{1,d}$ = cooling fluid inlet temperature, °F, at design accident conditions
$T_{2,d}$ = process fluid outlet temperature, °F, at design accident conditions
$t_{2,d}$ = cooling fluid outlet temperature, °F, at design accident conditions

NOTE: For F correction factor curves that are available for split-flow, divided-flow, and cross-flow heat exchangers, T_1 and T_2 shall be for the shell side fluid and t_1 and t_2 shall be for the tube side fluid.

C-2.1.2.1 Data Set (for a Counterflow Heat Exchanger)

F_d = 0.9588
P_d = $(t_{2,d} - t_{1,d})/(T_{1,d} - t_{1,d})$
= (97.0 − 75)/(140.0 − 75)
= 0.3385
R_d = $(T_{1,d} - T_{2,d})/(t_{2,d} - t_{1,d})$
= (140.0 − 119.3)/(97.0 − 75.0)
= 0.9409

$$T_{1,d} = 140.0$$
$$t_{1,d} = 75.0$$
$$T_{2,d} = 119.3$$
$$t_{2,d} = 97.0$$

This result (specifically for a one-shell pass, two-tube pass flow arrangement) can be obtained in either of the following ways:

(a) by reading the number from Fig. B-1 of the reference in para. 3.1(b)

(b) by calculating the number from the following equation (the subscript "*d*" has been dropped for simplicity):

For $R = 1$

$$F = [(R^2 + 1)^{1/2}/(R - 1)]\{\ln[(1 - P)/(1 - PR)]/$$
$$\ln(\{2 - P[R + 1 - (R^2 + 1)^{1/2}]\}/$$
$$\{2 - P[R + 1 + (R^2 + 1)^{1/2}]\})\}$$

For $R = 1$

$$F = [P/(1 - P)](2^{1/2}/\ln\{[2 - P(2 - 2^{1/2})]/[2 - P(2 + 2^{1/2})]\})$$

Additional equations are available for other flow arrangements, and can be found in the references in paras. 3.2(h) through (l).

$$LMTD_d = 43.65$$

$$MTD_d = 41.85$$

C-2.1.3 Calculate U_d

$$U_d = (Q_d)/(A_{o,d})(MTD_d)$$

where

$A_{o,d}$ = total effective surface area, ft^2, based on outside surface area, including any fin area, at design accident conditions, from design specification sheet

MTD_d = mean temperature difference, °F, at design accident conditions

Q_d = heat duty, Btu/hr, based on outside surface area, at design accident conditions, from design specification sheet

U_d = overall heat transfer coefficient, Btu/hr-ft^2-°F, based on outside surface area, at design accident conditions[1]

CAUTION: Plugged tubes, if not equally plugged in each tube pass, will result in an unequal number of tubes in passes, and thus violate the assumptions made in the *LMTD* correction factor charts. If this is the case, then computerized methods may need to be employed to accurately solve the problem. For the sake of this example, we are assuming no plugged tubes and equal tube passes.

NOTE: Refer to Nonmandatory Appendix B, para. B-6 for precautions related to effective surface areas.

C-2.1.3.1 Data Set (for a Counterflow Heat Exchanger)

$$A_{o,d} = 5080$$
$$MTD_d = 41.85$$
$$Q_d = 65{,}870{,}000$$
$$U_d = 309.8$$

C-2.1.4 Calculate r_w (for Backcalculating $h_{o,d}$). For bare tubes

$$r_w = (d_o/24k)\ \ln[d_o/(d_o - 2t)]$$

For integral circumferentially finned tubes

$$r_w = \frac{t[d_o + 2nz(d_o + z)]}{12k(d_o - t)}$$

For extended finned tubes

$$r_w = \frac{A_{o,d} d_o \ln[d_o/(d_o - 2t)]}{24k(A_{o,\text{tube}})}$$

where

$A_{o,d}$ = total effective surface area, ft^2, based on outside surface area, including any fin area, at design accident conditions, from design specification sheet

$A_{o,\text{tube}}$ = total bare tube surface area, ft^2, based on outside surface area, at design accident conditions

d_o = outside diameter of bare tube or root diameter of fin, in.

k = thermal conductivity of tube wall, Btu/hr-ft-°F, from the reference in para. 3.2(g)

n = number of fins per in.

r_w = tube wall resistance, hr-ft^2-°F/Btu, based on outside surface area, at design accident conditions

t = tube wall thickness, in.

z = fin height, in., from design specification sheet or drawings

C-2.1.4.1 Data Set (for a Counterflow Heat Exchanger)

$$d_o = 0.75$$
$$k = 8.754$$
$$n = \text{n/a (bare tubes)}$$
$$r_w = 0.0004999$$
$$t = 0.049$$
$$z = \text{n/a (bare tubes)}$$

C-2.1.5 Calculate Re_d (for Backcalculating $h_{o,d}$)

$$Re_d = (124 p_d V_d d_i)/\mu_d$$

[1] U_d may also be obtained from technical specifications and design specification sheets.

where

d_i = inside diameter of tube, in.

Re_d = Reynolds Number (dimensionless) of the tube side fluid at design accident conditions

V_d = tube velocity, ft/sec, based on flow rate and cross-sectional flow area, at design accident conditions

μ_d = bulk absolute viscosity, centipoise, of the tube side fluid at design accident conditions, from the reference in para. 3.2(f)

ρ_d = bulk density, lbm/ft^3, of the tube side fluid at design accident conditions, from the reference in para. 3.2(f)

C-2.1.5.1 Data Set (for a Counterflow Heat Exchanger)

d_i = 0.652

Re_d = 49,400 (definitely turbulent flow)

V_d = 7.83

μ_d = 0.7966

ρ_d = 62.16

C-2.1.6 Calculate Pr_d (for Backcalculating $h_{o,d}$)

$$Pr_d = (2.42Cp_d\mu_d)/k_d$$

where

Cp_d = specific heat, Btu/lbm-°F, of the tube side fluid at design accident conditions, from the reference in para. 3.2(e)

k_d = bulk thermal conductivity, Btu/hr-ft-°F, of the tube side fluid at design accident conditions, from the reference in para. 3.2(e)

Pr_d = Prandtl Number (dimensionless) of the tube side fluid at design accident conditions

μ_d = bulk absolute viscosity, centipoise, of the tube side fluid at design accident conditions, from the reference in para. 3.2(f)

C-2.1.6.1 Data Set (for a Counterflow Heat Exchanger)

Cp_d = 0.9982

k_d = 0.3556

Pr_d = 5.411

μ_d = 0.7966

C-2.1.7 Calculate $h_{i,d}$ (for Backcalculating $h_{o,d}$). For turbulent flow, $Re_d > 10{,}000$

$$h_{i,d} = 0.023(12k_d/d_i)(Re_d)^{0.8}(Pr_d)^{1/3}(\mu_d/\mu_{w,d})^{0.14}$$

For laminar flow, $Re_d < 2{,}100$

$$h_{i,d} = 1.86(12k_d/d_i)(Re_d)^{1/3}(Pr_d)^{1/3}(d_i/L)^{1/3}(\mu_d/\mu_{w,d})^{0.14}$$

where

d_i = inside diameter of tube, in.

$h_{i,d}$ = inside film coefficient, Btu/hr-ft^2-°F, based on inside surface area, at design accident conditions

k_d = bulk thermal conductivity, Btu/hr-ft-°F, of the tube side fluid at design accident conditions, from the reference in para. 3.2(e)

L = total length of tube, in., carrying flow, from design specification sheet or drawings

Pr_d = Prandtl Number (dimensionless) of the tube side fluid at design accident conditions

Re_d = Reynolds Number (dimensionless) of the tube side fluid at design accident conditions

μ_d = bulk absolute viscosity, centipoise, of the tube side fluid at design accident conditions, from the reference in para. 3.2(f)

$\mu_{w,d}$ = absolute viscosity, centipoise, of the tube side fluid at the tube wall temperature at design accident contitions, from the reference in para. 3.2(f)

C-2.1.7.1 Data Set (for a Counterflow Heat Exchanger)

d_i = 0.652

$h_{i,d}$ = 1503

k_d = 0.3556

L = n/a (turbulent flow)

Pr_d = 5.411

Re_d = 49,400

μ_d = 0.7966

$\mu_{w,d}$ = 0.7966 (use same value as μ_d for this temperature range)

C-2.1.8 Calculate E_f (for Backcalculating $h_{o,d}$)

$$E_f = 1 - [A_{\text{fin},d}/A_{o,d}][1 - \eta]$$

where

$A_{\text{fin},d}$ = total fin surface area, ft^2, at design accident conditions

$A_{o,d}$ = total effective surface area, ft^2, based on outside surface area, including any fin area, at design accident conditions, from design specification sheet

E_f = weighted average of efficiency of outside surface

η = fin efficiency

For efficiencies of fins around a single tube, the fin efficiency, η, may be calculated using Fig. C-4.1 in the reference in para. 3.2(d). If a fin is shared by more than one tube, the area associated with one tube may be calculated by dividing the fin sheet area by the number of tubes penetrating this fin.

$$d_{\text{fin}} = [(4A_{\text{sheet}}/n\pi) + d_o^2]^{1/2}$$

where

A_{sheet} = area of one side of multitube fin, in.^{2}

d_{fin} = equivalent diameter of a single tube fin, in.

d_o = outside diameter of bare tube, in.

n = number of tubes sharing single fin

This d_{fin}, along with other fin parameters, can be used to calculate fin efficiency, η.

$$(1/h_{\text{fin},d}) = (1/h_{o,d}) + r_{o,d}$$

where

$h_{\text{fin},d}$ = film coefficient of fin, Btu/hr-ft^2-°F, at design accident conditions

$h_{o,d}$ = outside film coefficient, Btu/hr-ft^2-°F, based on outside surface area, at design accident conditions

$r_{o,d}$ = outside fouling resistance, hr-ft^2-°F/Btu, based on outside surface area, assumed for design accident conditions, from design specification sheet

Since $h_{o,d}$ depends on E_f, and E_f depends on $h_{o,d}$, the solution is iterative.

C-2.1.9 Using the Values Calculated Above, Backcalculate $h_{o,d}$

$$U_d = 1/[r_{o,d}(1/E_f) + r_{i,d}(A_{o,d}/A_{i,d}) + (1/h_{o,d})(1/E_f) + r_w + (1/h_{i,d})(A_{o,d}/A_{i,d})]$$

which becomes

$$h_{o,d} = 1/E_f[(1/U_d) - (r_{o,d}/E_f) - r_{i,d}(A_{o,d}/A_{i,d}) - r_w - (1/h_{i,d})(A_{o,d}/A_{i,d})]$$

where

$A_{i,d}$ = inside effective surface area, ft^2, based on inside surface area, including any fin area, at design accident conditions

$A_{o,d}$ = total effective surface area, ft^2, based on outside surface area, including any fin area, at design accident conditions, from design specification sheet

$A_{o,d}/A_{i,d}$ = ratio of total to inside effective surface area (dimensionless) at design accident conditions

E_i = weighted fin efficiency (dimensionless, equal to 1 for nonfinned tubes, less than 1 for finned tubes)

$h_{i,d}$ = inside film coefficient, Btu/hr-ft^2-°F, based on inside surface area, at design accident conditions

$h_{o,d}$ = outside film coefficient, Btu/hr-ft^2-°F, based on outside surface area, at design accident conditions

$r_{i,d}$ = inside fouling resistance, hr-ft^2-°F/Btu, based on inside surface area, assumed for design accident conditions, from design specification sheet

$r_{o,d}$ = outside fouling resistance, hr-ft^2-°F/Btu, based on outside surface area, assumed for design accident conditions, from design specification sheet

r_w = tube wall resistance, hr-ft^2-°F/Btu, based on outside surface area, at design accident conditions

U_d = overall heat transfer coefficient, Btu/hr-ft^2-°F, based on outside surface area, at design accident conditions

If either $r_{i,d}$ or $r_{o,d}$ is not given, assume it is equal to zero.

CAUTION: The $h_{o,d}$ calculated by this method will be valid for the test condition only if the shell side test flow is maintained in the same flow regime as the shell side design flow, and only if phase conditions are the same for the test and design conditions. If these conditions cannot be met, then the direct calculation method (below) or a computerized method must be used.

C-2.1.9.1 Data Set (for a Counterflow Heat Exchanger)

$A_{o,d}/A_{i,d}$ = 1.15
E_f = 1.0
$h_{i,d}$ = 1503
$h_{o,d}$ = 2581
$r_{i,d}$ = 0.0005
$r_{o,d}$ = 0.001
r_w = 0.0004999
U_d = 309.8

C-2.1.10 Calculate $h_{o,d}$ (Direct Calculation Method).

Empirical relationships for h_o may be found in the literature that allows for direct calculation at different flow rates and for different configurations [for these relationships and direct calculation methods, refer to para. 3.2(m) and references therein].

C-2.1.10.1 Data Set (for a Counterflow Heat Exchanger)

$h_{o,d}$ = n/a (using backcalculation method)

C-2.2 Evaluation at Test Conditions

C-2.2.1 Collect the Test Data.

Record the following temperature and flow data at steady-state conditions. This set of data will be termed the test point. Only five of the six parameters are required (the sixth being calculated); however, for validity purposes (see para. 8.5) it is recommended that all six parameters be recorded.

$T_{1,t}$ = process fluid inlet temperature, °F, at test conditions

$t_{1,t}$ = cooling fluid inlet temperature, °F, at test conditions

$T_{2,t}$ = process fluid outlet temperature, °F, at test conditions

$t_{2,t}$ = cooling fluid outlet temperature, °F, at test conditions

$W_{c,t}$ = cooling fluid flow rate, lbm/hr, at test conditions

$W_{p,t}$ = process fluid flow rate, lbm/hr, at test conditions

C-2.2.1.1 Data Set (for a Counterflow Heat Exchanger)

$T_{1,t}$ = 120.0
$t_{1,t}$ = 60
$T_{2,t}$ = 97.5
$t_{2,t}$ = 78.7
$W_{c,t}$ = 3,000,000
$W_{p,t}$ = 2,500,000

C-2.2.2 Calculate Q_t (*MTD* Method). For process fluid

$$Q_{p,t} = W_{p,t}[Cp_{p,t}(T_{1,t} - T_{2,t})]$$

For cooling fluid

$$Q_{c,t} = W_{c,t}[Cp_{c,t}(t_{1,t} - t_{2,t})]$$

where

$Cp_{c,t}$ = bulk specific heat, Btu/lbm-°F, of the cooling fluid at test conditions, from the reference in para. 3.2(e)
$Cp_{p,t}$ = bulk specific heat, Btu/lbm-°F, of the process fluid at test conditions, from the reference in para. 3.2(e)
$Q_{c,t}$ = heat duty, Btu/hr, for the cooling fluid at test conditions
$Q_{p,t}$ = heat duty, Btu/hr, for the process fluid at test conditions
$T_{1,t}$ = process fluid inlet temperature, °F, at test conditions
$t_{1,t}$ = cooling fluid inlet temperature, °F, at test conditions
$T_{2,t}$ = process fluid outlet temperature, °F, at test conditions
$t_{2,t}$ = cooling fluid outlet temperature, °F, at test conditions
$W_{c,t}$ = cooling fluid flow rate, lbm/hr, at test conditions
$W_{p,t}$ = process fluid flow rate, lbm/hr, at test conditions

NOTE: Refer to para. C-11.4 for guidance on which of the above parameters should be measured and which should be calculated.

C-2.2.2.1 Data Set (for a Counterflow Heat Exchanger)

$Cp_{c,t}$ = 0.9988
Q_t = 56,030,000
$t_{1,t}$ = 60.0
$t_{2,t}$ = 78.7
$W_{c,t}$ = 3,000,000 (note that test was done at design flow rate)

C-2.2.3 Calculate $LMTD_t$ (*MTD* Method). For parallel flow

$$LMTD_t = \frac{(T_{1,t} - t_{1,t}) - (T_{2,t} - t_{2,t})}{\ln[(T_{1,t} - t_{1,t})/(T_{2,t} - t_{2,t})]}$$

For true counterflow

$$LMTD_t = \frac{(T_{1,t} - t_{2,t}) - (T_{2,t} - t_{1,t})}{\ln[(T_{1,t} - t_{2,t})/(T_{2,t} - t_{1,t})]}$$

where

$LMTD_t$ = log mean temperature difference, °F, at test conditions
$T_{1,t}$ = process fluid inlet temperature, °F, at test conditions
$t_{1,t}$ = cooling fluid inlet temperature, °F, at test conditions
$T_{2,t}$ = process fluid outlet temperature, °F, at test conditions
$t_{2,t}$ = cooling fluid outlet temperature, °F, at test conditions

C-2.2.3.1 Data Set (for a Counterflow Heat Exchanger)

$LMTD_t$ = 39.37
$T_{1,t}$ = 120
$t_{1,t}$ = 60
$T_{2,t}$ = 97.5
$t_{2,t}$ = 78.7

C-2.2.4 Calculate MTD_t (*MTD* Method)

$$MTD_t = (LMTD_t)(F_t)$$

where

F_t = *LMTD* correction factor (dimensionless), to adjust for deviations from true counterflow, at test conditions, equals 1 for true counterflow and parallel flow
$LMTD_t$ = log mean temperature difference, °F, at test conditions
MTD_t = mean temperature difference, °F, at test conditions

F_t is a function of R_t and P_t and can be obtained from Figs. B-1 through B-9 of the reference in para. 3.1(b) or Figs. T-3.2A through T-3.2M of the reference in para. 3.1(a).

$$R_t = (T_{1,t} - T_{2,t})/(t_{2,t} - t_{1,t})$$

$$P_t = (t_{2,t} - t_{1,t})/(T_{1,t} - t_{1,t})$$

where

P_t = temperature effectiveness (dimensionless) at test conditions
R_t = capacity rate ratio (dimensionless) at test conditions
$T_{1,t}$ = process fluid inlet temperature, °F, at test conditions
$t_{1,t}$ = cooling fluid inlet temperature, °F, at test conditions
$T_{2,t}$ = process fluid outlet temperature, °F, at test conditions

$t_{2,t}$ = cooling fluid outlet temperature, °F, at test conditions

NOTE: For F correction factor curves that are available for split-flow, divided-flow, and cross-flow heat exchangers, T_1 and T_2 shall be for the shell side fluid and t_1 and t_2 shall be for the tube side fluid.

C-2.2.4.1 Data Set (for a Counterflow Heat Exchanger)

F_t = 0.953
P_t = (78.7 − 60)/(120 − 60)
= 0.3117
R_t = (120 − 97.5)/(78.7 − 60)
= 1.203
$T_{1,t}$ = 120
$t_{1,t}$ = 60
$T_{2,t}$ = 97.5
$t_{2,t}$ = 78.7

This result (specifically for a one-shell pass, two-tube pass flow arrangement) can be obtained in either of the following ways:

(a) by reading the number from Fig. B-1 of the reference in para. 3.1(b)

(b) by calculating the number from the following equation (the subscript "t" has been dropped for simplicity)

For $R = 1$

$$F = [(R^2 + 1)^{1/2}/(R - 1)]\{\ln[(1 - P)/(1 - PR)]/ \ln(\{2 - P[R + 1 - (R^2 + 1)^{1/2}]\}/ \{2 - P[R + 1 + (R^2 + 1)^{1/2}]\})\}$$

For $R = 1$

$$F = [P/(1 - P)](2^{1/2}/\ln\{[2 - P(2 - 2^{1/2})]/ [2 - P(2 + 2^{1/2})]\})$$

Additional equations are available for other flow arrangements, and can be found in the references in paras. 3.2(h) through (l).

$LMTD_t$ = 39.37
MTD_t = 37.52

C-2.2.5 Calculate U_t (*MTD* Method)

$$U_t = (Q_t)/(A_{o,t})(MTD_t)$$

where

$A_{o,t}$ = total effective surface area, ft^2, based on outside surface area, including any fin area, and any reduction in area due to plugged tubes, at test conditions
MTD_t = mean temperature difference, °F, at test conditions
Q_t = heat duty, Btu/hr, at test conditions
U_t = overall heat transfer coefficient, Btu/hr-ft^2-°F, based on outside surface area, at test conditions

CAUTION: Plugged tubes, if not equally plugged in each tube pass, will result in an unequal number of tubes in passes, and thus violate the assumptions made in the *LMTD* correction factor charts. If this is the case, then computerized methods may need to be employed to accurately solve the problem. For the sake of this example, we are assuming no plugged tubes and equal tube passes.

C-2.2.5.1 Data Set (for a Counterflow Heat Exchanger)

$A_{o,t}$ = 5080 (note, there is no tube plugging accounted for here)
MTD_t = 37.52
Q_t = 56,030,000
U_t = 294.0

C-2.2.6 Calculate U_t (*NTU* Method)

$$U_t = (NTU_t)(W_{c,t})(Cp_{c,t})/A_{o,t}$$

where

$A_{o,t}$ = total effective surface area, ft^2, based on outside surface area, including any fin area, and any reduction in area due to plugged tubes, at test conditions
$Cp_{c,t}$ = bulk specific heat, Btu/lbm-°F, of cooling fluid at test conditions, from the reference in para. 3.2(e)
NTU_t = number of transfer units (dimensionless) at test conditions
U_t = overall heat transfer coefficient, Btu/hr-ft^2-°F, based on outside surface area, at test conditions
$W_{c,t}$ = cooling fluid flow rate, lbm/hr, at test conditions

NTU_t is a function of R_t and P_t, and can be obtained from Figs. B-10 through B-12 of the reference in para. 3.1(b) or Figs. T-3.3 through T-3.3B of the reference in para. 3.1(a).

$$R_t = (T_{1,t} - T_{2,t})/(t_{2,t} - t_{1,t})$$
$$P_t = (t_{2,i} - t_{1,t})/(T_{1,t} - t_{1,t})$$

where

P_t = thermal effectiveness (dimensionless) at test conditions
R_t = capacity rate ratio (dimensionless) at test conditions
$T_{1,t}$ = process fluid inlet temperature, °F, at test conditions
$t_{1,t}$ = cooling fluid inlet temperature, °F, at test conditions
$T_{2,t}$ = process fluid outlet temperature, °F, at test conditions

$t_{2,t}$ = cooling fluid outlet temperature, °F, at test conditions

NOTE: For *NTU* curves that are available for split-flow, divided-flow, and cross-flow heat exchangers, T_1 and T_2 shall be for the shell side fluid and t_1, t_2, $W_{c,t}$ and Cp_c shall be for the tube side fluid.

C-2.2.6.1 Data Set (for a Counterflow Heat Exchanger)

NTU_t = 0.5
P_t = (78.7 − 60)/(120 − 60)
= 0.3117
R_t = (120 − 97.5)/(78.8 − 60)
= 1.203
$T_{1,t}$ = 120
$t_{1,t}$ = 60
$T_{2,t}$ = 97.5
$t_{2,t}$ = 78.7

This result (specifically for a one-shell pass, two-tube pass flow arrangement) can be obtained in either of the following ways:

(a) by reading the number from Fig. B-12 of the reference in para. 3.1(b)

(b) by calculating the number from the following equations (the subscript "*t*" has been dropped for simplicity)

For $R = 0$ and $R =$ infinity

$$NTU = \ln[1/(1 - P)]$$

For $R = 0$ and $R =$ infinity

$$NTU = [1/(R^2 + 1)^{1/2}][\ln(\{2 - P[R + 1 - (R^2 + 1)^{1/2}]\}/\{2 - P[R + 1 + (R^2 + 1)^{1/2}]\})]$$

Additional equations are available for other flow arrangements, and can be found in the references in paras. 3.2(h) through (l).

$A_{o,t}$ = 5080
$Cp_{c,t}$ = 0.9988
U_t = 294.9
$W_{c,t}$ = 3,000,000

C-2.2.7 Calculate Re_t

$$Re_t = (124\rho_t V_t d_i)/\mu_t$$

where

d_i = inside diameter of tube, in.
Re_t = Reynolds Number (dimensionless) of the tube side fluid at test conditions
V_t = tube velocity, ft/sec, based on flow rate and cross-sectional flow area, at test conditions
μ_t = bulk absolute viscosity, centipoise, of the tube side fluid at test conditions, from the reference in para. 3.2(f)
ρ_t = bulk density, lbm/ft^3, of the tube side fluid at test conditions, from the reference in para. 3.2(f)

C-2.2.7.1 Data Set (for a Counterflow Heat Exchanger)

d_t = 0.652
Re_t = 39,900
V_t = 7.8
μ_t = 0.9847
ρ_t = 62.31

C-2.2.8 Calculate Pr_t

$$Pr_t = (2.42Cp_t\mu_t)/k_t$$

where

Cp_t = bulk specific heat, Btu/lbm-°F, of the tube side fluid at test conditions, from the reference in para. 3.2(e)
k_t = thermal conductivity, Btu/hr-ft-°F, of the tube side fluid, at test conditions, from the reference in para. 3.2(e)
Pr_t = Prandtl Number (dimensionless) of the tube side fluid at test conditions
μ_t = bulk absolute viscosity, centipoise, of the tube side fluid at test conditions, from the reference in para. 3.2(f)

C-2.2.8.1 Data Set (for a Counterflow Heat Exchanger)

Cp_t = 0.9988
k_t = 0.3474
Pr_t = 6.851
μ_t = 0.9847

C-2.2.9 Calculate $h_{i,t}$. For turbulent flow, $Re_t > 10{,}000$

$$h_{i,t} = 0.023(12k_t/d_i)(Re_t)^{0.8}(Pr_t)^{1/3}(\mu_t/\mu_{w,t})^{0.14}$$

For laminar flow, $Re_t < 2{,}100$

$$h_{i,t} = 1.86(12k_t/d_i)(Re_t)^{1/3}(Pr_t)^{1/3}(d_i/L)^{1/3}(\mu_t/\mu_{w,t})^{0.14}$$

where

d_i = inside diameter of tube, in.
$h_{i,t}$ = inside film coefficient, Btu/hr-ft^2-°F, based on inside surface area, at test conditions
k_t = bulk thermal conductivity, Btu/hr-ft-°F, of the tube side fluid, at test conditions, from the reference in para. 3.2(e)
L = total length of tube, in., carrying flow
Pr_t = Prandtl Number (dimensionless) of the tube side fluid at test conditions
Re_t = Reynolds Number (dimensionless) of the tube side fluid at test conditions

μ_t = bulk absolute viscosity, centipoise, of the tube side fluid at test conditions, from the reference in para. 3.2(f)

$\mu_{w,t}$ = absolute viscosity, centipoise, of the tube side fluid at the tube wall temperature, at test conditions, from the reference in para. 3.2(f)

C-2.2.9.1 Data Set (for a Counterflow Heat Exchanger)

d_i = 0.652
$h_{i,t}$ = 1339
k_t = 0.3474
L = n/a (turbulent flow)
Pr_t = 6.851
Re_t = 39,900
μ_t = 0.9847
$\mu_{w,t}$ = 0.9847 (use same value as μ_t for this temperature range)

C-2.2.10 Calculate $h_{o,t}$ (Ratio Method)

$$h_{o,t} = h_{o,d}(W_t/W_d)^{0.6}(\mu_t/\mu_d)^{-0.27}(Cp_t/Cp_d)^{1/3}(k_t/k_d)^{2/3}$$

where

Cp_d = bulk specific heat, Btu/lbm-°F, of the shell side fluid at design accident conditions, from the reference in para. 3.2(e)

Cp_t = bulk specific heat, Btu/lbm-°F, of the shell side fluid at test conditions, from the reference in para. 3.2(e)

$h_{o,d}$ = outside film coefficient, Btu/hr-ft^2-°F, based on outside surface area, at design accident conditions

$h_{o,t}$ = outside film coefficient, Btu/hr-ft^2-°F, based on outside surface area, at test conditions

k_d = bulk thermal conductivity, Btu/hr-ft-°F, of the shell side fluid at design accident conditions, from the reference in para. 3.2(e)

k_t = bulk thermal conductivity, Btu/hr-ft-°F, of the shell side fluid at test conditions, from the reference in para. 3.2(e)

W_d = flow rate, lbm/hr, of the shell side fluid at design accident conditions

W_t = flow rate, lbm/hr, of the shell side fluid at test conditions

μ_d = bulk absolute viscosity, centipoise, of the shell side fluid at design accident conditions, from the reference in para. 3.2(f)

μ_t = bulk absolute viscosity, centipoise, of the shell side fluid at test conditions, from the reference in para. 3.2(f)

C-2.2.10.1 Data Set (for a Counterflow Heat Exchanger)

Cp_d = 0.9990
Cp_t = 0.9985
$h_{o,d}$ = 2,581
$h_{o,t}$ = 2,081
k_d = 0.3730
k_t = 0.3653
W_d = 3,200,000
W_t = 2,500,000
μ_d = 0.5050
μ_t = 0.6146

CAUTION: **Although the variable subscripts used for calculating the outside film coefficient are the same as those used for calculating the inside film coefficient, the outside film coefficient variables relate to the shell side fluid and the inside film coefficient variables relate to the tube side fluid (as stated in the variable definitions above).**

C-2.2.11 Calculate $h_{o,t}$ (Direct Calculation Method). Empirical relationships for h_o may be found in the literature that allows for direct calculation at different flow rates and for different configurations [for these relationships and direct calculation methods, refer to para. 3.2(m) and references therein].

C-2.2.11.1 Data Set (for a Counterflow Heat Exchanger)

$h_{o,t}$ = n/a (using backcalculation method)

C-2.2.12 Calculate r_t. Using the values calculated above, solve the following equation for r_t:

$$U_t = \frac{1}{[r_t + (1/h_{o,t})(1/E_f) + r_w + (1/h_{i,t})(A_{o,t}/A_{i,t})]}$$

where

$A_{i,t}$ = inside effective surface area, ft^2, based on inside surface area, including any fin area, and any reduction in area due to plugged tubes, at test conditions

$A_{o,t}$ = total effective surface area, ft^2, based on outside surface area, including any fin area, and any reduction in area due to plugged tubes, at test conditions

$A_{o,t}/A_{i,t}$ = ratio of total to inside effective surface area (dimensionless) at test conditions

E_f = weighted fin efficiency (dimensionless, equal to 1 for nonfinned tubes, less than 1 for finned tubes)

$h_{i,t}$ = inside film coefficient, Btu/hr-ft^2-°F, based on inside surface area, at test conditions

$h_{o,t}$ = outside film coefficient, Btu/hr-ft^2-°F, based on outside surface area, at test conditions

$r_{i,t}$ = inside fouling resistance, hr-ft^2-°F/Btu, based on inside surface area, at test conditions[2]

$r_{o,t}$ = outside fouling resistance, hr-ft^2-°F/Btu, based on outside surface area, at test conditions[2]

r_t = total fouling resistance, hr-ft^2-°F/Btu, based on outside surface area, at test conditions

= $r_{o,t}(1/E_f) + r_{i,t}(A_{o,t}/A_{i,t})$

r_w = tube wall resistance, hr-ft^2-°F/Btu, based on outside surface area, at design accident conditions

U_t = overall heat transfer coefficient, Btu/hr-ft^2-°F, based on outside surface area, at test conditions

C-2.2.12.1 Data Set (for a Counterflow Heat Exchanger)

$A_{o,t}/A_{i,t}$ = 1.150
E_f = 1.0
$h_{i,t}$ = 1339
$h_{o,t}$ = 2081
r_t = 0.001562
r_w = 0.0004999
U_t = 294.0

C-2.3 Projection at Design Accident Conditions

C-2.3.1 Calculate U_p. Using the values calculated above, solve the following equation for U_p:

$$U_p = \frac{1}{[r_t + (1/h_{o,d})(1/E_f) + r_w + (1/h_{i,d})(A_{o,t}/A_{i,t})]}$$

where

$A_{i,t}$ = inside effective surface area, ft^2, based on inside surface area, including any fin area, and any reduction in area due to plugged tubes, at test conditions

$A_{o,t}$ = total effective surface area, ft^2, based on outside surface area, including any fin area, and any reduction in area due to plugged tubes, at test conditions

$A_{o,t}/A_{i,t}$ = ratio of total to inside effective sur-face area (dimensionless) at test conditions

E_f = weighted fin efficiency (dimensionless, equal to 1 for nonfinned tubes, less than 1 for finned tubes)

$h_{i,d}$ = inside film coefficient, Btu/hr-ft^2-°F, based on inside surface area, at design accident conditions

$h_{o,d}$ = outside film coefficient, Btu/hr-ft^2-°F, based on outside surface area, at design accident conditions

$r_{i,t}$ = inside fouling resistance, hr-ft^2-°F/Btu, based on inside surface area, at test conditions

$r_{o,t}$ = outside fouling resistance, hr-ft^2-°F/Btu, based on outside surface area, at test conditions

r_t = total fouling resistance, hr-ft^2-°F/Btu, based on outside surface area, at test conditions

= $r_{o,t(1}/E_f) + r_{i,t(}A_{o,t}/A_{i,t)}$

r_w = tube wall resistance, hr-ft^2-°F/Btu, based on outside surface area, at design accident conditions

U_p = overall heat transfer coefficient, Btu/hr-ft^2-°F, based on outside surface area, projected at design accident conditions based on fouling at test conditions

C-2.3.1.1 Data Set (for a Counterflow Heat Exchanger)

$A_{o,t}/A_{i,t}$ = 1.150
E_f = 1.0
$h_{i,d}$ = 1503
$h_{o,d}$ = 2581
r_t = 0.001562
r_w = 0.0004999
U_p = 311.1

C-2.3.2 Calculate Q_p. Using the values calculated above, solve the following equation for Q_p:

$$Q_p = (U_p)(A_{o,t})(MTD_d)$$

where

$A_{o,t}$ = total effective surface area, ft^2, based on outside surface area, including any fin area, and any reduction in area due to plugged tubes, at test conditions

MTD_d = mean temperature difference, °F, at design accident conditions
mean temperature difference, °F, at design accident conditions

Q_p = heat duty, Btu/hr, projected at design accident conditions based on fouling at test condition

U_p = overall heat transfer coefficient, Btu/hr-ft^2-°F, based on outside surface area, projected at design accident conditions based on fouling at test condition

C-2.3.2.1 Data Set (for a Counterflow Heat Exchanger)

$A_{o,t}$ = 5080
MTD_d = 41.85
Q_p = 66,140,000
U_p = 311.1

[2] Assume the design value (or zero) for either $r_{i,t}$ or $r_{o,t}$ (whichever one is not calculated).

C-3 HEAT TRANSFER COEFFICIENT TEST METHOD (WITH CONDENSATION)

When heat transfer occurs from a steam-air mixture (humid air), the sensible heat transfer takes place because of a temperature difference and the mass transfer occurs because of a difference in steam partial pressure across the convection layer. Heat is released during condensation (latent heat). This heat of condensation penetrates across the tube wall to the cooling fluid inside the tubes. The condensation rate is equal to the mass transfer rate.

Since the condensation rate strongly depends on the saturation pressure at the gas-condensate interface (which depends on the gas-condensate interface temperature), the heat transfer coefficient associated with the convection outside the tubes (and any fins) varies over the heat transfer surface. Also, the change in enthalpy of the steam-air mixture cannot be expressed as $mCp\Delta T$, and a closed form solution for F, or effectiveness, cannot be derived. Because of these two reasons, the heat transfer equations must be integrated numerically.

Basically, the procedure is to vary the fouling resistance until the calculated parameters match the measured parameters. The fouling resistance thus obtained is then used to calculate the heat transfer rate under the design accident conditions.

The methodology used in the following example can be applied to any heat exchanger, with the exception of coil-tube heat exchangers.

C-3.1 Collect the Test Data

Paragraph 6.3 describes the data needed for this test. Various combinations of data can be used. In this example, it has been assumed that the following data are available:

(a) process fluid (steam-air mixture) pressure
(b) cooling fluid inlet temperature
(c) cooling fluid outlet temperature
(d) process fluid (steam-air mixture) inlet temperature
(e) process fluid (steam-air mixture) outlet temperature
(f) cooling fluid flow rate
(g) process fluid (steam-air mixture) inlet relative humidity

C-3.2 Write the Finite Difference Equations

Write the finite difference equations of the heat transfer process. Equations (C-1) to (C-24) are shown here as a guide. These equations are for a cross-flow unmixed heat exchanger having only one tube row with fins on the outside. Figure C-1 shows this heat exchanger along with its j^{th} finite element bounded by two parallel planes in the y-z plane. The air flow is along the y direction. The water flow is along the x direction. The flow parameters along the z direction are uniform. The governing equations for more complex geometries having many tube rows and passes can be written in a similar fashion.

Figure C-2 shows a fin, condensate layer, and interface temperatures.

From the law of conservation of mass applied to the fluid outside the tubes in the j^{th} element of the heat exchanger, note the following:

$$W_{da}(\phi_{1,j} - \phi_{2,j}) = W_{\text{cond},j} \tag{C-1}$$

$$W_{da}(\phi_{1,j} - \phi_{2,j}) = M_A N_{A,j}\left(\frac{A}{b}\right) \tag{C-2}$$

$$\phi_{1,j} = \phi_{\text{in}};\ 1 \le j \le N$$

where

A = total outside heat transfer area, $\text{ft}^2 = A_{\text{fin}} + A_{t,\text{exp}}$ [see eq. (C-6)]
b = length of heat exchanger along water flow direction, ft
M_A = molecular weight of vapor, lbm/lbm-mole
$N_{A,j}$ = vapor mass transfer rate per unit outside area, lbm-mole/hr-ft^2, of j^{th} element of heat exchanger
$W_{\text{cond},j}$ = mass flow rate of condensate generated per unit length, lbm/hr-ft, along the direction of water flow of j^{th} element of heat exchanger
W_{da} = mass flow rate of dry air per unit length, lbm/hr-ft, along the direction of water flow
$\phi_{1,j}$ = vapor-to-dry air mass ratio upstream of tube row of j^{th} element of heat exchanger
$\phi_{2,j}$ = vapor-to-dry air mass ratio downstream of tube row of j^{th} element of heat exchanger
ϕ_{in} = vapor-to–dry air mass ratio at inlet

From the law of conservation of energy applied to the fluid outside the tubes in the j^{th} elements of the heat exchanger, note the following:

$$W_{da}(e_{1,j} - e_{2,j}) = U_j\left(\frac{A}{b}\right)\left[\frac{1}{2}(T_{\infty 1,j} + T_{\infty 2,j}) - T_{1,j}\right] + (W_{\text{cond},j})(e_{\text{cond},j}) \tag{C-3}$$

$$e_{1,j} = e_{in}$$

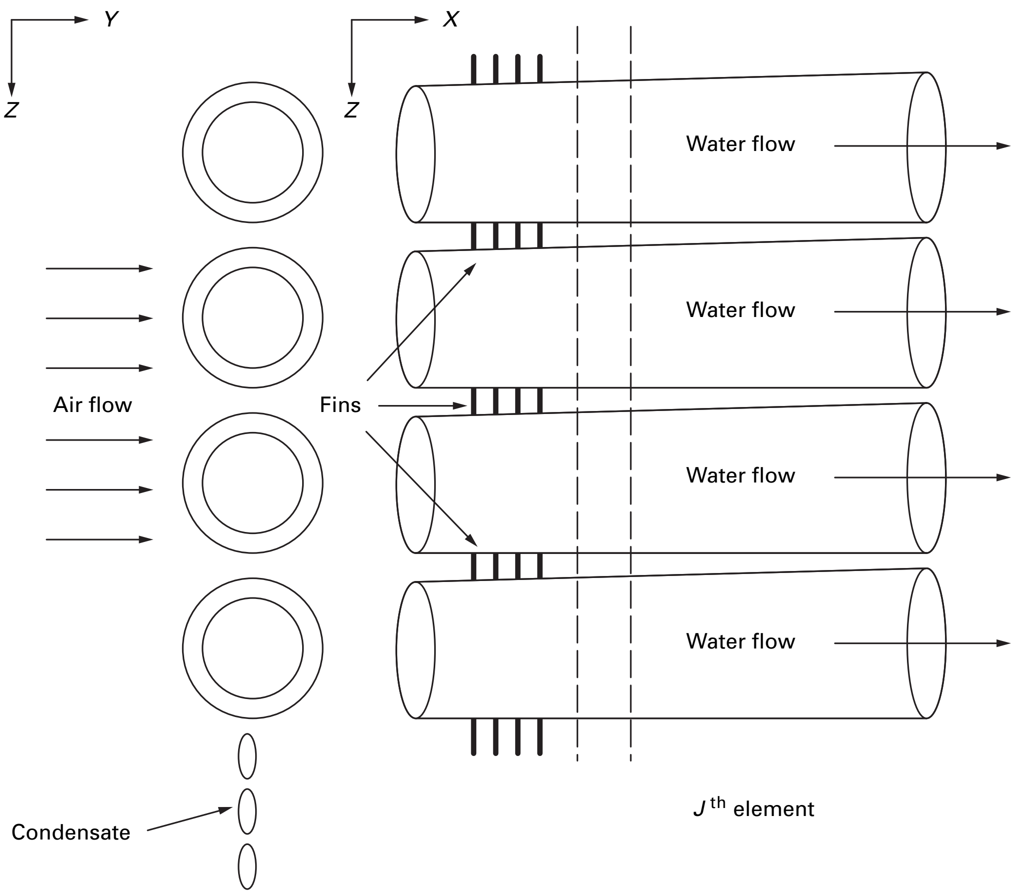
$$T_{\infty 1,j} = T_{\infty,\text{in}} \quad ; \quad 1 \le j \le N$$

$$e = f_1(\phi, T_\infty) \tag{C-4}$$

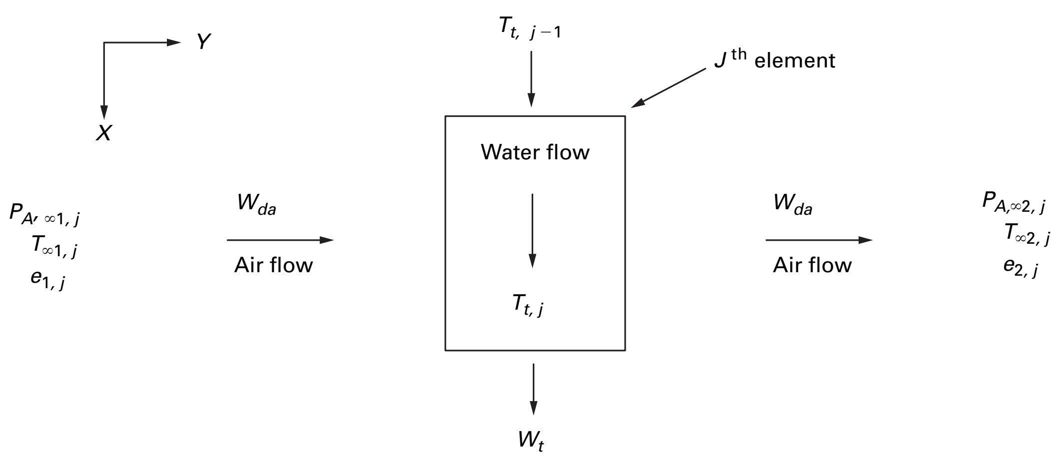
where

A = total outside heat transfer area, $\text{ft}^2 = A_{\text{fin}} + A_{t,\text{exp}}$ [see eq. (C-6)]
b = length of heat exchanger along water flow direction, ft

Fig. C-1 One Tube Row Air-to-Water Cross-Flow Heat Exchanger

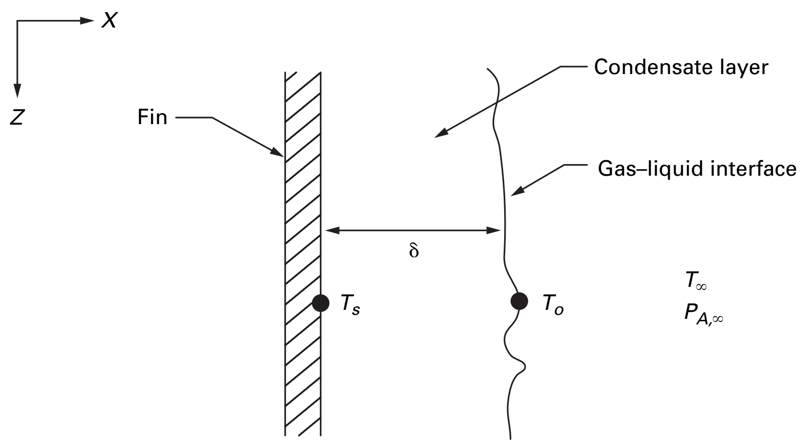


(a) Heat Exchanger and Fins



(b) J^{th} Element

Fig. C-2 Fin, Condensate Layer, and Interfaces



$e_{1,j}$ = enthalpy of air-vapor mixture, Btu/lbm of dry air, upstream of tube row of j^{th} element of the heat exchanger
$e_{2,j}$ = enthalpy of air-vapor mixture, Btu/lbm of dry air, downstream of tube row of j^{th} element of the heat exchanger
$e_{\text{cond},j}$ = enthalpy of the condensate, Btu/lbm, of j^{th} element of the heat exchanger
e_{in} = enthalpy of the air-vapor mixture, Btu/lbm *da*, at the inlet
f_1 = functional operator 1
T_∞ = temperature, °F, of air-vapor mixture
$T_{\infty 1,j}$ = temperature, °F, of air-vapor mixture upstream of the tube row of j^{th} element of the heat exchanger
$T_{\infty 2,j}$ = temperature, °F, of air-vapor mixture downstream of the tube row of j^{th} element of the heat exchanger
$T_{\infty,\text{in}}$ = temperature, °F, of air-vapor mixture at inlet
$T_{t,j}$ = tube side fluid temperature, °F, of j^{th} element of the heat exchanger
U_i = overall heat transfer coefficient, Btu/hr-ft^2-°F, of j^{th} element of the heat exchanger
$W_{\text{cond},j}$ = mass flow rate of condensate generated per unit length, lbm/hr-ft, along the direction of water flow of j^{th} element of heat exchanger
W_{da} = mass flow rate of dry air per unit length, lbm/hr-ft, along the direction of water flow
ϕ = vapor-to–dry air mass ratio

From the law of conservation of energy applied to the fluid inside the tubes in the j^{th} element of the heat exchanger, note the following:

$$(WCp)_t(T_{t,j} - T_{t,j-1}) = U_j(\Delta A)\left[\frac{1}{2}(T_{\infty 1,j} + T_{\infty 2,j}) - T_{t,j}\right] \quad \text{(C-5)}$$

$$1 \le j \le N$$

$$T_{t,0} = T_{t,\text{in}} \quad \text{and} \quad T_{t,\text{out}} = T_{t,N}$$

where

A = total outside heat transfer area, ft^2 = A_{fin} + $A_{t,\text{exp}}$ [see eq. (C-6)]
ΔA = area, ft^2, of a finite element of the heat exchanger (also total heat transfer area of the heat exchanger divided by the number of elements into which the heat exchanger has been subdivided) = A/N
N = number of elements into which the heat exchanger has been subdivided
$T_{\infty 1,j}$ = temperature, °F, of air-vapor mixture upstream of tube row of j^{th} element of the heat exchanger
$T_{\infty 2,j}$ = temperature, °F, of air-vapor mixture downstream of tube row of j^{th} element of the heat exchanger
$T_{t,\text{in}}$ = tube side fluid inlet temperature, °F
$T_{t,0}$ = tube side fluid temperature, °F, upstream of the first heat exchanger element
$T_{t,j}$ = tube side fluid temperature, °F, of j^{th} element of the heat exchanger
$T_{t,j\text{-}1}$ = tube side fluid temperature, °F, of $(j - 1)^{\text{th}}$ element of the heat exchanger
$T_{t,\text{out}}$ = tube side fluid outlet temperature, °F
U_j = overall heat transfer coefficient, Btu/hr-ft^2-°F, of j^{th} element of the heat exchanger
$(WCp)_t$ = product of the tube side flow rate and specific heat, Btu/hr-°F

The local heat transfer coefficient is a function of local temperature and vapor partial pressure and needs to be calculated simultaneously. To evalute the local overall heat transfer coefficient, the following equations can be established using the law of conservation of energy, various constitutive relationships, and definitions. The overall heat transfer coefficient can be expressed in terms of individual conductances as follows:

$$\frac{1}{U_j(A_{\text{fin}} + A_{t,\text{exp}})} = \frac{1}{h_{\text{fin},j}(\eta_j A_{\text{fin}} + A_{t,\text{exp}})} + \frac{d_o \ln(d_o/d_i)}{2k_{\text{wall}} A_o} + \frac{1}{A_i}\left(\frac{1}{h_i} + r_{fi}\right) \quad \text{(C-6)}$$

where
A_{fin} = surface area of the fins, ft^2
A_i = inside area of the tubes, ft^2
A_o = outside area of the tubes, ft^2
$A_{t,\text{exp}}$ = outside exposed area of tubes, ft^2; this is the area of the tubes that is in direct contact with the outside fluid
d_j = inside diameter of the tube, ft
d_o = outside diameter of the tube, ft
$h_{\text{fin},j}$ = heat transfer coefficient, Btu/hr-ft^2-°F, associated with the fin surface of j^{th} element of the heat exchanger
h_i = tube side heat transfer coefficient, Btu/hr-ft^2-°F
k_{wall} = thermal conductivity of the tube wall material, Btu/hr-ft-°F
r_{fi} = inside fouling resistance, hr-ft^2-°F/Btu
U_j = overall heat transfer coefficient, Btu/hr-ft^2-°F, of j^{th} element of the heat exchanger
η_j = fin efficiency (dimensionless) associated with the fin surface of j^{th} element of the heat exchanger

Since the heat flows from the outside fluid to the inside fluid via the condensate layer and the fins, one can write the following:

$$q_j = \frac{k_{\text{cond}}}{\delta_j}(T_{o,j} - T_{s,j}) \quad \text{(C-7)}$$

$$q_j = h_{\text{out},j}(T_{\infty,j} - T_{o,j}) \quad \text{(C-8)}$$

$$q_j = U_j(T_{\infty,j} - T_{t,j}) \quad \text{(C-9)}$$

where
$h_{\text{out},j}$ = outside heat transfer coefficient, Btu/hr-ft^2-°F, associated with simultaneous heat and mass transfer of j^{th} element of the heat exchanger
k_{cond} = bulk thermal conductivity of the condensate, Btu/hr-ft-°F
q_j = local heat transfer rate per unit outside area, Btu/hr-ft^2, of j^{th} element of the heat exchanger
$T_{\infty,j}$ = temperature, °F, of bulk fluid around the tubes of j^{th} element of the heat exchanger
$T_{o,j}$ = temperature of gas-condensate interface, °F, of j^{th} element of the heat exchanger
$T_{s,j}$ = local average temperature, °F, of outside heat transfer surface of j^{th} element of the heat exchanger
$T_{t,j}$ = tube side fluid temperature, °F, of j^{th} element of the heat exchanger
U_j = overall heat transfer coefficient, Btu/hr-ft^2-°F, of j^{th} element of the heat exchanger
δ_j = condensate layer thickness, ft, of j^{th} element of the heat exchanger

The local heat transfer rate per unit outside area is equal to the sum of convective heat transfer rate per unit area and the energy release rate per unit area associated with the condensation of vapor. Therefore,

$$q_j = h_j(T_{\infty,j} - T_{o,j}) + (N_{A,j})(h_{ig})(M_A) \quad \text{(C-10)}$$

and

$$T_{\infty,j} = \tfrac{1}{2}(T_{\infty 1,j} + T_{\infty 2,j}) \quad \text{(C-11)}$$

$$T_{\text{cond},j} = \tfrac{1}{2}(T_{o,j} + T_{s,j}) \quad \text{(C-12)}$$

where
h_{fg} = heat of condensation of the vapor, Btu/lbm
h_j = outside heat transfer coefficient, Btu/hr-ft^2-°F, of j^{th} element of the heat exchanger adjusted for high mass transfer rate associated with sensible heat transfer only
M_A = molecular weight of the vapor, lbm/lbm-mole
$N_{A,j}$ = vapor mass transfer rate per unit outside area, lbm-mole/hr-ft^2, of j^{th} element of the heat exchanger
q_j = local heat transfer rate per unit outside area, Btu/hr-ft^2, of j^{th} element of the heat exchanger
$T_{\text{cond},j}$ = condensate temperature, °F, of j^{th} element of the heat exchanger
$T_{\infty,j}$ = temperature, °F, of bulk fluid around the tubes of j^{th} element of the heat exchanger
$T_{\infty 1,j}$ = temperature, °F, of the air-vapor mixture upstream of the tube row of j^{th} element of the heat exchanger
$T_{\infty 2,j}$ = temperature, °F, of the air-vapor mixture downstream of the tube row of j^{th} element of the heat exchanger
$T_{o,j}$ = temperature of gas-condensate interface, °F, of j^{th} element of the heat exchanger
$T_{s,j}$ = local average temperature, °F, of outside heat transfer surface of j^{th} element of the heat exchanger

The mass transfer rate per unit outside area is related to vapor partial pressure difference by the mass transfer coefficient as follows:

$$N_{A,j} = k_{A,j} \ln\left(\frac{p_{\text{tot}} - p_{A,o,j}}{p_{\text{tot}} - p_{A,\infty j}}\right) \quad \text{(C-13)}$$

$$p_{A,\infty j} = \frac{1}{2}(p_{A,\infty 1,j} + p_{A,\infty 2,j}) \quad \text{(C-14)}$$

where

$k_{A,j}$ = mass transfer coefficient, lbm-mole/hr-ft^2, of j^{th} element of the heat exchanger not adjusted for high mass transfer rate

$N_{A,j}$ = vapor mass transfer rate per unit outside area, lbm-mole/hr-ft^2, of j^{th} element of the heat exchanger

$p_{A,\infty,j}$ = average vapor partial pressure, psia, in the bulk fluid of j^{th} element of the heat exchanger

$p_{A,\infty 1,j}$ = vapor partial pressure, psia, upstream of the tube row of j^{th} element of the heat exchanger

$p_{A,\infty 2,j}$ = vapor partial pressure, psia, downstream of the tube row of j^{th} element of the heat exchanger

$p_{A,o,j}$ = saturation pressure, psia, of the vapor at temperature T_o of j^{th} element of the heat exchanger

p_{tot} = pressure, psia, of the vapor-air mixture

The local convective heat transfer coefficient is altered by the local mass flux and is given as follows:

$$h_j = \frac{\mathrm{N}_{A,j}C_A}{1 - e^{-(N_{A,j}C_A/h_j)}} \tag{C-15}$$

where

C_A = molar specific heat, Btu/lbm-mole-°F, of pure vapor

h_j = outside heat transfer coefficient, Btu/hr-ft^2-°F, in noncondensing situation of j^{th} element of the heat exchanger

h_j = outside heat transfer coefficient, Btu/hr-ft^2-°F, of j^{th} element of the heat exchanger adjusted for high mass transfer rate associated with sensible heat transfer only

$N_{A,j}$ = vapor mass transfer rate per unit outside area, lbm-mole/hr-ft^2, of j^{th} element of the heat exchanger

Assuming that thermodynamic equilibrium exists at the gas-condensate interface, the vapor partial pressure at the interface is equal to the vapor pressure of the liquid at the interface temperature as follows:

$$p_{A,o,j} = p_{\text{sat}(T_{o,j})} \tag{C-16}$$

where

$p_{A,o,j}$ = partial pressure, psia, of the vapor at the gas-liquid interface of j^{th} element of the heat exchanger

$p_{\text{sat}(T_{o,j})}$ = saturation pressure, psia, of the vapor corresponding to $T_{o,j}$

$T_{o,j}$ = temperature of gas-condensate interface, °F, of j^{th} element of the heat exchanger

The relationship between vapor partial pressure and vapor mass fraction can be expressed as follows:

$$\phi_{1,j} = \frac{M_A}{M_{da}}\left(\frac{p_{A,\infty 1,j}}{p_{\text{tot}} - p_{A,\infty 1,j}}\right) \tag{C-17}$$

$$\phi_{2,j} = \frac{M_A}{M_{da}}\left(\frac{p_{A,\infty 2,j}}{p_{\text{tot}} - p_{A,\infty 2,j}}\right) \tag{C-18}$$

where

M_A = molecular weight of the vapor, lbm/lbm-mole

M_{da} = molecular weight of dry air, lbm/lbm-mole

$p_{A,\infty 1,j}$ = vapor partial pressure, psia, upstream of the tube row of j^{th} element of the heat exchanger

$p_{A,\infty 2,j}$ = vapor partial pressure, psia, downstream of the tube row of j^{th} element of the heat exchanger

p_{tot} = pressure, psia, of the vapor-air mixture

$\phi_{1,j}$ = vapor-to–dry air mass ratio of j^{th} element of heat exchanger upstream of tube row

$\phi_{2,j}$ = vapor-to–dry air mass ratio of j^{th} element of heat exchanger downstream of tube row

The heat transfer coefficient associated with the outside heat transfer surface can be expressed in terms of outside fouling resistance, condensate layer resistance, and the outside convective resistance. Therefore,

$$\frac{1}{h_{\text{fin},j}} = \frac{1}{h_{\text{out},j}} + r_{j,o} + \frac{\delta_j}{k_{\text{cond}}} \tag{C-19}$$

where

$h_{\text{fin},j}$ = heat transfer coefficient, Btu/hr-ft^2-°F, associated with the fin surface of j^{th} element of the heat exchanger

$h_{\text{out},j}$ = outside heat transfer coefficient, Btu/hr-ft^2-°F, associated with simultaneous heat and mass transfer of j^{th} element of the heat exchanger

k_{cond} = bulk thermal conductivity of the condensate, Btu/hr-ft-°F

$r_{f,o}$ = outside fouling resistance, hr-ft^2-°F/Btu

δ_j = condensate layer thickness, ft, of j^{th} element of the heat exchanger

Note, h_{fin} should be used to calculate fin efficiency (refer to para. C-2.1.8).

The condensate layer flows vertically downwards along the fin surface. Its thickness can be calculated using the following expression:

$$\delta_j = \frac{3}{4}\left[\frac{3\mu N_{A,j}M_A L}{\rho_1(\rho_1 - \rho_v)g}\right]^{1/3} \tag{C-20}$$

where

g = acceleration due to gravity, ft/hr^2

L = vertical length, ft, of fins over which condensate layer slides

M_A = molecular weight, lbm/lbm-mole, of the vapor

$N_{A,j}$ = vapor mass transfer rate per unit outside area, lbm-mole/hr-ft^2, of j^{th} element of the heat exchanger
δ_j = condensate layer thickness, ft, of j^{th} element of the heat exchanger
μ = viscosity, lbm /hr-ft, of the condensate
ρ_1 = density, lbm/ft^3, of the condensate
ρ_v = density, lbm/ft^3, of the air-vapor mixture

The mass transfer coefficient can be evaluated using the analogy between heat transfer and mass transfer. This relationship is as follows:

$$k_A = \frac{h}{C}\left(\frac{Pr}{Sc}\right)^{2/3} \tag{C-21}$$

where
C = molar specific heat, Btu/lbm-mole-°F, of the air-vapor mixture
h = outside heat transfer coefficient, Btu/hr-ft^2-°F, in noncondensing situation
k_A = mass transfer coefficient, lbm-mole/hr-ft^2, not adjusted for high mass transfer rate
Pr = Prandtl Number of the air-vapor mixture (dimensionless)
Sc = Schmidt Number of the air-vapor mixture (dimensionless)

It is clear from the above equations that the humid air outlet enthalpy and vapor-mass fraction are functions of the distance from the vapor inlet, "x." The mixed mean outlet temperature of the humid air can be related to the mixed mean values of outlet enthalpy and vapor mass fraction. The expressions of humid air mixed mean outlet enthalpy and vapor mass fraction are as follows:

$$e_{\text{out}} = \frac{1}{N}\sum_{j=1}^{N} e_{2,j} \tag{C-22}$$

$$\phi_{\text{out}} = \frac{1}{N}\sum_{j=1}^{N} \phi_{2,j} \tag{C-23}$$

where
$e_{2,j}$ = enthalpy, Btu/lbm of dry air, of the air-vapor mixture downstream of the tube row of j^{th} element of the heat exchanger
e_{out} = enthalpy, Btu/lbm of dry air, of the air-vapor mixture at the outlet
N = number of elements into which the heat exchanger has been subdivided
$\phi_{2,j}$ = vapor-to–dry air mass ratio downstream of the tube row of j^{th} element of the heat exchanger
ϕ_{out} = vapor-to–dry air mass ratio at the outlet

The mixed mean outlet temperature of humid air is related to the mixed mean outlet enthalpy and mixed mean outlet vapor mass fraction. This is shown symbolically by the following relationship:

$$T_{\infty,\text{out}} = f_2(e_{\text{out}}, \phi_{\text{out}}) \tag{C-24}$$

where
e_{out} = enthalpy, Btu/lbm of dry air, of the air-vapor mixture at the outlet
f_2 = functional operator 2
$T_{\infty,\text{out}}$ = mixed mean temperature, °F, of the air-vapor mixture at the outlet
ϕ_{out} = vapor-to–dry air mass ratio at the outlet

C-3.3 Solve the Finite Difference Equations and Evaluate Fouling Resistance

The twenty-four equations shown in para. C-3.2 have to be solved simultaneously to evaluate the tube side fouling resistance. The following variables are known from the test: $T_{t,\text{in}}$; $T_{\infty 1}$; $p_{\infty 1}$; W_t ; $T_{t,\text{out}}$; $T_{\infty,\text{out}}$; and p_{tot}.

The solution of finite difference eqs. (C-1)–(C-3) and (C-5) requires the overall heat transfer coefficient, U, as a function of location within the heat exchanger. The equations are nonlinear because the coefficients themselves depend on the unknown variables. Therefore, these equations require iterative techniques for their simultaneous solution.

The overall procedure is to assume a tube side fouling resistance and dry-air flow rate. The combination of these two values that matches with the two measured outlet temperatures is the proper air flow rate and tube side fouling resistance.

C-4 TRANSIENT TEST METHOD

The steady-state temperature profiles of fluids inside a shell-and-tube heat exchanger during steady state can be represented by a set of ordinary differential equations. These equations can be integrated when specific heat is constant and when the overall heat transfer coefficient is uniform over the entire heat transfer surface. After integration, the relationship between boundary temperatures, flow rates, specific heat, overall heat transfer coefficient, and the heat transfer area are usually presented in a F-P chart or P-N chart with R as a parameter (see para. C-2).

When a heat exchanger undergoes a transient, the temperature profile of shell and tube side fluids can be represented by a set of partial differential equations. For certain simple boundary conditions, these equations may be amenable to direct closed form solution. However, for arbitrarily specified time-dependent boundary conditions of fluid inlet temperatures or flow rates, a numerical integration must be performed.

To integrate the partial differential equations, the initial condition of the temperatures, in addition to the boundary conditions, are needed.

In the example that follows, the applicable set of finite difference equations, the required test data, and data evaluation procedure are presented for a simplified shell-and-tube heat exchanger. A similar process would be followed for a plate heat exchanger.

C-4.1 Establish the Initial Conditions

Before the difference equations obtained in para. C-4.2 can be solved, the initial conditions (the fluid temperature profiles inside the heat exchanger) must be established. This can be done in one of the following two ways depending on whether the hot fluid flow can be stopped or not.

C-4.1.1 Process (Hot) Fluid Flow Can Be Stopped. Stop the flow of the process fluid through the heat exchanger and watch the inlet and outlet temperatures of the cooling fluid. The inlet temperature of the cooling fluid must be constant. When the outlet temperature of the cooling fluid becomes equal to the inlet temperature, the entire heat exchanger is at the cooling fluid inlet temperature and this is the initial condition.

C-4.1.2 Process (Hot) Fluid Flow Cannot Be Stopped. If the process fluid cannot be stopped, then the heat exchanger must operate at a steady-state condition before the transient testing begins. Under these conditions, the initial temperature profiles at the beginning of transient testing can be obtained by solving the difference equations using any reasonable initial conditions for a long enough period so that a steady state is achieved. The temperature distribution thus calculated will provide the initial conditions for the transient test. In this situation, the cooling fluid is usually stopped, the process fluid loop is allowed to heat up, and the cooling fluid is reinitiated. The initial steady-state condition would normally exist just before the cooling fluid is stopped.

Alternatively, the initial conditions can be established by solving the steady-state differential equations.

If the process fluid flow can be stopped, then this method of establishing the initial conditions should be chosen. In this way, the initial conditions can be directly measured from the test and another calculation is not needed.

C-4.2 Collect the Temperature and Flow Rate Data

Record the following four parameters:

(a) cooling fluid inlet temperature time history
(b) process fluid inlet temperature time history
(c) cooling fluid flow rate time history
(d) process fluid flow rate time history

In addition, record one of the following two parameters:

(e) cooling fluid outlet temperature time history
(f) process fluid outlet temperature time history

If both outlet temperature time histories are measured, then the second outlet temperature can be used as a check.

CAUTION: It is desirable to have steady flow rates. However, if it is not possible, then the heat transfer coefficient needs to be calculated at each time step.

C-4.3 Write the Finite Difference Equations

Write the governing equations in the finite difference form. However, if one wishes to obtain a closed form solution, then one would need to write the differential equations. A closed form solution may not be obtainable in many instances. Under these conditions, a numerical solution of the finite difference equations is the only alternative.

Figure C-3 shows a one-tube pass and one-shell pass countercurrent flow heat exchanger. Figure C-4 shows an infinitesimal element of this heat exchanger bounded by two parallel planes normal to the length of the heat exchanger. The following finite difference equations based on the energy conservation equation and the definition of the overall heat transfer coefficient can be written for the shell and tube side flows. The governing equations for other types of arrangements can be written in a similar way using the procedure described here as a guide.

NOTE: The following equations are dimensionally consistent, and any dimensionally consistent set of units may be used.

For the shell side fluid in the j^{th} element the rate of increase of stored energy is as follows:

$$\Delta(mc)_s\left[\frac{T_{s,j}^{\;p+1} - T_{s,j}^{\;p}}{\Delta t}\right]$$

where

$T_{s,j}^{p}$ = temperature of the shell side fluid in the j^{th} element at the p^{th} time step
$T_{s,j}^{p+1}$ = temperature of the shell side fluid in the j^{th} element at the $(p + 1)^{th}$ time step
$\Delta(mc)_s$ = summation of stored mass and specific heat of the components associated with the shell side flow divided by the number of elements into which the heat exchanger has been divided; these elements are the shell, shell side fluid, and half of the tube wall (the other half of the tube wall thermal inertia is part of the tube side fluid)
Δt = time step size

The rate of energy entering from the shell side of the $(j - 1)^{th}$ element is as follows:

$$(WCp)_s(T_{s,j-1}^{\;p})$$

where

$T_{s,j-1}^{p}$ = temperature of the shell side fluid in the $(j - 1)^{th}$ element at the p^{th} time step

Fig. C-3 Schematic Representation of a Countercurrent Shell-and-Tube Heat Exchanger

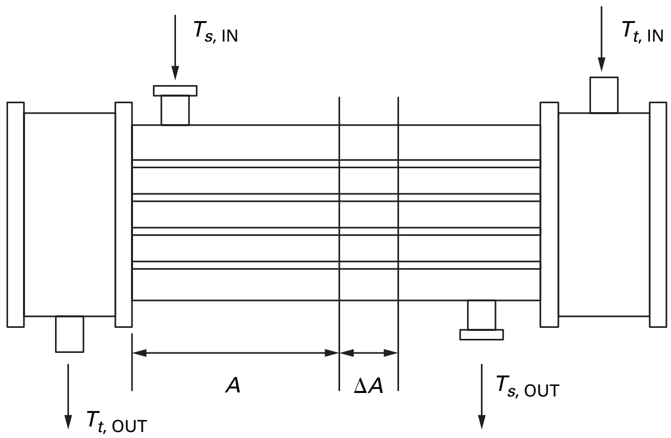
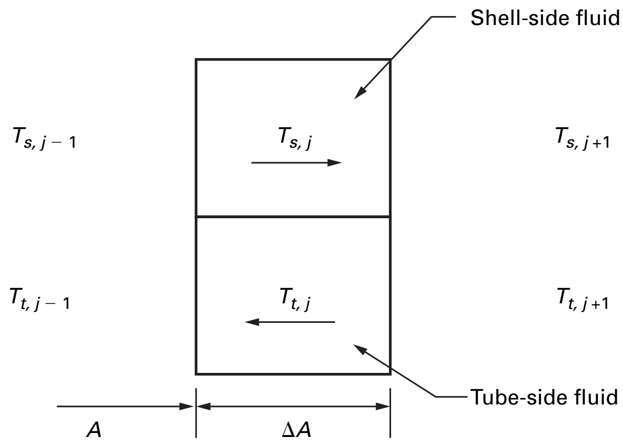


Fig. C-4 A Small Element of a Countercurrent Shell-and-Tube Heat Exchanger



$(WCp)_s$ = product of the shell side mass flow rate and the specific heat

The rate of energy exiting out of the shell side of the j^{th} element is as follows:

$$(WCp)_s(T_{s,j}^{\,p})$$

where

$T_{s,j}^{\,p}$ = temperature of the shell side fluid in the j^{th} element at the p^{th} time step

$(WCp)_s$ = product of the shell side mass flow rate and the specific heat

The rate of energy transfer to the tube side flow in the j^{th} element is as follows:

$$U(\Delta A)(T_{s,j}^{\,p} - T_{t,j}^{\,p})$$

where

$T_{s,j}^{\,p}$ = temperature of the shell side fluid in the j^{th} element at the p^{th} time step

$T_{t,j}^{\,p}$ = temperature of the tube side fluid in the j^{th} element at the p^{th} time step

U = overall heat transfer coefficient, referred to the outside area; this could vary with time if the flow rate is also varying with time

ΔA = total heat transfer area of the heat exchanger divided by the number of elements into which the heat exchanger has been divided

From the law of conservation of energy,

$$(WCp)_s T_{s,j-1}^{\,p} = (WCp)_s T_{s,j}^{\,p} + \Delta(mc)_s\left[\frac{T_{s,j}^{\,p+1} - T_{s,j}^{\,p}}{\Delta t}\right] + U(\Delta A)(T_{s,j}^{\,p} - T_{t,j}^{\,p})$$

where all the variables are defined above.

Solving for the unknown temperature,

$$T_{s,j}^{\,p+1} = \frac{(WCp)_s(\Delta t)}{\Delta(mc)_s}\, T_{s,j-1}^{\,p} + \left[1 - \frac{((WCp)_s + U(\Delta A))\Delta t}{\Delta(mc)_s}\right] T_{s,j}^{\,p}$$

$$+ \frac{U(\Delta A)\Delta t}{\Delta(mc)_s} T_{t,j}{}^p;\ 1 \le j \le N \tag{C-25}$$

where all variables are as defined above.

From the shell side inlet boundary condition,

$$T_{s,0}{}^p = T_{s,\mathrm{in}}{}^p \tag{C-26}$$

where

$T_{s,O}{}^p$ = temperature of the shell side fluid upstream of the first heat exchanger element at the p^{th} time step

$T_{s,\mathrm{in}}{}^p$ = inlet temperature of the shell fluid at the p^{th} time step

For the tube side fluid in the j^{th} element, the rate of increase of stored energy is as follows:

$$\Delta(mc)_t\left[\frac{T_{t,j}{}^{p+1} - T_{t,j}{}^p}{\Delta t}\right]$$

where

$T_{t,j}{}^p$ = temperature of the tube side fluid in the j^{th} element at the p^{th} time step

$T_{t,j}{}^{p+1}$ = temperature of the tube side fluid in the j^{th} element at the $(p + 1)^{\text{th}}$ time step

$\Delta(mc)_t$ = summation of stored mass and specific heat of the components associated with the tube side flow divided by the number of elements into which the heat exchanger has been divided; these elements are the tube side fluid and half of the tube wall (the other half of the tube wall thermal inertia is part of the shell side fluid)

Δt = time step size

The rate of energy entering from the tube side of the $(j + 1)^{\text{th}}$ element is as follows:

$$(WCp)_t T_{t,j+1}{}^p$$

where

$T_{t,j+1}{}^p$ = temperature of the tube side fluid in the $(j + 1)^{\text{th}}$ element at the p^{th} time step

$(WCp)_t$ = product of the tube side mass flow rate and the specific heat

The rate of energy exiting out of the tube side of the j^{th} element is as follows:

$$(WCp)_t T_{t,j}{}^p$$

where

$T_{t,j}{}^p$ = temperature of the tube side fluid in the j^{th} element at the p^{th} time step

$(WCp)_t$ = product of the tube side mass flow rate and the specific heat

The rate of energy transfer from the shell side fluid of the j^{th} element is as follows:

$$U(\Delta A)(T_{s,j}{}^p - T_{t,j}{}^p)$$

where

$T_{s,j}{}^p$ = temperature of the shell side fluid in the j^{th} element at the p^{th} time step

$T_{t,j}{}^p$ = temperature of the tube side fluid in the j^{th} element at the p^{th} time step

U = overall heat transfer coefficient, referred to the outside area (this could vary with time if the flow rate is also varying with time)

ΔA = total heat transfer area of the heat exchanger divided by the number of elements into which the heat exchanger has been divided

From the law of conservation of energy,

$$(WCp)_t T_{t,j+1}{}^p + U(\Delta A)(T_{s,j}{}^p - T_{t,j}{}^p) = (WCp)_t T_{t,j}{}^p + \Delta(mc)_t\left[\frac{T_{t,j}{}^{p+1} - T_{t,j}{}^p}{\Delta t}\right]$$

Solving for the unknown temperature,

$$T_{t,j}{}^{p+1} = \frac{(WCp)_t\,(\Delta t)}{\Delta(mc)_t} T_{t,j+1}{}^p + \left[1 - \frac{((WCp)_t + U(\Delta A))\Delta t}{\Delta(mc)_t}\right]T_{t,j}{}^p + \frac{U(\Delta A)\Delta t}{\Delta(mc)_t} T_{s,j}{}^p;\ 1 \le j \le N \tag{C-27}$$

where the variables are as defined previously.

From the tube side inlet boundary condition,

$$T_{t,N+1}{}^p = T_{t,\mathrm{IN}}{}^p \tag{C-28}$$

where

$T_{t,\mathrm{IN}}{}^p$ = inlet temperature of the tube side fluid at the p^{th} time step

$T_{t,N+1}{}^p$ = temperature of the tube side fluid upstream of the N^{th} element of the heat exchanger at the p^{th} time step

The outlet temperatures are set equal to the temperature in the boundary element, which is just upstream of the outlet. Thus,

$$T_{s,\mathrm{OUT}}{}^{p+1} = T_{s,N}{}^{p+1} \tag{C-29}$$

$$T_{t,\mathrm{OUT}}{}^{p+1} = T_{t,1}{}^{p+1} \tag{C-30}$$

ΔA and Δt must satisfy the inequalities (C-31) and (C-32) simultaneously to satisfy the stability criteria,

$$\Delta t < \frac{\Delta(mc)_s}{(WCp)_s + U(\Delta A)} \tag{C-31}$$

$$\Delta t < \frac{\Delta(mc)_t}{(WCp)_t + U(\Delta A)} \tag{C-32}$$

where the variables are as defined previously.

C-4.4 Solve the Finite Difference Equations and Evaluate the Fouling Resistance

The procedure is to guess a value of total fouling resistance, expressed by eq. (C-34) in terms of inside and outside fouling resistances, and calculate the overall heat transfer coefficient, U, using eq. (C-33). If the flow rates are also changing during the transient testing, then the overall heat transfer coefficient would change with time and would need to be calculated at each time step.

$$\frac{1}{U} = \frac{1}{h_o} + r_{f,t} + r_w + \frac{d_o}{d_i}\frac{1}{h_i} \tag{C-33}$$

$$r_{f,t} = r_{f,o} + \frac{d_o}{d_i} r_{f,i} \tag{C-34}$$

where

d_i = tube inside diameter
d_o = tube outside diameter
h_i = inside heat transfer coefficient referred to the inside area
h_o = outside heat transfer coefficient referred to the outside area
$r_{f,i}$ = inside fouling resistance referred to the inside area
$r_{f,o}$ = outside fouling resistance referred to the outside area
$r_{f,t}$ = total fouling resistance referred to the outside surface area
r_w = tube wall resistance referred to the outside area
U = overall heat transfer coefficient, referred to the outside area; this could vary with time if the flow rate is also varying with time

The procedures for calculating h_i, h_o, r_w, etc. are described in detail in para. C-2.

Equations (C-25) through (C-30) can be solved to yield temperatures with superscript $(p + 1)$ using the values of temperatures with superscript p. At each time step, the temperatures with superscript p are known and the temperatures with superscript $(p + 1)$ are unknown. At the first time step, all the temperatures are known from initial conditions. Thus, the time histories of both outlet temperatures can be calculated in a step-by-step manner. Repeat the calculations with a smaller time step and finer noding to check for convergence of the calculated outlet temperature time histories. The value of fouling resistance that best matches the measured outlet temperature time histories is the actual fouling resistance of the heat exchanger.

C-5 TEMPERATURE EFFECTIVENESS TEST METHOD

The temperature effectiveness test method is used to calculate a projected temperature of a heat exchanger at a known reference point (typically at the design accident conditions) based on data collected at the test point. The method described below can be applied to a wide variety of heat exchangers, and can be calculated by hand. It assumes that the process and cooling fluid mass flow rates at the test point are essentially the same as those at the reference point (within ± 5%). This test method is accomplished by collecting the process and cooling fluid inlet and outlet temperatures at the test point, choosing two temperatures at the reference point, and calculating the remaining two temperatures at the reference point.

C-5.1 Establish Flows

Although the flow rates (cooling fluid and process) are not required to be permanently and accurately measured, since the temperature effectiveness will vary with both flow rates, repeatable flow rates must be established (i.e., same valve lineups, header pressures, pump currents, etc.). Both flows should be within ± 5% of the flow rates that were used to establish the acceptance criteria.

C-5.2 Collect the Temperature Data

Record the following temperature data at steady-state conditions. This set of test data will be termed the test point.

$T_{1,t}$ = process fluid inlet temperature, °F, at test conditions
$t_{1,t}$ = cooling fluid inlet temperature, °F, at test conditions
$T_{2,t}$ = process fluid outlet temperature, °F, at test conditions
$t_{2,t}$ = cooling fluid outlet temperature, °F, at test conditions

C-5.2.1 Data Set

$T_{1,t}$ = 145.0
$t_{1,t}$ = 70.0
$T_{2,t}$ = 123.4
$t_{2,t}$ = 93.0

C-5.3 Calculate the Capacity Rate Ratio

$$R_t = (T_{1,t} - T_{2,t})/(t_{2,t} - t_{1,t})$$

where

R_t = capacity rate ratio (dimensionless) at test conditions

$T_{1,t}$ = process fluid inlet temperature, °F, at test conditions
$t_{1,t}$ = cooling fluid inlet temperature, °F, at test conditions
$T_{2,t}$ = process fluid outlet temperature, °F, at test conditions
$t_{2,t}$ = cooling fluid outlet temperature, °F, at test conditions

C-5.3.1 Data Set

R_t = 0.9391
$T_{1,t}$ = 145.0
$t_{1,t}$ = 70.0
$T_{2,t}$ = 123.4
$t_{2,t}$ = 93.0

C-5.4 Calculate the Temperature Effectiveness

$$P_t = (t_{2,t} - t_{1,t})/(T_{1,t} - t_{1,t})$$

where

P_t = thermal effectiveness (dimensionless) at test conditions
$T_{1,t}$ = process fluid inlet temperature, °F, at test conditions
$t_{1,t}$ = cooling fluid inlet temperature, °F, at test conditions
$t_{2,t}$ = cooling fluid outlet temperature, °F, at test conditions

The temperature effectiveness is also called the thermal effectiveness or temperature efficiency, and is always a number between 0 and 1.

C-5.4.1 Data Set

P_t = 0.3067
$T_{1,t}$ = 145.0
$t_{1,t}$ = 70.0
$t_{2,t}$ = 93.0

C-5.5 Calculate the Projected Temperatures

Using the capacity rate ratio and temperature effectiveness at the test point (as calculated in paras. C-5.3 and C-5.4) and any two temperatures at the reference point (i.e., any two accident condition temperatures), calculate the two projected temperatures at the reference point (i.e., the other two accident condition temperatures) using the following equations. If the accident condition temperature of interest does not meet the acceptance criteria (refer to para. 9), then corrective action is necessary. For the example that follows, the known temperatures and the acceptance criteria (used to compare the calculated temperatures against) are assumed to be the same as para. C-2.1.1.1 data set or as follows:

$T_{1,d}$ = 140.0
$t_{1,d}$ = 75.0
$T_{2,d}$ = 119.3
$t_{2,d}$ = 97.0

C-5.5.1 If $T_{1,d}$ and $t_{1,d}$ Are Known

$$t_{2,d} = t_{1,d} + P_t(T_{1,d} - t_{1,d})$$

$$T_{2,d} = T_{1,d} - R_t(t_{2,d} - t_{1,d})$$

C-5.5.1.1 Data Set

P_t = 0.3067
R_t = 0.9391
$T_{1,d}$ = 140.0
$t_{1,d}$ = 75.0
$T_{2,d}$ = 121.3[3]
$t_{2,d}$ = 94.93[3]

C-5.5.2 If $T_{1,d}$ and $t_{2,d}$ Are Known

$$t_{1,d} = t_{2,d} + P_t(t_{2,d} - T_{1,d})/(1 - P_t)$$

$$T_{2,d} = T_{1,d} - R_t(t_{2,d} - t_{1,d})$$

C-5.5.2.1 Data Set

P_t = 0.3067
R_t = 0.9391
$T_{1,d}$ = 140.0
$t_{1,d}$ = 77.98[3]
$T_{2,d}$ = 97.0
$t_{2,d}$ = 122.1[3]

C-5.5.3 If $T_{2,d}$ and $t_{1,d}$ Are Known

$$t_{2,d} = t_{1,d} + P_t(T_{2,d} - t_{1,d})/(1 - P_tR_t)$$

$$T_{1,d} = T_{2,d} + R_t(t_{2,d} - t_{1,d})$$

C-5.5.3.1 Data Set

P_t = 0.3067
R_t = 0.9391
$T_{1,d}$ = 137.2[3]
$t_{1,d}$ = 75.0
$T_{2,d}$ = 119.3
$t_{2,d}$ = 94.08[3]

C-5.5.4 If $T_{2,d}$ and $t_{2,d}$ Are Known

$$t_{1,d} = t_{2,d} + P_t(t_{2,d} - T_{2,d})/(1 - P_tR_t - P_t)$$

$$T_{1,d} = T_{2,d} + R_t(t_{2,d} - t_{1,d})$$

C-5.5.4.1 Data Set

P_t = 0.3067
R_t = 0.9391
$T_{1,d}$ = 135.1[3]
$t_{1,d}$ = 80.13[3]
$T_{2,d}$ = 119.3
$t_{2,d}$ = 97.0

C-5.5.5 If $T_{1,d}$ and $T_{2,d}$ Are Known

$$t_{1,d} = T_{1,d} + (T_{2,d} - T_{1,d})/R_tP_t$$

$$t_{2,d} = t_{1,d} - (T_{2,d} - T_{1,d})/R_t$$

[3] These values should be compared with the para. C-2.1.1.1 data set, with appropriate consideration of uncertainty.

C-5.5.5.1 Data Set

P_t = 0.3067
R_t = 0.9391
$T_{1,d}$ = 140.0
$t_{1,d}$ = 68.13[3]
$T_{2,d}$ = 119.3
$t_{2,d}$ = 90.17[3]

C-5.5.6 If $t_{1,d}$ and $t_{2,d}$ Are Known

$$T_{1,d} = t_{1,d} + (t_{2,d} - t_{1,d})/P_t$$

$$T_{2,d} = T_{1,d} - R_t(t_{2,d} - t_{1,d})$$

C-5.5.6.1 Data Set

P_t = 0.3067
R_t = 0.9391
$T_{1,d}$ = 146.7[3]
$t_{1,d}$ = 75.0
$T_{2,d}$ = 126.1[3]
$t_{2,d}$ = 97.0

C-6 BATCH TEST METHOD

The batch test method is used to calculate the temperature effectiveness and overall heat transfer coefficient of a heat exchanger by measuring initial and final process temperatures over a measured time period, while holding the cooling fluid inlet temperature constant. Using the thermal capacity of a reservoir (i.e., the process fluid), the temperature effectiveness and overall heat transfer coefficient can be calculated.

The following example demonstrates the batch test method for a reservoir of process fluid containing 100,000,000 lb of water being cooled from 200°F to 180°F in 20.55 hr. The flow rate of the cooling fluid is 1,000,000 lb/hr and the inlet temperature of the cooling fluid is 60°F. The shell side of the heat exchanger is supplied by the fluid of the reservoir.

NOTE: Although this example is for the cooling of a reservoir containing the process fluid, the methodology for the heating of a reservoir containing the cooling fluid would be similar.

C-6.1 Calculate the Thermal Capacity of the Process Fluid

$$C_{p,t} = (M_{p,t})(Cp_{p,t})$$

where

$C_{p,t}$ = thermal capacity of the process fluid, Btu/°F, at test conditions
$Cp_{p,t}$ = specific heat of the process fluid, Btu/lbm-°F, at test conditions, from the reference in para. 3.2(e)
$M_{p,t}$ = mass of the process fluid, lbm, at test conditions

C-6.1.1 Data Set

$C_{p,t}$ = 100,000,000
$Cp_{p,t}$ = 1
$M_{p,t}$ = 100,000,000

NOTE: In the event that the thermal capacity of the process fluid reservoir cannot be ascertained accurately, measuring the heat duty through the heat exchanger as a function of time and integrating it to obtain the total quantity of heat transferred during the period of testing is an acceptable procedure.

C-6.2 Calculate the Temperature Effectiveness

$$P_t = [C_{p,t}/(\tau W_{c,t}Cp_{c,t})] \ln[(T_{1,t,i} - t_{1,t})/(T_{1,t,f} - t_{1,t})]$$

where

$C_{p,t}$ = thermal capacity of the process fluid, Btu/°F, at test conditions
$Cp_{p,t}$ = heat capacity of the cooling fluid, Btu/lbm-°F, at test conditions, from the reference in para. 3.2(e)
P_t = temperature effectiveness (dimensionless) at test conditions
$t_{1,t}$ = cooling fluid inlet temperature, °F, at test conditions
$T_{1,t,f}$ = final process fluid inlet temperature, °F, at end of time τ at test conditions
$T_{1,t,i}$ = initial process fluid inlet temperature, °F, at beginning of time τ at test conditions
$W_{c,t}$ = mass flow rate of the cooling fluid, lbm/hr, at test conditions
τ = time required to cool the process fluid, hr

C-6.2.1 Data Set

$C_{p,t}$ = 100,000,000
$Cp_{c,t}$ = 1
$t_{1,t}$ = 60
$T_{1,t,f}$ = 180
$T_{1,t,i}$ = 200
$W_{c,t}$ = 1,000,000
τ = 20.55

therefore,

P_t = 0.75

C-6.3 Calculate the Capacity Rate Ratio

$$R_t = W_{c,t}Cp_{c,t}/W_{p,t}Cp_{p,t}$$

where

$Cp_{c,t}$ = heat capacity of the cooling fluid, Btu/lbm-°F, at test conditions, from the reference in para. 3.2(e)
$Cp_{p,t}$ = heat capacity of the process fluid, Btu/lbm-°F, at test conditions from the reference in para. 3.2(e)
R_t = capacity rate ratio (dimensionless) at test conditions
$W_{c,t}$ = mass flow rate of the cooling fluid, lbm/hr, at test conditions
$W_{p,t}$ = mass flow rate of the process fluid, lbm/hr, at test conditions

C-6.3.1 Data Set

$Cp_{c,t}$ = 1
$Cp_{p,t}$ = 1
$W_{c,t}$ = 1,000,000
$W_{p,t}$ = 833,000

therefore,
R_t = 1.2

NOTE: Refer to para. C-5.5 to calculate projected temperatures at design accident conditions, or continue with the next steps to calculate the overall heat transfer coefficient.

C-6.4 Calculate *NTU*

For countercurrent flow

$$NTU_t = [1/(R_t - 1)] \ln[(1 - P_t)/(1 - P_t R_t)]$$

where
NTU_t = number of transfer units (dimensionless) at test conditions
P_t = temperature effectiveness (dimensionless) at test conditions
R_t = capacity rate ratio (dimensionless) at test conditions

NOTE: Equations for *NTU* for other than countercurrent flow configurations are given in the reference in para. 3.2(c).

C-6.4.1 Data Set

P_t = 0.75
R_t = 1.2

therefore,
NTU_t = 4.58

C-6.5 Calculate U_t (*NTU* Method)

$$U_t = (NTU_t)(W_{c,t})(Cp_{c,t})/A_{o,t}$$

where
$A_{o,t}$ = effective external surface area, ft^2, at test conditions
$Cp_{c,t}$ = heat capacity of the cooling fluid, Btu/lbm-°F, at test conditions, from the reference in para. 3.2(e)
NTU_t = number of transfer units (dimensionless) at test conditions
U_t = overall heat transfer coefficient, Btu/hr-ft^2-°F, based on outside surface area, at test conditions
$W_{c,t}$ = mass flow rate of the cooling fluid, lbm/hr, at test conditions

C-6.5.1 Data Set

$A_{o,t}$ = 10,000
$Cp_{c,t}$ = 1
NTU_t = 4.58
$W_{c,t}$ = 100,000

therefore,
U_t = 458

NOTE: For NTU curves that are available for split-flow, divided-flow, and cross-flow heat exchangers, $T_{1,t}$ and $T_{2,t}$ must be for the shell side fluid and $t_{1,t}$, $t_{2,t}$, $W_{c,t}$, and $Cp_{c,t}$ *must* be for the tube side fluid.

Refer to para. C-2.2.7 to calculate (with some additional data) the projected overall heat transfer coefficient and heat transfer rate at design accident conditions.

C-7 TEMPERATURE DIFFERENCE MONITORING METHOD

This example examines a typical emergency diesel generator (EDG) heat exchanger that is depended upon to displace 12.37 million Btu/hr at design basis accident conditions. The design basis of the heat exchanger is such that the process outlet temperature does not exceed 112°F while displacing the required heat transfer. In this instance, the limiting cooling water inlet temperature (CWIT) is assumed to be 100°F at a flow rate of 1,650 gpm. The process flow inlet temperature is 170°F at a flow rate of 450 gpm. The heat exchanger for this example is a single pass, countercurrent flow heat exchanger with 90–10 copper nickel tubes.

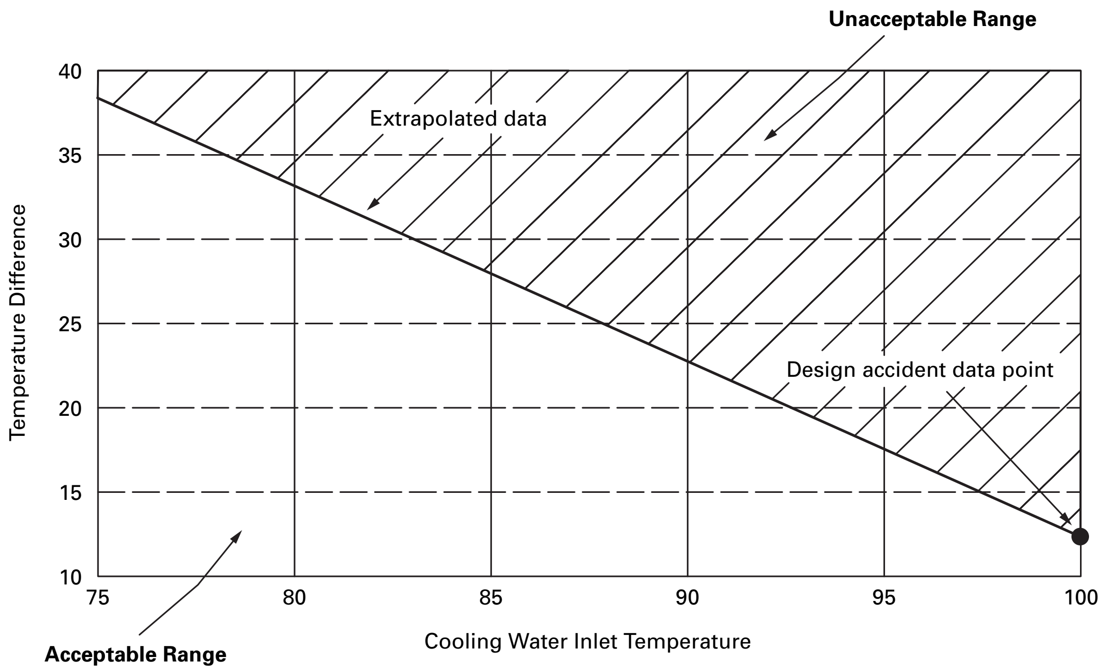
For this example, the temperature of interest is the process fluid outlet temperature, and the terms "tube side" and "cooling water" are used interchangeably.

CAUTION: In reality, the EDG might employ a temperature control valve to modulate process flow to the heat exchanger to prevent too much or too little heat from being removed if it detected a process fluid temperature outside a specified range. If this were to occur, significant changes in the process flow may influence the resulting process fluid outlet temperature, the rate of heat transfer, as well as the cooling water outlet temperature. Significant deviations in the process flows, heat load, and process inlet temperature may invalidate the use of this monitoring method unless their effects are taken into consideration.

Since seasonal influences may significantly affect the cooling water inlet temperature, it may be desirable to establish a correlation that can be used to bound the acceptable operating range of the heat exchanger as the cooling water inlet temperature varies with the season, as shown in Fig. C-5.

Figure C-5 shows that the temperature difference between the process fluid outlet temperature and the cooling water inlet temperature may be increased significantly above the 13.73°F value as the cooling water inlet temperature decreases. Additionally, this figure is based on the heat exchanger supplying the required heat transfer of 12.37 million Btu/hr, with the process fluid inlet temperature at 170°F and with the process flow and the cooling water flow rates at 450 and 1,650 gpm, respectively. For example, at 90°F, the baseline cleanliness test revealed a temperature difference of 3.44°F. By using this correlation, the temperature difference can be allowed to increase to approximately 23°F before the heat exchanger would traverse the point where it would no longer satisfy its performance requirements.

Fig. C-5 Cooling Water Inlet Temperature Versus Temperature Difference



Temperature difference = ΔT
Cooling water inlet temperature = t_1

The heat exchanger tube resistance (and resulting temperature difference) is permitted to increase as the cooling water inlet temperature decreases for the reason that the performance of the heat exchanger meets its design basis heat transfer requirements. In this example, a tube resistance of 0.006624 hr-ft^2-°F/Btu would be permitted provided that the CWIT was equal to or less than 75°F. With a CWIT of 85°F, the limiting tube resistance becomes 0.005205 hr-ft^2-°F/Btu. Furthermore, as the CWIT increases to the design basis temperature of 100°F, the limiting tube resistance is further reduced to 0.002962 hr-ft^2-°F/Btu.

CAUTION: As the cooling water inlet temperature starts an upward trend, the degree of operating margin will be reduced in a corresponding manner and experience will be the best guide to dictate corrective actions in a timely manner. In this example, the operating margin may be the difference between the limiting CWIT as determined by the current temperature difference ($T_2 - t_1$) and the actual CWIT, t_1.

The procedure for this example is given below.

C-7.1 Calculate the Temperature Difference at Design Accident Conditions

$$\Delta T_d = T_{2,d} - t_{1,d}$$

where

$t_{1,\mathrm{d}}$ = cooling fluid inlet temperature, °F, at design accident conditions

$T_{2,d}$ = process fluid outlet temperature, °F, at design accident conditions

ΔT_d = temperature difference, °F, at design accident conditions

C-7.1.1 Data Set

$t_{1,d}$ = 100
$T_{2,d}$ = 112
ΔT_d = 12

C-7.2 Plot the Design Accident Condition Data

Plot the data point corresponding to $t_{1,d}$ and ΔT_d, as shown in Fig. C-5.

C-7.3 Extrapolate the Design Data to Determine the Acceptable Range

Extrapolate the design data to determine the acceptable range of temperature difference (ΔT) when cooler weather causes a drop in the cooling water inlet temperature (CWIT or t_1). This acceptable range (as shown in Fig. C-5) will be used as a tool to gauge future tests.

The extrapolation of the limiting temperature difference corresponding with the lowest anticipated cooling inlet water is derived using a heat balance $Q = m{\cdot}Cp\Delta T = UA(LMTD)$. The cooling water outlet temperature and the shell side outlet temperature are solved using the above heat balance. The shell and tube side flows, as well as the design fouling resistance, are considered constant over the range of the extrapolation.

The heat transfer will increase as the cooling water inlet temperature decreases. The unknowns are the shell side outlet temperature and the tube side outlet temperature.

For Fig. C-5, the tube side flow rate is 1,650 gpm and the shell side flow rate is 450 gpm. The shell side inlet temperature is 170°F and the tube side resistance is 0.002962 hr-ft^2-°F/Btu. At the cooling water inlet temperature corresponding to 100°F, the tube side outlet temperature and the shell side outlet temperature were determined to be 115.19°F and 113.73°F, respectively. At the cooling water inlet temperature corresponding to 75°F, the tube side outlet temperature and the shell side outlet temperature were determined to be 95.29°F and 94.37°F, respectively. Once the shell side outlet temperatures are determined, the value of the temperature difference corresponding to a selected cooling water inlet temperature may be determined and plotted.

C-7.4 Calculate the Temperature Difference at Test Conditions

$$\Delta T_t = T_{2,d} - t_{1,t}$$

where

$t_{1,t}$ = cooling fluid inlet temperature, °F, at test conditions
$T_{2,d}$ = process fluid outlet temperature, °F, at design accident conditions
ΔT_t = temperature difference, °F, at test conditions

C-7.4.1 Data Set

$t_{1,t}$ = 85
$T_{2,d}$ = 112
ΔT_t = 27

This temperature difference at test conditions should be calculated at appropriate intervals to assess the fouling tendency of the heat exchanger and to indicate the potential need for corrective actions. Generally, a lower temperature difference indicates a cleaner heat exchanger.

C-7.5 Plot the Test Data Against the Design Data

Plotting the data point corresponding to the CWIT at test conditions, $t_{1,t}$, and the temperature difference at test conditions, ΔT_t, will reveal that the heat exchanger is closely approaching its limit in transferring the required amount of heat, even in cooler than normal weather. If the CWIT were to increase several degrees, there is a good chance that the heat exchanger would be unable to perform acceptably.

CAUTION: The ability to take advantage of the margin gained during cooler weather may be prevented by the wording in the FSAR or other design documents.

C-8 PRESSURE LOSS MONITORING METHOD

The methodology used in the example given below involves determining the corrected pressure loss for a given heat exchanger. When applying this method, it is important to remember that the type of fouling present in the heat exchanger can significantly affect the sensitivity of this method (see Nonmandatory Appendix B, para. B-11).

C-8.1 Establish Flow and Collect Flow Data

A steady-state flow should be established through the heat exchanger as close to the same flow rate that was used to establish the acceptance criteria as possible. Small differences between the test flow rate and the acceptance criteria flow rate can be corrected in the calculation.

C-8.2 Collect the Pressure Loss Data

Using a differential pressure gauge, record the pressure loss at steady-state conditions, as described in para. C-8.1.

C-8.3 The Corrected Pressure Loss

Since the pressure loss varies with flow rate, it must be corrected from the test flow rate to the acceptance criteria flow rate from which the acceptance criteria was derived.

C-8.3.1 Calculate the Corrected Pressure Loss (PL_c)

$$PL_c = (W_a/W_t)^n(PL_t)$$

where

n = 2.0 if test flow rate is in the turbulent regime
= 1.8 if test flow rate is in the turbulent regime and if the pressure loss is primarily due to frictional losses in flow through the tubes, rather than entrance/exit losses
= 1.0 if test flow rate is in the laminar regime
PL_c = pressure loss (same units as PL_t), corrected to the acceptance criteria flow rate
PL_t = pressure loss (same units as PL_c), averaged from data collected at test conditions
W_a = acceptance criteria flow rate (same units as W_t), on which the acceptance criteria is based
W_t = test flow rate (same units as W_a), as measured at test conditions

CAUTION: Both W_a and W_t must be in the same flow regime.

CAUTION: See Nonmandatory Appendix B for conditions that may cause misleading results.

C-8.4 Calculate the Average Corrected Pressure Loss

Calculate the average PL_c and compare it to the acceptance criteria.

C-9 VISUAL INSPECTION MONITORING METHOD

All inspections should be performed by individuals proficient in corrosion processes, heat transfer, chemistry, materials, operating conditions, etc., and possessing a working knowledge in the general preventative maintenance of heat exchangers. Inspectors must be trained to look for more than just gross fouling and/or blockage and may be required to obtain samples for laboratory analysis. It is good practice to have a fouling/corrosion control program that locates fouling, characterizes and determines the effects on the heat exchangers, and trends the data for predicting performance.

The best time to perform the inspection is immediately following disassembly, since the thickness of many biofilm layers is significantly reduced when they are in a dry condition and can appear as a deceptively thin layer. One method to ensure accurate film thickness measurement is to remove a sample tube section from the bundle and cap the ends of the fluid-filled tube for transporting to the laboratory for evaluation.

It should be noted that visual inspection cannot determine the integrity of the tube material and should not be substituted for the predictive monitoring program where eddy current testing or other nondestructive examination (NDE) methods are used. In most cases, eddy current testing can determine the integrity of the tube material but should not be used to determine fouling conditions. A combination of visual inspection and eddy current testing of the tube IDs is recommended where tube wall degradation is suspected.

C-9.1 Inspection Types

Visual inspections can be performed on shell- and tube-type as well as plate-type heat exchangers. Each type of heat transfer surface requires a different type of inspection. These inspection types are described below.

C-9.1.1 Tube Side Inspections. Upon opening the heat exchanger, the inspector should observe and note the amount and type of fouling and debris/sludge present in the heat exchanger, end bells, and tubes. The inspector should obtain samples for laboratory analysis, if required. Special attention should be given to any tube openings that may be plugged by foreign material. Plugged tubes result in removing heat transfer surface and may reduce heat transfer capability (sometimes, if the conditions are right, plugged tubes can result in increased velocity through the tubes, which offsets the effects due to the reduction in heat transfer surface area). The inspection should also be conducted to assess for structural damage, welds, significant wall thinning due to erosion and/or corrosion, tube plug integrity, tube sheet ligaments, and other discrepancies that might affect heat exchanger performance.

The tubes should be visually inspected to determine their condition from the standpoint of both cleanliness and corrosion. Most detailed visual inspections can be conducted using such inspection devices as borescopes, fiberscopes, or video probes.

The most effective method of removing any fouling deposit should be assessed after determining its nature. If pitting is observed, evaluate the need for other NDE to ascertain tube integrity status and possible corrective action.

C-9.1.2 Shell Side Inspections. The shell side normally carries the process fluid, which is usually a closed system and is treated with chemicals to maintain adequate water quality and minimize fouling. However, where the cooling fluid is routed through the shell side, where there has been in-leakage from the cooling water side, or where poor water treatment has contaminated the normally clean side, there is sufficient potential for shell side fouling. This presents additional challenges for inspecting and cleaning, since the outer tube surfaces interface with other structural components (i.e., support plates, and impingement plates) creating areas that may be inaccessible for direct visual inspection.

Fixed tube sheet bundles cannot be removed from their shells easily; therefore, it is necessary to look into the bundle through shell penetrations using either a video probe or a fiberscope, or by removing a tube or section of tube to determine the extent of fouling.

C-9.1.3 Plate Inspections. The basic design of plate-type heat exchangers allows easy access to both the cooling and process fluid sides when disassembled. Limited inspection, without total disassembly, for fouling, corrosion, and debris can be performed by removing inspection plates after draining the heat exchanger. This allows for visual inspection of the inlet and outlet headers and the entrance area to the plate openings by use of inspection devices.

C-9.2 Monitoring Techniques

In addition to direct visual inspection of heat exchanger components, the indirect monitoring techniques described below may be used to detect performance changes via disassembly, fiberscopes, and robotics.

C-9.2.1 Side Stream Monitor. Use of side stream heat exchanger inspections can be employed if accurate and dependable correlations between the side stream heat exchanger and the represented heat exchanger(s) can be established. Such correlations would need to be established for both operating conditions and fouling tendencies (unless both were known to be identical). If inspection results of the representative or side stream heat exchanger identify the need for corrective action, it should be applied to all the representative heat exchangers.

C-9.2.2 Water Quality Monitor. One of the key ingredients of a program to ensure that heat exchangers will maintain their ability to transfer the appropriate amount of heat is adequate water quality. Inspection results will usually be a direct indication of the effectiveness of the applied water treatment. Close monitoring of water quality can be used to predict changes in heat exchanger performance. Thus, the solution for a fouled heat exchanger may simply be to make adjustments in the water treatment process.

C-9.2.3 Infrared Viewer. If the heat exchanger is not heavily insulated, an infrared viewer can be used to identify hot and cold spots within the heat exchanger shell, which may be caused by blocked tube passes, uneven flow distribution, etc. Such data collected and trended over time can be used to detect changes in heat exchanger thermal performance.

C-10 PARAMETER TRENDING

The following are examples of parameters that may be trended.

C-10.1 Test Parameters

If the acceptance criteria can be quantified, and if enough historical data is available (a minimum of three previous test results), then trending of calculated test parameters can be used to determine a projected degradation rate. This will help to ensure operability between scheduled tests.

The following test parameters may be trended to detect heat exchanger performance degradation over time.

C-10.1.1 Fouling Resistance. The fouling resistance, as calculated by the heat transfer coefficient test method, may be trended as an excellent indicator of heat exchanger degradation due to surface fouling. Scheduling of cleaning to maintain acceptable performance is facilitated by trending this calculated parameter.

C-10.1.2 Overall Heat Transfer Coefficient. The overall heat transfer coefficient, as calculated by the heat transfer coefficient test method, may be trended as an excellent indicator of heat exchanger degradation due to surface fouling. The overall heat transfer coefficient is not as sensitive a trending indicator as fouling resistance, because it includes the effects of numerous thermal resistances that do not change with time, but it provides a better direct indication of heat exchanger capability than any of the indicators given below.

C-10.1.3 Temperature Effectiveness. The temperature effectiveness, as calculated by the temperature effectiveness test method, may be trended to provide an indication of possible degradation of the heat exchanger. Although not as sensitive an indicator as the fouling resistance, temperature effectiveness is a reliable indicator of heat transfer performance of the heat exchanger.

C-10.2 Monitored Parameters

C-10.2.1 Pressure Loss. Pressure loss across a heat exchanger, although not a direct indicator of heat transfer capability, is a reliable indicator of fouling caused by the blockage of the heat exchanger flow passages and a weaker indicator of fouling caused by the buildup of scales and films on the heat transfer surface. Sharp increases in pressure loss, readily detectable from trending against time, indicate the onset of fouling due to blockage and either the immediate or future need for inspection and/or cleaning.

C-10.2.2 Temperature Difference. Temperature difference is influenced by normal heat loads and may not be effective for trending.

C-10.3 Other Parameters

C-10.3.1 Temperature. Trending of the component or area temperatures measured by the functional test method, the heat exchanger fluid exit temperatures, or the temperature difference across the heat exchanger provides a useful indication of heat exchanger performance. If inlet temperatures remain constant, measurement of either outlet temperature is an appropriate trending parameter.

C-10.3.2 Temperature Deviation. The deviation of the measured safety-related temperature, as determined by the temperature difference method, from that predicted by the correlation for the measured cooling fluid inlet temperature, may be trended to identify degradation of the heat exchanger.

C-10.3.3 Flow. Flow through a heat exchanger is a less sensitive indicator (than pressure loss) of flow passage fouling. Trending of flow against time, however, may be useful in diagnosing other time-related changes in heat exchanger performance. Where the manufacturer has stated the functionality of a heat exchanger based on a given amount of flow (as in motor and oil coolers), trending flow may be used to monitor heat exchanger performance relative to the minimum flow required.

If flow is trended, then the throttling valves used to control flow to the heat exchanger (indeed, to all heat exchangers on that same train), each time data is gathered, must be in the same position as they would for the "emergency" condition, with automatically operated valves placed in manual. Whatever flow is measured is the flow to be compared with the acceptance criteria. In other words, a flow balance must be achieved.

C-10.3.4 Limiting Cooling Water Inlet Temperature. For heat exchangers with generally small operating margins, the calculated limiting cooling water inlet temperature (LCWIT) is compared to the actual cooling water inlet temperature (CWIT). The difference between the limiting temperature and the actual temperature represents the operating margin and decreases as fouling increases and/or the actual inlet temperature increases.

C-11 UNCERTAINTY ANALYSIS

A summary of the standard statistical method outlined in the references in paras. 3.2(n) through (p), tailored specifically to heat exchanger performance evaluation, is provided below. It accounts for both measurement errors and result sensitivities. It is assumed that the measurement and test conditions lend to treating this data as a normal distribution.

C-11.1 Measurement Errors

The measurement error consists of instrument bias (fixed), precision (random), and spatial errors. A conventional method for calculating measurement errors is summarized below.

The measurement error for each measurement parameter shall be determined as follows.

(a) Combine the bias error and the precision error for the measurement parameter using the square root sum of the squares method.

(b) Repeat the step (a) for each measurement parameter.

For additional details on measurement errors, instrument accuracies, and related topics, see the references in paras. 3.2(n) through (p).

C-11.1.1 Bias Errors. The bias error for each measurement parameter may be determined as follows:

(a) Determine the bias errors associated with each sensor, signal conditioner, and piece of data acquisition equipment in the measurement parameter string. These errors will typically come from manufacturer's reports and calibration capabilities.

(b) Combine these individual bias errors using the square root sum of the squares method for independent errors and then add any dependent errors. The result will be the bias error for that measurement parameter.

(c) Repeat steps (a) and (b) for each measurement parameter.

Determination of the bias errors should be performed prior to the formal collection of any test or monitoring data. This is because the method selected, and the heat exchanger's operating margin, are likely to have a significant effect on the required accuracy of the instrumentation, which may require upgrading.

NOTE: If the same instruments are used and left installed in back-to-back tests (e.g., in pre- and postcleaning tests), then, since the repeatability of the instruments will be reflected in the data acquired in the sample (thus becoming part of the precision error) and since it is only the difference between tests being measured, the bias errors will cancel out and only the precision error needs to be considered. This will allow for the possibility of measuring changes in heat exchanger performance that are less than the bias error.

C-11.1.2 Precision Errors. The precision error for each measurement parameter may be determined as follows:

(a) Collect test data (a set of measurement parameters) consisting of a minimum of 31 data sets ($N \geq 31$).

CAUTION: If fewer than 31 data sets are collected ($N < 31$), the uncertainty analysis that follows will be invalid. More than 31 data sets should be used if greater precision is desired. Refer to the reference in para. 3.2(n) if other than 31 data sets are taken.

(b) Calculate the average value for the measurement parameter (average of N measurements).

(c) Calculate the standard deviation (also referred to as the precision index) for the measurement parameter using the "nonbiased" or "$N - 1$" method.

(d) Divide the precision index for the measurement parameter by the square root of the total number of data sets (31 or greater) to get the precision index of the average value.

(e) Multiply the precision index for the average value by the Student's t test value of 2 to get the precision error for the measurement parameter at the 95% confidence level.

(f) Repeat steps (a) through (e) for each measurement parameter.

C-11.1.3 Spatial Errors. If more than one sensor location is being used to measure the test parameter (at L locations), then a spatial error analysis must be performed in lieu of the bias and precision error analyses described above. The total spatial uncertainty will take the place of the measurement errors used in determining the resultant sensitivities (see para. C-11.2).

NOTE: If a measured parameter is likely to vary throughout the space that contains the process being measured (as does air flow due to the flow profile created in a duct), then multiple measurements at more than one sensor location (at L locations) must be taken and spatial errors must be taken into account.

The total spatial uncertainty consists of the following three parts:

(a) the true spatial variation

(b) the time-dependent variation

(c) the instrument variation attributable to the precision error of the individual sensors

The total spatial uncertainty is equal to the root of the sum of the squares of the other three terms. With this in mind, there are two cases for total spatial uncertainty that need to be considered.

C-11.1.3.1 The first case, which is the simpler of the two, assumes that the sensor bias corresponds to the instrument bias, that the precision index corresponds to the time variation, and that both are small compared to the spatial variation. If this is the case, then the total spatial uncertainty is approximately equal to the true spatial variation and can be determined as follows:

(a) Determine the average (of N readings) for each sensor location (there will be L averages).

(b) Determine the average (of L locations) using the averages calculated in (a); there will be one average.

(c) Determine the differences between the parameter average (b) and the average instrument readings (a) and square the differences (there will be L squared differences).

(d) Sum the square of the differences, divide the sum by the total number of sensors less one ($L - 1$), and then take the square root.

If the assumptions made for this case are not true, then the above analysis will overestimate the contribution of the spatial variations to the measurement uncertainty.

C-11.1.3.2 The second case to consider is when the instrument precision and/or the time variations are not small compared to the true spatial variation. In this case, the instrument variation and the time variation should be removed from the total spatial uncertainty, as appropriate. For the second case, the instrument variation can be approximated by dividing the given instrument bias by the Student's t distribution for infinite degrees of freedom.

The time variation can be determined as follows:

(a) Determine the pooled variation.

(1) Sum the squares of the difference between the overall average (of $N \times L$ readings) and the individual sensor reading for each sensor ($N \times L$ readings).

(2) Divide the value in (1) by the product of the number of sensors (L) times the number of readings less one ($N - 1$) taken by an individual sensor.

(3) Take the square root of the value determined in (2).

(b) Divide the pooled variation by the square root of the sum of the number of readings for all sensors ($N \times L$ readings).

The true spatial variation may be calculated by the method presented in the first case. The total spatial uncertainty can then be calculated as first presented.

NOTE: Additional guidance on spatial errors is presented in the reference in para. 3.2(n).

C-11.1.4 Temperatures. The smaller the temperature differences, the more accurate the temperature measurements will need to be. The following techniques should be used to minimize temperature measurement errors:

(a) Calibrate temperature sensors and data acquisition equipment as a single unit, *in situ*, to arrive at an actual rather than calculated total bias error. If this is not possible, calculate the total bias error using the guidance provided in the reference in para. 3.2(n).

(b) If using digital data acquisition equipment, select a system with the smallest analog-to-digital conversion error (as this error becomes part of the total bias error).

(c) When measuring individual temperatures (e.g., used in calculating the *LMTD*), use precision *RTD*s and individual calibration curves applied to each *RTD*.

(d) When measuring only temperature differences (e.g., ΔTs), use two temperature sensors connected together so that they measure ΔT as a single measurement or use the same measuring device for each temperature measurement. This will cause most of the error terms to "wash out" when any two temperatures are subtracted to calculate a ΔT.

(e) When measuring only temperature differences (e.g., ΔTs), apply the bias error to the temperature differences using the ΔT methodology for nonindependent bias limits [see the reference in para. 3.2(o)].

(f) Calibrate all temperature sensors used as a group (i.e., in the same oil bath).

(g) Calibrate temperature sensors over a range no greater than that expected to occur during the test, at a minimum of three points to minimize bias interpolation errors.

(h) Perform pre- and post-test calibrations to determine the validity of drift values used in calculating the bias error.

(i) Use two (or more) temperature sensors (for *RTD*s, they must be four wire) to measure the same parameter and divide the bias error for one sensor by the square root of the number of sensors used. The sensors must be independent of each other [see the reference in para. 3.2(p)].

(j) Increase ΔTs by adjusting either of the flow rates prior to the test. However, as the ΔTs (and their accuracies) increase due to reduced flows, the accuracies of the flow measurements will correspondingly decrease. Also, reducing test flow rates to below the design accident flow rates will require extrapolation back to the original design accident conditions. In these cases, a compromise must be made between flow accuracies, temperature accuracies, and calculational complexities (see Nonmandatory Appendix B, paras. B-1 and B-2).

(k) Increase ΔTs by maximizing the heat load supplied to the heat exchanger.

(l) Locate temperature sensors such that they are readily accessible to facilitate proper calibration and maintenance.

(m) Always use thermal grease in thermowells to reduce thermowell temperature gradients and temperature sensor response times.

(n) For inlet temperatures, locate the sensor as close to the inlet of the heat exchanger as possible.

(o) For outlet temperatures, locate the sensor downstream of the heat exchanger in such a way as to allow for thorough mixture of the outlet fluid. Temperature stratification in the outlet fluid is a common occurrence and can be avoided by proper placement of the temperature sensor (see Nonmandatory Appendix B, para. B-3).

C-11.1.5 Water Flows. The following techniques should be used to minimize water flow measurement errors:

(a) Install calibrated stainless steel orifices (or comparable high-accuracy primary flow elements) and flow metering runs to provide the required accuracy and sufficient run of smooth pipe.

(b) Account for any fouling layer on the pipe and/or primary flow element in the flow bias error calculation.

(c) Account for the primary flow element design (i.e., concentric/eccentric orifice plate, nozzle, or Venturi) in the flow bias error calculation.

(d) Install ultrasonic flow meters, magnetic flow meters, or annubars, but only after careful consideration of their specific application.

(e) If the heat transfer coefficient test method is chosen, it is also possible to extrapolate the least accurate flow from the most accurate flow by performing a heat balance on both sides of the heat exchanger.

(f) Increase flow rates prior to the test. However, as the flow rate accuracies increase due to increased flows, the accuracies of the ΔT measurements will correspondingly decrease. In these cases, a compromise must be made between flow and temperature accuracies (see Nonmandatory Appendix B, para. B-1).

(g) Locate water flow primary elements inside any bypass loops that may exist around the heat exchanger. If this is not possible, any bypass valve leakage must be reduced to zero to eliminate any errors that might be caused by bypass valve leakages.

For additional information on water flow measurement, see the reference in para. 3.2(q).

C-11.1.6 Air Flows. Accurate air flow measurements are difficult to obtain due to their sensitivity to duct work configurations and the difficulty of instrument installation. The plant configuration should be examined to determine the ability to obtain accurate air flow measurements. The following techniques should be used to minimize air flow measurement errors:

(a) If the heat transfer coefficient test method is chosen, it is possible to extrapolate the less accurate flow (which may be the air flow) from the more accurate flow by performing a heat balance on both sides of the heat exchanger (refer to paras. 6.2.5 and 6.3.5).

(b) Locate air flow sensors in straight, unobstructed sections of ductwork according to accepted industry standards [i.e., references in paras. 3.2(r) through (u)].

C-11.1.7 Relative Humidity. Relative humidity can be a very sensitive parameter, especially when condensation is occurring. The following techniques should be used to minimize relative humidity measurement errors:

(a) Inlet relative humidity instruments should be located as close to the heat exchanger as possible.

(b) Outlet relative humidity instruments should be located downstream of the heat exchanger in a location that ensures adequate mixing.

C-11.1.8 Water Pressure Loss. The following techniques should be used to minimize water pressure loss measurement error.

(a) Locate pressure taps close to the heat exchanger to minimize pressure drop due to pipe friction losses.

(b) Locate pressure taps so as to avoid fouling (i.e., locate at top versus bottom of pipe).

(c) Blow down or rod out pressure taps prior to taking measurements to remove any corrosion and/or fouling material (full-ported root valves will help facilitate this).

(d) Use instrument snubbers to reduce instrument reading fluctuations.

C-11.2 Result Sensitivities

The result sensitivities can be determined as follows:

(a) Define the functional relationship between the measurement parameters and the test result. The test result must be calculated in one step. All equations used must first be rearranged so that there is either

(1) a single equation expressing the test result on one side and the measurement parameters on the other or

(2) simultaneously calculated equations (e.g., in a spreadsheet) such that the measurement error for a given measurement parameter is propagated through all linked components simultaneously.

(b) Calculate the nominal result using the average value for each measurement parameter.

(c) Calculate the result sensitivities for each measurement parameter and in each direction (both plus and minus). This is done by calculating the test result using the average values for each measurement parameter plus (and minus) the measurement errors for each measurement parameter (one parameter at a time, and one direction at a time). This process is referred to as numerical perturbation.

Examining the result sensitivities for each measurement parameter is one of the best ways to determine which instruments are worth upgrading to a higher accuracy.

C-11.3 Total Uncertainty

The total uncertainty can be determined as follows:

(a) Take the largest absolute value of the result sensitivities for each measurement parameter (resulting from the numerical perturbation in para. C-11.2) and combine them using the square root sum of the squares method. This is the total uncertainty of the test result.

NOTE: The total uncertainty in the test result may be less than the total error of any one of the measurement parameters. This can occur if there are "linked errors" in the calculation or if the same measurement parameter is used more than once in the calculation. In such cases, some of these errors will cancel out, resulting in a lower total uncertainty in the test result.

(b) Apply the total uncertainty to the nominal result in the most conservative direction to arrive at a test result with 95% coverage. This is the value that should be compared to the acceptance criteria (per para. 9).

C-11.4 Calculated Parameters

All test condition calculations shall be performed using the most accurate measured parameters as the required parameters (see para. 6). The other parameters (calculated from the required parameters) shall be chosen as described below.

For example, since $Q_{p,t}$ must equal $Q_{c,t}$, any one of the six parameters (inlet temperature, outlet temperature, and flow rate for both the process and the cooling fluid sides of the heat exchanger) can be calculated from the other five measured parameters. If all six parameters can be measured and one parameter is known to result in a greater total uncertainty than the others, then that parameter should be calculated, rather than measured, to avoid compounding its error through the calculation.

(a) To minimize error propagation through the calculations that follow the calculation of heat duty, the total uncertainty should be calculated for both the measured and the calculated value of each of the six parameters. If any calculated parameter results in less total uncertainty than the corresponding measured parameter, then the calculated parameter that has the least contribution to total uncertainty should be used instead of the corresponding measured parameter. Refer to para. 3.2(n) for additional guidance concerning the weighting method.

(b) To provide a "consistency" check on the test data, this sixth parameter should also be measured. The measured value of the parameter should be compared to the calculated value of the parameter. If the calculated value does not agree with the measured value, refer to Nonmandatory Appendices A and B for potential causes.

PART 24

PART 24
Reactor Coolant and Recirculation Pump Condition Monitoring

1 INTRODUCTION

There is a need for standardization of in situ monitoring of reactor coolant pumpsets and recirculation pumpsets for the detection of pump and driver degradation and for the detection or prediction of equipment faults prior to functional failure. The intent of this Part is to provide a standard method for monitoring these pumpsets with a primary focus on vibration, bearing temperature, and seal condition monitoring. Additional parameters and techniques are used as appropriate. The data obtained are intended for monitoring and diagnostic analysis.

1.1 Scope

This Part establishes the requirements for monitoring of the reactor coolant pumps in pressurized water reactors and recirculation pumps in boiling-water reactors. This Part establishes the monitoring methods, intervals, parameters to be measured and evaluated, and records requirements.

1.2 Approach

This Part provides the steps necessary to implement a monitoring program. The major steps necessary include

(a) identifying the potential pumpset faults that could be detected by monitoring and the symptoms that would be produced by these faults

(b) determining the analysis techniques that are appropriate to the faults that are being monitored

(c) establishing the monitoring program necessary to detect equipment deterioration or pumpset faults early enough to prevent functional failure of the pumpset

(d) applying the evaluation criteria for each pumpset

2 DEFINITIONS

0.3×: 0.3 times the machine running speed.

0.5×: 0.5 times the machine running speed.

1×: the machine running speed in cpm.

1× amplitude: vibration amplitude at running speed. (See also *harmonics*.)

1× vectors: the vector of vibration, amplitude, and phase, at the machine running speed.

2×: twice the machine running speed.

2× amplitude: vibration amplitude at twice running speed. (See also *harmonics*.)

2× vectors: the vector of vibration, amplitude, and phase, at twice the machine running speed.

acceleration: the time rate of change of velocity. The unit for vibration acceleration is G. 1.0 G = acceleration of earth's gravity = 386.4 in./sec^2 = 32.17 ft/sec^2 = 9.81 m/sec^2.

accelerometer: an inertial transducer that converts the acceleration of mechanical vibration into a proportional electric signal.

acceptance region: area around the 1× or 2× vibration vector wherein the amplitude and phase are considered normal.

accuracy: the closeness of agreement between a measured value and the true value.

alarm, level 1: called Alert in API 670.

alarm, level 2: called Danger in API 670.

aliasing: in measurements, false indication of frequency components caused by sampling a dynamic signal at too low of a sampling frequency.

amplitude: the magnitude of vibration. Displacement is measured in peak to peak. Velocity and acceleration are measured in zero to peak or RMS.

asynchronous sampling: sampling of a vibration signal at time intervals not related to shaft rotation.

axial position: the average position, or change in position, of a rotor in the axial direction with respect to some fixed reference.

balance: see *unbalance*.

balance resonance speed: a shaft rotational speed (or speed range) that is equal to a lateral natural frequency of the rotor system. [See also *critical speed(s)*.]

baseline data: reference data set acquired when a machine is in acceptable condition after installation or most recent overhaul that establishes a basis to which subsequent data may be compared.

bearing instability: vibration caused by interaction between the fluid in the bearing and the rotor.

Bod plot: a pair of graphs in Cartesian format displaying any vibration vector (phase lag angle and amplitude) as a function of shaft rotational speed. The y-axis of the top graph represents phase lag angle, while the y-axis of the bottom graph represents amplitude. The common x-axis represents shaft rotational speed. Sometimes called an unbalance response plot.

cascade plot: a series of spectrum plots taken over a speed range, usually at set speed intervals plotted against the speed.

casing vibration: the absolute vibration of machine housing or structure, usually measured on the bearing housing.

channel/loop: consists of a transducer or sensor, signal conditioning, and the hardware required to display its output signal.

critical speed(s): often any shaft rotational speed that is associated with high vibration amplitudes. In general, the speed that corresponds to a rotor lateral mode resonance frequency excited by rotor unbalance, in which case it is more correctly called the balance resonance speed.

diagnostics: methods used to identify sources of malfunctions from data gathered using monitoring and analytical equipment.

displacement: a vibration measurement that quantifies the amplitude in engineering units of mils (1 mil = 0.001 in.) or micrometers.

electrical runout: a source of error on the output signal from a noncontacting probe system resulting from nonuniform electrical conductivity properties of the observed material or from the presence of a local magnetic field at a point on the shaft surface.

filter: electronic circuitry designed to pass or reject a specific frequency band of a signal.

frequency: the repetition rate of a periodic vibration per unit of time. Vibration frequency is typically expressed in units of cycles per second (Hertz), cycles per minute, or orders of shaft rotational speed.

frequency component: the amplitude, frequency, and phase characteristics of a dynamic signal filtered to a single frequency.

G: a unit of acceleration. (See also *acceleration*.)

gap voltage: a DC voltage from a proximity transducer that quantifies the distance from the tip of the transducer to the observed shaft surface.

Hanning window: windows are weighting or resolution functions. A Hanning window provides an amplitude accuracy versus frequency resolution compromise for general purpose measurements for rotating equipment.

harmonics: the vibration content of a spectrum consisting of exact frequency integer multiples or submultiples of a fundamental frequency.

Hertz (Hz): unit of frequency measurement in cycles per second.

loose part: a metallic object that is disengaged and free to drift or constrained and can affect nearby components.

mechanical runout: a source of error in the output signal of a proximity probe system resulting from surface irregularities, out of round shafts, and such.

misalignment: the degree to which the axes of machine components are noncollinear, either in offset or angularity.

mode shape: the deflection shape of a pumpset and support structure due to an applied dynamic force at a natural frequency; also used for the deflection shape of a forced response.

natural frequency: the frequency of free vibration of a mechanical system at which a specific natural mode shape of the system elements assumes its maximum amplitude.

nonsynchronous: any component of a vibration signal that has a frequency not equal to an integer multiple of shaft rotational speed (1×).

N× amplitude: vibration amplitude at *N* times running speed, where *N* is an integer. (See also *harmonics*.)

oil whirl: see *bearing instability*.

orbit: the path of the shaft centerline motion at the probe location during rotation.

overall: a value representing the magnitude of vibration over a frequency range determined by the design of the instrument or as specified. Expressed as rms, zero-peak (0-P), and peak-to-peak (P-P).

phase angle: the timing relationship, in degrees, between two signals, such as a once per revolution reference probe and a vibration signal.

polar plot: a graphical format used to display vectors (amplitude and phase) on a polar coordinate system.

preload: a unidirectional, axial, or radial static load due to external or internal mechanisms. Also applied to the installation configuration of certain bearing types such as tilting pad bearings.

proximity probe: a noncontacting device that measures the displacement motion and position of a surface relative to the probe-mounting location. Typically, proximity probes used for rotating machinery measure shaft displacement motion and position relative to the machine bearing(s) or housing.

pumpset: consists of the motor, coupling, pump, bearings, and seals.

radial vibration: shaft or casing vibration that is measured in a direction perpendicular to the shaft axis, often called lateral vibration.

rub: potentially severe machine malfunction consisting of contact between the rotating and stationary parts of a machine.

shaft bow: a condition of deformation of a shaft that results in a curved shaft centerline.

spectrum averaging: the averaging of multiple spectra to reduce random nonrecurring frequency components.

spectrum plot: an x-y plot in which the x-axis represents vibration frequency and the y-axis represents amplitudes of vibration components.

speed: the frequency at which a shaft is rotating at a given moment, usually expressed in units of revolutions per minute (rpm) or revolutions per second (rps).

steady-state data: data acquired from a machine at constant shaft rotational speed and process conditions.

synchronous: the component of a vibration signal that has a frequency equal to an integer multiple of the shaft rotational speed (1×). (See also *time synchronous averaging.*)

synchronous sampling: sampling of a vibration waveform initiated by a shaft phase-reference transducer.

time synchronous averaging: the averaging of multiple synchronously sampled waveforms to reduce the nonrotational-related frequency components.

transducer: generally, any device that converts a physical phenomenon into an electrical signal proportional to the amplitude of the sensed parameter (e.g., an accelerometer generates an electrical signal proportional to the acceleration of the point at which it is mounted).

trend: any parameter whose magnitude is displayed as a function of time.

unbalance: a rotor condition where the mass centerline (principal axis of inertia) does not coincide with the geometric centerline, expressed in units of gram-inches, gram-centimeters, or ounce-inches.

unfiltered: data that is not filtered and represents the original transducer output signal.

vane passing frequency: a frequency equal to the number of vanes times shaft rotational speed.

vector: a quantity that has both magnitude and angular orientation. For a vibration vector, magnitude is expressed as amplitude (displacement, velocity, or acceleration) and direction as phase angle (degrees).

velocity: the time rate of change of displacement. Units for velocity are inches/second or millimeters/second.

waterfall plot: similar to cascade plot, except that the *z* axis is usually time or another time-related function, such as load, instead of shaft rotational speed (rpm or rps).

waveform plot: a presentation of the waveform of a signal as a function of time. A vibration time waveform can be observed on an oscilloscope in the time domain.

3 REFERENCES

The following is a list of publications referenced in this Part.

API 670, Vibration, Axial Position, and Bearing Temperature Monitoring Systems, 3rd Edition, November 1993

Publisher: American Petroleum Institute (API), 1220 L Street, NW, Washington, DC 20005-4070

ASME OM-S/G-2003, Part 12, Loose Part Monitoring in Light-Water Reactor Power Plants

ASME OM-S/G-2003, Part 14, Vibration Monitoring of Rotating Equipment in Nuclear Power Plants

Publisher: The American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016-5990; Order Department: 22 Law Drive, P.O. Box 2300, Fairfield, NJ 07007-2300

ASTM D 6224-98, In-service Monitoring of Lubrication Oil for Auxiliary Power Plant Equipment

ASTM E 1934-99, Guide for Examining Electrical and Mechanical Equipment with Infrared Thermography

Publisher: ASTM International (ASTM), 100 Barr Harbor Drive, West Conshohocken, PA 19428

NEMA MG 1, Motors and Generators

Publisher: National Electrical Manufacturers Association (NEMA), 1300 North 17th Street, Rosslyn, VA 22209

4 MACHINE FAULTS

4.1 Introduction

Tables 1 through 3 list some of the more common pumpset and seal faults, their typical symptoms, and the more common analysis techniques employed to detect faults. The tables are not intended to be diagnostic tables. Table 1 describes pumpset mechanical faults, Table 2 describes seal faults, and Table 3 describes electrical motor faults.

5 VIBRATION, AXIAL POSITION, AND BEARING TEMPERATURE MONITORING EQUIPMENT

5.1 General

5.1.1 Pumpsets monitored under this standard shall have a permanently installed vibration, axial position, and bearing temperature monitoring system as specified in API 670 with the additions, deletions, and changes as specified below. Although API 670 was written for horizontal machines, the most significant change required for API 670 to apply to the pumpsets defined in this Standard are the location and orientation of the transducers. See paras. 5.3.2 and 5.3.3.

Table 1 Pumpset Mechanical Faults

Possible Faults	Typical Symptoms	Analysis Type
Excessive bearing preload	1× and occasionally 2× vectors, non-circular orbit, bearing temperature rise	Bearing temperature, orbit, oil properties, spectra, trend, and vector
Hydraulic instability	Nonsynchronous, random vibration < 1× speed	Average spectra and trend
Bearing instability	Vibration at 0.3× to < 0.5× speed	Orbit, spectra, and trend
Rub (partial or full rotation)	Harmonics of running speed, truncated waveforms	Orbit, spectra, trend, waveform, and vector
Shaft bent/bowed	Vibration at 1× speed	Orbit, spectra, and vector
Cracked shaft	Changes in 1× and 2× amplitude and phase	Orbit, spectra, trend, and vector
Unbalance	1× vectors and a typically circular orbit	Orbit, trend, and vector
Worn/damaged bearings	1× amplitude or increase in harmonic amplitudes	Bearing temperature, orbit, oil properties, spectra, trend, and vector
Looseness	1× vector increase, harmonics of running speed, truncated waveforms	Spectra, waveform, and trend
Coupling misalignment or damage (angular/parallel)	1× and occasionally 2× vectors, noncircular orbit, bearing temperature rise	Bearing temperature, orbit, spectra, and vectors

Table 2 Seal Faults

Possible Faults [Note (1)]	Typical Symptoms	Analysis Type
Seal Chipped Cracked seal faces Pinched or cut elastomers Wear Dirt accumulation Blocked controlled bleedoff	Excessive leakage Failure to stage Increment in cavity temperature Increase or decrease of bleedoff flow Increase of bleedoff or leakage temperature Unbalanced seal pressure and temperatures Seal pressure oscillations (spikes)	Trend and correlation of seal parameters, such as flow, temperature, and pressure
Support systems Pressure surges Reduced cooling and/or injection water flow Increased CCW temperature		

NOTE:
(1) Some seal faults, such as excessive age and heat checking, cannot be detected by a monitoring system.

5.1.2 Proximity probes are the preferred method of monitoring. Accelerometers may be used in addition to the proximity probes.

5.1.3 Instrumentation shall be suitable for the expected radiation where the instrument is to be installed.

5.2 Monitoring System

5.2.1 Monitors shall be in a controlled, indoor environment, preferably near or in the control room and easily accessible by operations personnel, with an audible alarm in the control room and a visual display of

Table 3 Electrical Motor Faults

Possible Faults	Typical Symptoms [Note (1)]	Analysis Type
Broken rotor bar	Np*S sidebands around 1× vibration, Np*S vibration Np*S sidebands around line frequency current, motor speed decrease	Motor current spectra, vibration spectra, and waveform
Nonuniform air gaps	2× line frequency vibration; Np*S sidebands around 1× vibration; Np*S vibration Np*S sidebands around line frequency current; unusual shaft position change on start; rotor bar, stator slot frequencies, and sidebands	Motor current spectra, shaft centerline position, vibration spectra, and waveform
Insulation breakdown	Electrical protection relays actuate breakers	Visual examination of protective relays

NOTE:
(1) Np = number of poles on motor; S = slip.

the measured parameters. This display need not be dedicated and may be shared with other parameters, as through the process computer, etc. The readout ranges specified below may be changed to meet special requirements. Reference API 670, para. 3.5.2.

5.2.2 The following parameters shall activate an audible alarm in the control room and shall be displayed:

(a) overall vibration amplitude
(b) 1X and 2X vectors, amplitude and phase of vibration
(c) thrust position
(d) bearing temperature
(e) vibration monitor circuit fault as in API 670, para. 3.5.1.1(k)

5.2.3 The number of relays may be different from those specified in API 670, para. 3.4.2.1.

5.2.4 The physical length of the probe and integral cable shall be in accordance with API 670, para. 3.1.1.4, if practicable. Other lengths may be specified if required.

5.2.5 The physical length of the probe extension cable shall be in accordance with API 670, para. 3.1.2, if practicable. Other lengths may be specified if required.

5.2.6 Radial proximity vibration monitors' readout may be analog or digital. If analog, the readout range shall be from 0 mils to at least 20 mils (500 μm) peak-to-peak displacement, with 0.5 mil (15 μm) resolution. If digital, the readout range shall be at least 25 mils (600 μm) with at least 0.5 mil (15 μm) resolution. Reference API 670, para. 3.5.3.1. Other ranges can be used as necessary for machine-specific needs.

5.2.7 Axial position monitors' readout may be analog or digital. The readout range shall be from −40 mils to +40 mils (−1.0 mm to 1.0 mm) axial movement, with at least 2 mil (50 μm) resolution. For sensor locations other than as specified in para. 5.4.1, the range may need to be evaluated. Reference API 670, para. 3.5.5.1. Other ranges may be used.

5.2.8 Accelerometer monitors shall contain an integrator to convert the sensed acceleration to velocity. Monitors may be analog or digital. If analog, the readout range shall be from 0 in./sec to 1.0 in./sec (25 mm/sec) peak. Reference API 670, paras. 3.5.4.1 and 3.5.4.2. Other ranges may be used.

5.2.9 Accelerometer monitors shall contain a high pass filter in accordance with API 670, para. 3.5.4.4. The filter shall be set to one-third of the minimum running speed.

5.2.10 Accelerometer monitors shall contain a low pass filter in accordance with API 670, para. 3.5.4.4. This filter shall be set to the higher of 1.5 times rotorbar pass frequency or 1.5 times stator slot passing frequency.

5.3 Radial Proximity Sensor Locations

5.3.1 Each journal bearing in the pumpset including the motor, thrust bearing assembly (if present), and the pump shall have two proximity probes (*X* and *Y*) installed in accordance with para. 5.3.3 or API 670, para. 4.1.1.

5.3.2 Each pair of *X* and *Y* probes shall be coplanar. All *X* probes shall have the same angular orientation. The *Y* probes shall be 90 deg ± 5 deg from the *X* probes in a counterclockwise direction as seen from the top of the motor looking down. If practicable, the *X* plane shall be in line with the discharge pipe. Reference API 670, para. 4.1.1.1.

5.3.3 The probes monitoring the pump shaft shall be located above the seal housing as close as practicable to the top of the seal. Reference API 670, para. 4.1.1.1.

5.3.4 Total error due to surface condition, both electrical and mechanical, at the measurement planes in the motor and thrust bearing assembly (if present), shall not exceed 0.5 mils (15 μm). Total error due to surface condition, both electrical and mechanical, at the pump measurement plane specified in para. 5.3.3 may have runout exceeding 0.5 mils (15 μm), but should not exceed

3.0 mils (75 μm). Any error due to surface condition greater than 0.5 mils (15 μm) shall be documented as an 8-point reading including the phase relative to the phase reference mark. Reference API 670, para. 4.1.1.2. This surface condition should not be confused with operational runout.

5.4 Axial Proximity Sensor Locations

Each thrust bearing (motor and pump if present) shall have at least one (two are preferred) axially oriented proximity probes in accordance with API 670, para. 4.1.2. For locations other than specified in API 670, para. 4.1.2, the ranges must be evaluated.

5.5 Phase-Reference Sensor Location

5.5.1 There shall be at least one phase-reference transducer observing the motor rotor for each pumpset in accordance with API 670, para. 4.1.3. This transducer shall be separate from any speed transducer(s) that observe a multitooth gear or are part of a shutdown system or a safety-related system. Reference API 670, para. 4.1.3.

5.5.2 In addition to API 670, para. 4.1.3.6, the marking groove shall provide a pulse width of at least 1% of the shaft rotation period. Reference API 670, para. 4.1.3.6.

5.6 Bearing Temperature Sensors

5.6.1 Bearing temperature sensors are not required on the pump journal bearing. Reference API 670, para. 4.1.5.1.

5.6.2 Radial bearing temperature sensor locations shall consider significant bearing loading. Reference API 670, paras. 4.1.5.1.1 through 4.1.5.1.9.

5.6.3 Both the active and inactive thrust bearings shall have bearing temperature sensors installed. Reference API 670, paras. 4.1.5.2.1 and 4.1.5.2.3.

5.7 Sensor Locations for Optional Accelerometers

5.7.1 The natural frequencies of the combined pumpset and support structures shall be determined by analysis or test or both. Note that this is not a rotor-critical speed analysis. The frequencies and mode shapes calculated or measured shall be used to determine the appropriate locations for the accelerometers, which shall be installed in accordance with API 670, para. 4.2.3.

5.7.2 Three accelerometers shall be mounted to the top of the motor. Two of the accelerometers shall be mounted in the same angular orientation as the *X* and *Y* proximity probes ± 5 deg, and the third shall be caused by sampling a dynamic signal at too low a sampling frequency.

5.7.3 If the running speed of the pumpset is above the first natural frequency or the mode shape is not a simple beam mode, then two accelerometers shall be mounted at each radial bearing except the pump journal bearing.

5.8 Other Specifications

5.8.1 Wiring and conduit are not required to be in conformance to NFPA 70 as specified in API 670, para. 3.6.1. Field-mounted equipment shall be installed in containment subject to containment spray events but not to weather. Drains in conduit low points are not required as specified in API 670, para. 3.6.2.1.

5.8.2 Field-installed instrumentation is not expected to be installed in hazardous locations; thus, the portions of API 670 that refer to requirements for hazardous locations do not apply (API 670, para. 3.8.1).

5.8.3 The system is not expected to be wired into an automatic shutdown system; thus, the provisions of API 670 that refer to automatic shutdown do not apply (API 670, paras. 3.5.1.4, 3.5.1.5, and 3.8.3).

5.8.4 Accelerometers shall be calibrated in accordance with API 670, Table 2B. The lowest calibration frequency shall be the lower of 10 Hz or one-third the running speed.

6 VIBRATION DATA ANALYSIS SYSTEM REQUIREMENTS

6.1 Introduction

The purpose of this paragraph is to present the requirements for a digital analysis system that shall be used to perform the pumpset vibration data analysis and display. The listed data acquisition capability, required to perform the necessary analysis, requires a computer-based digital analysis system. Some of the support functions (signal conditioning, filtering, etc.) can be done with analog equipment. However, digital equipment is required to perform the data sampling, storage, archiving, and analysis.

6.2 Data Acquisition for Dynamic Signals

6.2.1 Introduction. Data acquisition refers to the process of digitally sampling an analog dynamic signal. The system needs to be able to support data acquisition for each of the data collection modes described in para. 8. The following data acquisition specifications provide suitable data for the analysis functions listed in para. 6.4.

6.2.2 General Requirements

(*a*) over-range detection/indication

(*b*) A/D conversion as required to meet the accuracy requirements of para. 6.3

(*c*) dynamic range 78 dB or better

(*d*) magnitude accuracy 5% of full-scale range

6.2.3 Spectra Sampling Requirements

(*a*) 400 line minimum resolution

(b) frequency range

(1) proximity probe at least 20 times full speed of pump

(2) accelerometers at least 10 kHz

(c) Hanning window

(d) anti-aliasing filters

(e) four averages (minimum)

(f) 50% overlap

(g) sample rate 2.56 times frequency range

(h) asynchronous sampling

6.2.4 Waveform Sampling Requirements

(a) at least 100 sample points per revolution at full speed

(b) at least a 10 revolution sample length

(c) no anti-aliasing filters

(d) X and Y probes simultaneously sampled with phase reference

(e) time synchronous averaged waveforms with at least 16 averages

6.3 System Accuracy and Calibration

6.3.1 The channel or loop accuracy including the computer system shall be within 10% for radial shaft vibration, thrust position, and bearing temperature.

6.3.2 The channel or loop accuracy including the computer system for casing vibration shall be within 10% over a range from 0.1 G to 75 G at a single reference frequency. The channel accuracy shall be within 20% over the frequency range, as specified in paras. 5.2.9 and 5.2.10.

6.3.3 The channel or loop accuracy may be calculated using the square-root-of-the-sum-of-squares (SRSS) combination of the individual accuracies of the sensor, the monitor, and the computer system.

6.4 Data Analysis and Display

The following analysis and display functions shall be provided:

6.4.1 General Requirements

(a) cursor readout ability for all plots

(b) manual and auto scaling for all plots

6.4.2 Amplitude and Phase Requirements

(a) Overall amplitudes shall be measured and expressed as acceleration, velocity, or displacement.

(b) In addition to the alarms specified in the API 670 monitoring system, the analysis system shall provide 1× and 2× acceptance region alarms for radial proximity probe channels.

6.4.3 Frequency Domain Analysis

(a) frequency spectra, in which linear amplitudes, accelerations, velocities, or displacements are plotted versus linear frequency expressed as cycles per second, (Hz), cycles per minute (cpm), or orders, synchronized to a phase reference

(b) waterfall plots with at least 50 spectra plotted versus time

(c) cascade plots with at least 50 spectra plotted versus speed

6.4.4 Time Waveform Analysis

(a) time waveform plots of unfiltered data

(b) time waveform plots of time synchronous averaged data

(c) orbit plots of unfiltered data

(d) orbit plots of synchronous (1×) or running speed data

(e) time synchronous averaged orbit plots

6.4.5 Balance/Critical Speed Analysis

(a) Bodé plot for speed-transient data

(b) polar plots for speed-transient data

(c) vector plots for monitoring balance response changes

(d) shaft centerline plots; polar plot of shaft centerline position within bearing

(e) gap voltage plots

6.4.6 Trend Analysis. Trend analysis refers to any measured parameter as a function of time in a Cartesian plot.

6.5 Data Storage

6.5.1 The system shall provide storage and display of either averaged or max./min. data stored at least once per hour or at an interval specified when purchasing the system. Data shall be stored for at least 24 months. The minimum vibration-related data to be stored shall be the overall amplitude, running speed amplitude and phase, twice-running speed amplitude and phase, gap voltage, and speed. The minimum nonvibration-related data to be stored shall be the bearing temperatures, seal parameters per para. 7, pumpset discharge temperature, pumpset pressure, pumpset flow rate, reactor power level, and other parameters as applicable. Averaged data shall be computed as the average of at least ten points collected over the interval. Maximum/minimum data shall similarly apply to at least ten data points.

6.5.2 The system shall provide storage of the following data at a minimal interval of at least once per day:

(a) time waveforms with phase reference

(b) time synchronous waveforms

(c) averaged spectra (eight averages)

6.5.3 The system shall collect and store the data as specified in paras. 6.5.1 and 6.5.2 on an alarm.

6.5.4 The system shall collect and store the vibration-related data as specified in paras. 6.5.1 and 6.5.2 on coastdown and startup at a rate of at least every 50 rpm. Additionally, one set of data, as specified in para. 6.5.2, shall be obtained once the pumpset has reached operating speed.

6.5.5 The system shall provide the capability to change the interval for the data collected in paras. 6.5.1 and 6.5.2 for startup or troubled machine monitoring. The minimum recommended intervals available shall be at least every 2 min for data in para. 6.5.1 and every 1 hr for data in para. 6.5.2.

6.6 Continuous Display of Dynamic Signals

6.6.1 The system shall be capable of displaying any of the plots specified in para. 6.4 except Cascade and Bod with an automatic refresh rate of at least once per 10 sec.

6.6.2 The system shall be capable of printing the display on demand or saving the display data to disk.

7 SEAL MONITORING

7.1 Introduction

7.1.1 Seals monitored under this Standard shall have permanently installed sensors that monitor the parameters as specified below.

7.1.2 Instrumentation shall be suitable for the expected radiation where the instrument is to be installed.

7.1.3 Vibration limits and shaft displacement limits for the pumpset are generally less than that for the seal. Axial displacement for the seal is limited by the spring gap, usually much greater than the 0.060 in. to 0.120 in. (1.5 mm to 3 mm) total axial displacement of the pump shaft. Seal problems will not show up as a vibration indication.

7.2 Monitoring System

7.2.1 Monitors shall be in a controlled, indoor environment, preferably near or in the control room and easily accessible by operations personnel, with an audible alarm in the control room and a visible display of the measured parameters. This display need not be dedicated and may be shared with other parameters, as through the process computer, etc. The readout ranges specified below may be changed to meet special requirements.

7.2.2 The applicable parameters in para. 7.2.4 or 7.2.5 shall activate the audible alarm in the control room and shall be displayed.

7.2.3 The channel or loop accuracy, including the computer system, shall be within 5% for temperature, pressure, and flow.

7.2.4 Hydrostatic Seals. The following parameters when possible shall be recorded at least once per hour:

(a) injection flow
(b) injection temperature
(c) injection pressure
(d) cooling water flow
(e) cooling water temperature
(f) cooling water pressure
(g) bearing water temperature
(h) number 3 seal injection flow to seal
(i) number 3 seal injection temperature
(j) number 3 seal injection pressure

7.2.5 Staged Seals. The following seal parameters when possible shall be recorded at least once per hour:

(a) seal staging pressures
(b) controlled bleedoff flow rate
(c) measured seal leakage rate
(d) controlled bleedoff temperature
(e) lower seal temperature
(f) seal injection temperature
(g) seal injection flow rate
(h) CCW temperature

7.2.6 Also, the following system parameters shall be recorded at the time seal data is collected:

(a) power level
(b) system temperature
(c) system pressure
(d) pump flow
(e) pump speed
(f) pump ΔP

7.2.7 Computer systems shall store data for at least 24 months.

7.3 Monitoring and Analysis Requirements

7.3.1 Introduction. The effective use of the installed monitoring system is crucial to an effective monitoring program. Alarms must be set properly, periodic review of the data must be done, and an effective plan for responding to an alarm must be in place.

7.3.2 Startup Monitoring. Review of the trend of the seal parameters shall be performed at least once per hour during system pressurization.

7.3.3 Periodic Monitoring

(a) The intent of periodic monitoring is as follows:

(1) Provide a separate monitoring system and method to ensure that problems with the seal are not missed because of deficiencies in the installed monitoring system.

(2) Provide long-term trend data offline from the monitoring system.

(3) Ensure that a qualified person periodically reviews the seal condition.

(b) Periodic monitoring is required at least every two weeks. If any seal parameters are unusual, over the alarm value, or a significant trend is seen, perform an

evaluation in accordance with para. 7.4, and perform monitoring in accordance with para. 7.5 as required.

(c) A long-term trending database shall be maintained separate from the installed monitoring system. This archive shall be easily available as required to monitor for long-term changes in seal condition, provide an archive of past seal problems, and provide for statistical and other specialized analysis.

(d) At an interval to ensure no data loss and the usefulness of the long-term trending database, transfer the historical files from the monitoring system to the long-term trending and archiving database.

7.3.4 Shutdown Monitoring. Engineering shall review the trend of the seal parameters at least once per hour during system depressurization.

7.4 Seal Alarm Response

7.4.1 When the installed monitoring system alarms, the first response is usually by the Operators. The initial actions to be taken shall include the following:

(a) false alarm discrimination, i.e., does the alarm clear and was the event related to a plant event such as a pumpset start

(b) severity evaluation

(c) determination if pumpset shall be shut down immediately

(d) notification of engineering for further evaluation

7.4.2 When notified of an alarm, engineering shall make a further evaluation of the condition of the pumpset. This evaluation shall include the following:

(a) correlation of seal data to other plant data

(b) comparison of seal data to other seals and historical data

(c) false alarm discrimination

(d) review of relevant data collected by the monitoring system

(e) evaluation of the seal condition per manufacturer guidelines

(f) determination to implement an enhanced monitoring program in accordance with para. 7.5

7.5 Enhanced Monitoring of a Troubled Seal

If an unusual seal condition is detected, an enhanced monitoring program shall be implemented until the problem is corrected or the pumpset is shut down. The interval of the monitoring shall be based on the trend and the result of the analysis and interpretation.

8 VIBRATION, AXIAL POSITION, AND BEARING TEMPERATURE MONITORING

8.1 Introduction

The effective use of the installed monitoring system is crucial to an effective monitoring program. Alarms must be set properly, periodic review of the data must be performed, and an effective plan for responding to an alarm must be in place.

Table 4 Minimum Monitoring and Recording Intervals

Run Time	Monitoring Interval
Initial 2 min	Continuous
Initial 20 min	2 min
< 24 hr	One reading within the first 24 hr
24–72 hr	24 hr
3–7 days	48 hr
7–15 days [Note (1)]	1 week

NOTE:
(1) Monitoring shall be continued until at least a week after the plant is stable.

8.2 Postmaintenance Monitoring

After every pumpset maintenance, the monitoring specified below shall be performed to verify the condition of the pumpset and to establish new baseline data.

8.2.1 Start-up Monitoring Schedule. Perform monitoring per the schedule provided in Table 4.

8.2.2 Pumpset Start-up Monitoring Procedure.

(a) The loose parts monitoring system, if available, shall be monitored via the speaker or headphones. Select the appropriate sensor to detect a loose part coming from the pump.

(b) Evaluate any loose parts alarms during the run for possible pump-related loose part events.

(c) Monitor the spectra and the orbit.

(d) Monitor the overall vibration using the installed vibration displays.

(e) Take one set of periodic monitoring data per para. 8.3.

(f) If available, set up to record the first 20 min on either tape or a transient data acquisition system. If any unusual vibrations were seen during the run, the data shall be analyzed for the cause of the vibration.

(g) Inspect the orbit and spectra of the *X* and *Y* probes for significant changes.

(h) Monitor the 1× amplitude and phase.

(i) Examine the 1× and 2× vector trends and polar plots of all probes for any unusual changes. For example, the following may indicate an unusual change:

(1) an amplitude increasing at a rate of 1 mil (25 μm) in 5 min

(2) an amplitude increase or decrease of 1 mil (25 μm)

(3) an increase in 2× amplitude of 50% when above 0.5 mils (15 μm)

(4) an increase in 2× amplitude of 1 mil (25 μm)

(5) a change in the phase of the 1× or 2× of 30 deg

(j) If vibration, thrust position, or bearing temperature are unusual, over the alarm value, or a significant

trend is seen, perform an evaluation in accordance with para. 8.6 and perform monitoring in accordance with para. 8.7 as required.

(k) Whenever any spectrum or orbit shows a significant change, make a long-term storage media copy of the filtered and unfiltered orbit, time synchronous average orbit, and the spectra.

(l) Make long-term storage media copies of the data listed below from the installed computer system. Data shall cover the period from before startup to establishment of baseline. Long-term storage media may be paper copies, disk files (floppy, hard drive, optical, etc.), or other retrievable records.

(1) overall vibration amplitude trend plots
(2) thrust position trend plots
(3) bearing temperature trend plot
(4) 1× amplitude and phase trend plots
(5) 1× acceptance region plots
(6) 2× amplitude and phase trend plots
(7) 2× acceptance region plots
(8) waterfall plots as a function of delta time
(9) gap voltage trend plots

(m) After at least 7 days of stable operation, take baseline data per para. 8.3.

8.3 Baseline

8.3.1 A new baseline shall be established for the pumpset after every outage where maintenance work is performed on the pumpsets.

8.3.2 At least 7 days (preferably 15 days) of vibration data at stable operation shall be available before acquiring new baseline data.

8.3.3 The condition of the pumpsets shall be evaluated to be acceptable before accepting the baseline data.

8.3.4 The following baseline data shall be stored for each pumpset:

(a) unfiltered orbit and waveform
(b) spectra
(c) filtered orbit and waveform
(d) time synchronous orbits and waveform
(e) acceptance region plot of the 1× rpm (rps) and 2× rpm (rps) component for each sensor
(f) process data at time of acquiring new baseline data
(g) analog monitor front panel readings
(h) current value displays from computer system of overall amplitude and gap voltage as applicable for each sensor
(i) current alarm settings

8.3.5 The baseline data shall be maintained for the life of the pumpset.

8.4 Periodic Monitoring

8.4.1 The intent of periodic monitoring is as follows:

(a) Provide a separate monitoring system and method to ensure that problems with the pumpset are not missed because of deficiencies in the installed monitoring system.

(b) Provide long-term trend data offline from the monitoring system.

(c) Ensure that a qualified person periodically reviews the pumpset condition.

8.4.2 Periodic monitoring is required at least every 2 weeks. If vibration, thrust position, or bearing temperature are unusual, over the alarm value, or a significant trend is seen, perform an evaluation in accordance with para. 8.6 and perform monitoring in accordance with para. 8.7 as required. As a minimum, the following data shall be reviewed:

(a) current alarms.
(b) alarms received since last review.
(c) trend of gap voltage; note any changes over 2 V.
(d) trend of the overall amplitude for each vibration sensor.
(e) trend of the 1× and 2× amplitude and phase for each vibration sensor.
(f) trend of the bearing temperatures.

8.4.3 A monthly 10-min analog or digital tape recording of each vibration channel is recommended.

8.4.4 A long-term trending database shall be maintained separately from the installed monitoring system. This archive shall be easily available as required to monitor for long-term changes in pumpset condition, to provide an archive of past pumpset problems, and to provide for statistical and other specialized analysis.

8.4.5 At an interval to ensure no data loss and the usefulness of the long-term trending database, transfer the historical files from the monitoring system to the long-term trending and archiving database.

8.4.6 Record the following process data within 1 hr (at steady-state conditions if possible) of the collection of the pumpset condition data:

(a) date/time of monitoring
(b) number of pumpset alarms in period
(c) number of system events in period
(d) power level
(e) system temperature
(f) system pressure
(g) days online
(h) pumpset flow if flow may vary
(i) pumpset speed if speed may vary

8.4.7 If the station has a computerized vibration monitoring program using portable data collectors, data from each channel shall be taken with that system for long-term trending and offline analysis.

8.4.8 Obtain a long-term storage media copy of the alarm list since the last time this procedure was performed.

8.5 Preoutage Coastdown

8.5.1 Before each outage during the normal pumpset coastdown, record the data as specified in para. 6.5.4.

8.5.2 Examine data for any unusual patterns.

8.5.3 Determine coastdown time and compare to normal.

8.5.4 Note orbit shape during coastdown for any unusual patterns.

8.6 Vibration Alarm Response

8.6.1 When the installed monitoring system alarms, the first response is usually by the Operators. The initial actions to be taken shall include the following:

(a) false alarm discrimination, i.e., does the alarm clear, is the circuit fault indication on, and was the event related to a plant event such as a pumpset start

(b) severity evaluation

(c) determination if pumpset shall be shut down immediately

(d) notification of engineering for further evaluation

8.6.2 When notified of an alarm, engineering shall make a further evaluation of the condition of the pumpset. This evaluation shall include the following:

(a) correlation of pumpset data to other plant data.

(b) false alarm discrimination.

(c) review of relevant data collected by the monitoring system.

(d) check of the loose parts system for any corresponding events.

(e) evaluation of the pumpset condition in accordance with para. 10; Part 14 may be used as a guide in this evaluation.

(f) determination if an enhanced monitoring program in accordance with para. 8.7 should be implemented.

(g) determination if alarm values should be changed per para. 9.

8.7 Enhanced Monitoring of a Troubled Pumpset

If unusual vibration or a trend in vibration, thrust position, or bearing temperature is detected, an enhanced monitoring program shall be implemented until the problem is corrected or the pumpset is shut down. The enhanced monitoring program shall include, as applicable, additional instrumentation (tape recorders, oscilloscopes, spectrum analyzers, etc.) and continuous or intermittent attendance by qualified analysis personnel. The interval of the monitoring and data storage shall be based on the severity, rate of change, and the result of the analysis and diagnostics as specified in para. 10. Part 14 may be used as a guide in developing an enhanced monitoring program.

9 ALARM SETTINGS

9.1 Determining Alarm Points for Overall Vibration Amplitude

9.1.1 The alarm values for vibration amplitude shall be based on the baseline values as recorded in para. 8.3.

9.1.2 The Level 1 alarm points for the shaft vibration shall be 1.5 times the baseline value but not exceeding the manufacturer's recommended alarm value.

9.1.3 The Level 2 alarm point for the shaft vibration shall be 2.0 times the baseline value but not exceeding the manufacturer's recommended shutdown value.

9.1.4 The Level 1 alarm point for the casing velocity shall be calculated as 1.5 times the baseline value but not less than 0.1 IPS (2.5 mm/sec). The alarm shall not exceed the manufacturer's recommended alert value or 0.3 IPS (7.5 mm/sec) without review and justification.

9.1.5 The Level 2 alarm point for the casing velocity shall be calculated as 2.0 times the baseline value but not less than 0.2 in./sec (5 mm/sec). The alarm shall not exceed the manufacturer's recommended shutdown value or 0.6 in./sec (15 mm/sec) without review and justification.

9.1.6 The alarm points may be rounded down to the nearest meter division for ease in setting.

9.2 Determining 1× and 2× Vector Acceptance Regions

9.2.1 The alarm values for vector acceptance regions shall be based on recent data collected before the baseline point as recorded in para. 8.3. At least 20 days of data is preferred. Because the vector data tends to be noisier than the overall amplitude data, a sample of data over several days is required.

9.2.2 The phase angle range of the sample of data or the calculated acceptance region may cross the 360–0 deg line. Provisions for correctly calculating and specifying the acceptance region in this case must be implemented in the plant procedures.

9.2.3 The maximum and minimum values from the sample data shall be used for the calculations below.

9.2.4 Acceptance regions shall be developed from the maximum and minimum values. **(07)**

$$\text{Accept} = \left(\frac{\text{max.} + \text{min.}}{2}\right) \pm 1.5(\text{max.} - \text{min.})$$

Table 5 Typical Thrust Position Alarm Setpoints for a Pump With Normal Upthrust

Alarm Level	Thrust Position
Level 2 alarm, up	Zero + 15 mils (375 μm)
Level 1 alarm, up	Zero + 10 mils (250 μm)
Zero	Thrust runner against the upper thrust pads
Level 1 alarm, down	Zero − the thrust clearance − 10 mils (250 μm)
Level 2 alarm, down	Zero − the thrust clearance − 15 mils (375 μm)

9.2.5 Round the angle to a multiple of 15 deg. Round down for minimum and up for maximum. If the phase is undefined for any of the sample data, set the angles to 0 deg and 360 deg.

9.2.6 If less than 10 days of data were used, the phase acceptance range may be increased by subtracting 15 from the minimum phase and adding 15 to the maximum phase.

9.2.7 Round the amplitude acceptance limits down and up to the nearest 0.1 mil (2.5 μm).

9.3 Determining Alarm Points for Thrust Position

9.3.1 Thrust position alarms shall be based on the thrust bearing clearance. The preferred method is to record the change in position as the rotor goes from down thrust to up thrust. Installed measured clearance may be used if the clearance as measured by the thrust probe is not available.

9.3.2 Zero thrust as indicated on the monitor is defined as the axial position of the rotor when the rotor is at normal and stable conditions. This reading is taken during baseline measurements as described in para. 8.3.

9.3.3 The monitor shall be set so that upward movement of the indication corresponds to upthrust of the rotor. Reference API 670, para. 3.5.5.5.

9.3.4 The four alarms are set based on change from the initial thrust clearances. Level 1 alarm is when the normal thrust clearance has increased by more than 10 mils (250 μm) in one direction. Level 2 alarm is when the thrust clearance has increased by more than 15 mils (375 μm) in one direction. Table 5 shows an example for a pump with normal upthrust.

9.4 Determining Alarm Points for Bearing Temperature

9.4.1 Bearing temperatures shall be set in accordance with the manufacturer's recommendation. Industry practices or plant experiences may also be considered in determining alarm points.

9.5 Alarm Settings

9.5.1 Alarm settings may be changed if the operation of the pumpset has caused a change in the parameter and the change has been evaluated and deemed acceptable.

10 ANALYSIS AND DIAGNOSTICS

10.1 Introduction

The accurate diagnosis of equipment condition is essential to maintaining operability, reducing plant down time, and increasing productivity. Diagnostics based on the analysis and interpretation of vibration data in conjunction with other equipment parameters such as flow, temperature, and pressure indicate the earliest signs of equipment degradation. Analysis and interpretation of vibration data shall be performed by someone experienced in vibration analysis techniques.

The intent of this Part is to list the types of data and the methodology used to diagnose equipment condition. This Part is not intended to take the place of established plant procedures or to delineate certain analysis methods rather to provide guidance where plant procedures do not exist or could be improved.

10.2 Data Types

Data collected for analysis shall include the following:

(a) routine steady-state data (para. 8.4)

(b) data collected based on an alarm condition (para. 8.6)

(c) data collected during transient conditions (paras. 8.2 and 8.5)

10.3 Analysis Methods

The data collected per para. 10.2 shall be analyzed using the following methods:

(a) overall vibration (amplitude trends)

(b) vibration orbit (form, precession, magnitude, and trends)

(c) vibration spectra (harmonic content, amplitude, trends, and phase)

(d) acceptance region deviations

(e) 1× and 2× vector analysis

(f) shaft position trends

(g) process data (deviations from normal values versus plant conditions and trends)

(h) machine geometry

(i) maintenance history

(j) history of similar events on similar machines

10.4 Data Analysis

An analysis is the process of reviewing data collected as specified by this standard on a machine to determine equipment condition and diagnose equipment problems. A typical analysis would include the following:

(a) Comparing current vibration, process, and equipment parameters to baseline and determining any differences.

(b) Determining if any trends are present or are developing.

(c) Reviewing equipment history for similar occurrences.

(d) Reviewing the equipment history of like machines for similar occurrences.

(e) Determining significant symptoms (para. 4)

(f) Determining probable causes of the symptoms (para. 4, i.e., determining possible equipment faults, process changes, or plant conditions that could produce the observed responses).

(g) Evaluating the probable condition of the pumpset and assessing the severity.

11 ADDITIONAL TECHNOLOGIES

The technologies described here shall be used in conjunction with vibration analysis to determine the condition of pumpsets. While one technology alone may convey some evidence of a malfunction condition, the inter-relationships between all of these technologies provides for a more complete and accurate diagnosis of the condition of the pumpset.

11.1 Thermography

11.1.1 Thermography shall be used at least before and after each refueling outage, to monitor switchgear, breakers, and control relays providing electrical power to the pumpset in accordance with ASTM E 1934-99, Guide for Examining Electrical and Mechanical Equipment with Infrared Thermography, para. 3.5.

11.1.2 See Nonmandatory Appendix B for additional information.

11.2 Lube Oil Analysis

11.2.1 Pumpset lubricating oil shall be monitored for wear debris, lubricant cleanliness (foreign material such as water and particulates), and oil chemistry in accordance with the applicable sections of ASTM D 6224, Standard Practice for In-Service Monitoring of Lubricating Oil for Auxiliary Power Plant Equipment.

11.2.2 New oil shall be sampled and tested in accordance with the recommended tests given in ASTM D 6224, Table 1, Turbine Type Oils, before being put into the pumpset bearings.

11.2.3 Used oils shall be sampled at each refueling outage, in accordance with ASTM D 6224, preferably while running or at least within 25 min of being tripped.

11.2.4 Used oils shall be tested in accordance with the recommended test methods given in ASTM D 6224, Table 2, Turbine Type Oils (if other types of oil are in service, see ASTM D 6224). Used oil that is to be left in service shall also have an oxidation stability test as specified in ASTM D 6224, Table 2, Turbine Type Oils.

11.2.5 See Nonmandatory Appendix C for additional information.

11.3 Motor Current Signature Analysis

11.3.1 Motor current signature analysis shall include the measurement of the Np × slip frequency sidebands of the line frequency component and the rotor bar and stator slot passing frequencies.

11.3.2 Motor current signature analysis shall be performed prior to each refueling outage and after every outage where maintenance work is performed on the pumpset.

11.3.3 See Nonmandatory Appendix D for additional information.

11.4 Motor Electrical Monitoring and Testing

11.4.1 The motor electrical operating parameters (current, voltage, winding temperatures, etc.) shall be monitored in accordance with the manufacturer's recommendations, industry standards and practice, and plant experience. The following parameters, as applicable, shall activate an audible alarm in the control room and shall be displayed:

(a) current
(b) phase balance
(c) winding temperature
(d) cooling water flow rate
(e) oil level
(f) winding cooler leakage

11.4.2 The motor shall be tested in accordance with the applicable parts of NEMA MG 1 Motors and Generators, para. 3.6.

11.5 Loose Parts Monitoring

11.5.1 The loose parts monitoring system shall be installed and operated in accordance with ASME OM Part 12, Loose Part Monitoring in Light-Water Reactor Power Plants, para. 3.1.

11.5.2 The loose parts monitoring system shall be checked for corresponding alarms whenever a pumpset alarm is received.

11.5.3 The loose parts monitoring system channel, which is closest to the pumpset downstream impact location, shall be monitored when starting a pumpset after maintenance.

11.5.4 See Nonmandatory Appendix E for additional information.

12 OTHER

12.1 Calibrations

Calibrations shall be performed per the manufacturer's recommendations and the plant maintenance program. Consideration of the performance of the sensor (e.g., bias current and trend of 60 Hz frequency component) may be used in determining calibration requirements.

12.2 Quality

The instrumentation, computer systems, documentation, and data described in this standard are considered non-nuclear safety as described in the plant's QA plan. Normal industry good practices shall be followed in calibration, controlling, backing up, and storing documentation and data.

PART 24
NONMANDATORY APPENDIX A
References

Below is a list of useful documents.

ISO 2372, Mechanical Vibration of Machines with Operating Speeds From 10 to 200 rev/s: Basis for Specifying Evaluation Standards

ISO 2373, Mechanical Vibration of Certain Rotating Electrical Machinery With Shaft Heights Between 80 and 400 mm: Measurement and Evaluation of the Vibration Severity

ISO 2954, Mechanical Vibration of Rotating and Reciprocating Machinery: Requirements for Instruments for Measuring Vibration Severity

ISO 3945, Mechanical Vibration of Large Rotating Machines With Speed Range From 10 to 200 rev/s: Measurement and Evaluation of Vibration Severity In Situ

ISO 7919/1, Mechanical Vibration of Nonreciprocating Machines: Measurements on Rotating Shafts and Evaluation, Part 1 General Guidelines

ISO 10816, Mechanical Vibration Evaluation of Machine Vibration by Measurements of Nonrotating Parts

Publisher: International Organization for Standardization (ISO), 1 rue de Varembé, Case Postale 56, CH-1211, Genève 20, Switzerland/Suisse

PART 24
NONMANDATORY APPENDIX B
Thermography

Thermography is the use of noncontact infrared technology to measure the surface temperature of equipment and can be used to detect faults in machinery, which create localized temperature changes. Thermography as a trend tool can be used for the early detection of developing equipment problems and identification of possible problem areas once a fault has developed.

(a) In electrical systems, such faults include the following:

(1) loose or corroded connections
(2) overloads
(3) phase imbalance
(4) short circuits
(5) mismatched or misinstalled components

Electrical system exceptions can be detected and identified using absolute temperature criteria published in ANSI, IEEE, and NEMA published standards.

(b) In mechanical systems, typical faults include the following:

(1) improper lubrication
(2) misalignment
(3) worn components
(4) improper loading

PART 24
NONMANDATORY APPENDIX C
Lube Oil Analysis

Monitoring of lubricating oil in a pumpset can help to minimize the high cost of oil changes and unplanned shutdowns. The cost of changing the oil in the pumpsets covered by this standard may be significantly higher than for other applications, because the oil may be slightly radioactive. An effective lubricating oil monitoring program, in accordance with ASTM D 6224, Standard Practice for In-Service Monitoring of Lubricating Oil for Auxiliary Power Plant Equipment, may be used to perform oil changes based on test results rather than on the basis of service time or calendar time. Such a program is also intended to guard against excessive component wear, oil degradation, or contamination, thereby minimizing the potential of catastrophic machine problems that are more likely to occur in the absence of such a monitoring program.

The analysis tests specified are for oils that are considered turbine type. This type of oil is commonly used in pumps and motors. Service oils that are not turbine type shall have tests performed, as specified in ASTM D 6224, that are appropriate for their oil type. PAO synthetic oils, if used, shall be tested with the same test methods specified for turbine-type oils; however, the oxidation stability test results may require vendor interpretation.

New oil shall be prefiltered in accordance with para. 7.3 of ASTM D 6224.

PART 24
NONMANDATORY APPENDIX D
Motor Current Signature Analysis

Motor current analysis is a monitoring tool for induction motor driven equipment that gives information to diagnose electrical and mechanical conditions of the rotor. It is an in-service analysis of the frequency spectrum of the motor current made with the motor operating at normal load without interfering with the function of the driven machine or process.

Voltage signals from a current transformer shunt in one phase of the power supply are analyzed using a frequency spectrum. Rotor winding analysis is done by comparing the amplitudes of the sideband components with the amplitude of the line frequency component. The sideband amplitudes become larger as damage to the rotor progresses. The amplitude and frequency of the sidebands are used to assess the number and severity of broken rotor bars.

Levels of static and dynamic eccentricity of the rotor within the stator are determined from the rotor bar passing frequency and the running speed sideband amplitudes in the motor current signal. Data must be compensated for machine load and process parameter changes. With experience, an accurate determination of the condition of the rotor can be determined.

(a) Motor current analysis is probably the most effective on-line tool for detecting the following:

(1) cracked or broken rotor bars
(2) cracked motor end rings
(3) high resistance joints
(4) casting porosities or blow holes in aluminum die-cast rotors
(5) poor joint brazing in fabricated rotors
(6) rotor winding problems in slip-ring induction motors

(b) Motor current analysis can also detect many of the motor mechanical problems such as the following:

(1) stationary or rotating air gap irregularities
(2) unbalanced magnetic pull
(3) mechanical unbalance
(4) bent shaft, thermal bow
(5) out-of-round stator or bearings

It is not the best detector of many of the above mechanical problems, but it provides support for motor vibration analysis.

PART 24
NONMANDATORY APPENDIX E
Loose Parts Monitoring

Data from the loose parts monitoring system is helpful for diagnosing the following conditions:

(a) missing parts of an impeller

(b) damage from a loose part going through a pumpset

(c) pumpset internal loose parts or severe mechanical looseness

(d) pumpset rubbing

(e) pumpset cavitation

(f) a pumpset vibration alarm caused by thermal expansion during heat up or cool down

(g) pumpset flow–induced vibration

PART 25

PART 25
Performance Testing of Emergency Core Cooling Systems in Light-Water Reactor Power Plants

1 INTRODUCTION

1.1 Scope

This Part establishes the requirements for inservice testing to assess the operational readiness of Emergency Core Cooling Systems, including those systems required for long-term decay heat removal, used in Light-Water Reactor (LWR) power plants.

The Emergency Core Cooling Systems covered are those 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.

This Part establishes test methods, test intervals, parameters to be measured and evaluated, acceptance criteria, corrective actions, and records requirements for the purpose of assessing integrated system performance.

1.2 Owner's Responsibility

This Part requires development of a performance testing program that verifies the Emergency Core Cooling System (ECCS) functions in accordance with the design basis over the life of the plant. The Owner shall establish this program through a process of the following five parts:

(a) Identify ECCS performance requirements from licensing and design basis documentation (see para. 5).

(b) Identify testable ECCS characteristics that represent performance requirements (see para. 6).

(c) Establish test acceptance criteria for each ECCS characteristic (see para. 7).

(d) Develop test procedures that include test acceptance criteria and test frequencies, and perform required testing, inspections, and engineering analysis (see para. 8).

(e) Evaluate test data, document results, and implement corrective action as appropriate (see paras. 9 and 10).

Apply the appropriate quality assurance requirements to this program.

Ensure that nuclear safety is maintained by developing a test program within the bounds of the plant's design basis. Consider the required test conditions and the potential consequences of the testing when developing the test program. In the event that a test would be impractical or cause detrimental interactions, engineering evaluation or analysis is allowed in lieu of testing. Additional guidance is provided in para. 8.

Procedures or test programs established for other purposes may be used to satisfy testing requirements of this Standard to the extent that they meet the requirements of this Standard.

2 DEFINITIONS

The following list of definitions is provided to ensure a uniform understanding of selected terms used in this Part.

acceptance criteria: specified limits placed on characteristics of an item, process, or service defined in codes, standards, or other required documents.

accuracy: the closeness of agreement between a measured value and the true value.

actuation levels: a response to defined plant conditions that will control or actuate a desired set of components.

borated water supply tank (BWST): a storage tank containing borated water inventory for Pressurized Water Reactor (PWR) ECCS pump suction during the injection phase.

characteristic: a variable or attribute that can be verified by direct measurement or data reduction.

component: an item such as a vessel, pump, valve, piping products, or core support viewed as an entity for purposes of reporting or analyzing.

condensate storage tank (CST): a storage tank containing water inventory for Boiling Water Reactor (BWR) ECCS pump suction.

containment spray: a system to control containment pressure and temperature and to remove containment heat following accident conditions.

design bases: information that identifies the specific functions to be performed by a structure, system, or component of a facility, and the specific values or ranges of values chosen for controlling parameters as reference bounds for designs.

emergency core cooling system (ECCS): an automatic or manual safety system credited in the plant 10 CFR 50.46 (Acceptance Criteria for Emergency Core Cooling Systems for Light-Water Nuclear Power Reactors) analysis, or equivalent analysis, for injecting coolant to the reactor core or removing heat directly from the core coolant.

engineered safety features actuation system (ESFAS): a system that responds to input parameters to actuate required components in accordance with specified actuation levels.

response time: time elapsed from when the process exceeds a setpoint until the component achieves the required response.

support system: those systems that are necessary for the ECCS to perform its intended function.

system: an assembly of items whose functions and limitations are defined in design or system specification documents.

3 REFERENCES

The following is a list of publications referenced in this Part.

Regulatory Guide 1.1, Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal System Pumps (Safety Guide 1), U.S. Nuclear Regulatory Commission, November 1970

Title 10, Code of Federal Regulations, Part 50, Section 50.46, Acceptance Criteria for Emergency Core Cooling Systems in Light Water Nuclear Power Reactors

Publisher: Superintendent of Documents, United States Government Printing Office, Washington, DC 20402

4 ESTABLISH SYSTEM TESTING BOUNDARIES

Establish the system test boundaries for all emergency core cooling systems (ECCS) as defined in para. 2, such as low-pressure injection, high-pressure injection, passive injection, pumped recirculation, core spray, and automatic depressurization systems. The test boundary shall include all equipment required to perform the ECCS function of delivering water from the source to the reactor vessel or removing heat directly from the core coolant.

The test boundaries shall include portions of the following decay heat removal systems only when credited as ECCS or when they directly affect ECCS operation:

(a) normal feedwater
(b) auxiliary or emergency feedwater
(c) steam generator heat removal (PWR)
(d) containment air cooling
(e) isolation condenser (BWR)
(f) reactor core isolation cooling (BWR)
(g) containment spray
(h) suppression pool cooling (BWR)
(i) standby liquid control (BWR)
(j) normal plant shutdown decay heat removal

For example, establishing the test boundary shall consider the interaction of the containment spray pumps with high head safety injection (SI) pump net positive suction head (NPSH) when the pumps simultaneously take suction from the low head SI pump discharge in PWRs.

Support system testing, including ESFAS or ECCS actuation logic testing, is not within the scope of this Part. It is assumed that any ECCS support system is tested by other procedures and is able to perform its intended function.

5 IDENTIFY SYSTEM PERFORMANCE REQUIREMENTS

Identify system performance requirements for ECCS within the established test boundaries. Input parameters derived from safety analyses performed to meet the requirements of para. 6(a), or equivalent, define the ECCS performance requirements. Examples include core-delivered flow, ECCS fluid temperature, and time to reach full pumped flow after ECCS actuation. Performance requirements shall be consistent with the plant licensing and design basis, including relevant licensing commitments that limit, modify, or clarify ECCS operating requirements.

In some cases, it is not practical to directly test each of the performance requirements. In these instances, develop testable system characteristics that can be used to verify performance requirements.

6 IDENTIFY TESTABLE CHARACTERISTICS THAT REPRESENT PERFORMANCE REQUIREMENTS

Identify testable system characteristics that represent the ECCS performance requirements. Use source information that defines ECCS characteristics, which includes the following:

(a) nuclear steam supply system (NSSS) design specifications
(b) architect-engineer specifications
(c) Final Safety Analysis Report (FSAR)/Updated Safety Analysis Report (USAR)
(d) Safety Evaluation Report/Supplemental Safety Evaluation Reports
(e) design calculations
(f) system descriptions
(g) design basis documentation
(h) reload documentation
(i) vendor correspondence
(j) preoperational tests
(k) design change documentation

6.1 System Characteristics

System characteristics are variables or attributes that can be determined by direct measurement or data reduction. For example, pump-developed head and system resistance are the system characteristics that can be used to verify the performance requirement of core-delivered flow.

The values of some system characteristics cannot be directly measured but can be verified by data reduction. Pump total dynamic head and system resistance are examples of characteristics that cannot be directly measured but can be calculated from other directly measured parameters, such as pressure and flow rate.

6.1.1 Component Characteristics. Component characteristics that affect system level performance shall be included as system characteristics. An example is pump performance required to deliver design flow to the reactor coolant system (RCS) within a defined time interval after a loss-of-coolant accident (LOCA). Also, heat removal for ECCS heat exchangers is a system characteristic for some ECCS designs.

6.1.2 Instrumentation and Control (I & C) Characteristics. Instrumentation and Control (I & C) characteristics that affect system-level performance shall be included as system characteristics. These include indication and control of system parameters such as flow, pressure, level, and temperature.

6.1.3 ECCS Logic Characteristics. ECCS logic characteristics shall be included as system characteristics. ECCS logic is any permissive or interlock that initiates or aligns ECCS fluid systems or mechanical devices. ECCS logic does not include ESFAS or ECCS actuation logic. Examples of ECCS logic are the following:

(a) logic that prevents unintentional overriding of ECCS operation such as defeating noncritical trips during emergency actuation and confirmatory signals to valves

(b) logic intended to prevent exceeding design limits such as logic-controlled flow limiters

(c) logic that causes ECCS components to actuate via an ESFAS or ECCS actuation signal

(d) logic for transfer of pump suction from the BWST to the containment sumps on a BWST low-level signal (PWR)

(e) interlocks such as the logic for motor-operated valves that isolate the decay heat removal system suction lines during normal operation and the safety injection accumulators before plant shutdown (PWR)

(f) logic for transfer of pump suction from the CST to the containment suppression pool (BWR)

(g) interlocks such as the pressure-permissive logic for injection valves on low-pressure injection systems (BWR)

(h) logic for ECCS injection path selection (BWR)

(i) logic for system realignment to accident mode from any nonsafety or secondary operating mode

6.2 PWR Characteristics

Identify ECCS system characteristics for the passive injection, pumped injection, and pumped recirculation ECCS operating modes. Paragraphs 6.2.1 through 6.2.3 provide some examples of system characteristics for the three operating modes. These examples are not to be considered all-inclusive.

6.2.1 Passive Injection Mode Characteristics. A system characteristic associated with the passive injection mode is discharge flow path resistance from the safety injection accumulators to the RCS.

6.2.2 Pumped Injection Mode Characteristics. System characteristics associated with the pumped injection mode are the following:

(a) pump discharge flow path overall resistance and balanced branch line resistance for all cold and hot leg injection paths

(b) for injection pump and driver operation

(1) NPSH for pump performance under worst-case system conditions

(2) pump total dynamic head versus flow

(3) pump response time (time to reach rated flow)

(4) pump drivers not tripping under worst-case flow conditions

(c) pump minimum flow path flow rate under both individual and combined pump operation

(d) integrated ECCS operation in conjunction with other systems in response to ESFAS actuation with and without offsite power

6.2.3 Pumped Recirculation Mode Characteristics. System characteristics associated with the pumped recirculation mode are the following:

(a) NPSH available is greater than that required at accident conditions (such as temperature, pressure, flow, and blockage), as discussed in para. 6(b)

(b) pump discharge flow path overall resistance and balanced branch line resistance for all cold and hot leg injection paths not addressed in para. 6.2.2

(c) operation of each pump in all design operating modes not addressed in para. 6.2.2, including pump drivers that will not trip under worst-case flow conditions

(d) higher head pumps that can be aligned for suction from the lower head pumps and operate acceptably in those plants that use this scheme in the pumped recirculation mode

(e) heat removal from ECCS heat exchangers

(f) transfer of pump suction from the BWST to the containment sump

6.3 BWR Characteristics

Identify ECCS system characteristics for the high-pressure injection, depressurization, low-pressure injection, and long-term decay heat removal modes. Paragraphs 6.3.1 through 6.3.4 provide some examples of system characteristics for the four operating modes. These examples are not to be considered all-inclusive.

6.3.1 High-Pressure Injection Mode Characteristics. System characteristics associated with high-pressure injection mode are the following:

(a) discharge flow path resistance for all injection paths

(b) for injection pump and driver operation

(1) NPSH for pump performance under worst-case system conditions, including strainer head losses

(2) pump total dynamic head versus flow

(3) pump response time (time to reach rated flow)

(4) pump drivers not tripping under worst-case flow conditions

(c) pump minimum flow path flow rate

(d) integrated ECCS operation in conjunction with other systems in response to ECCS actuation with and without offsite power

(e) transfer of pump suction from the CST to the suppression pool

6.3.2 Depressurization Mode Characteristics. System characteristics associated with the depressurization mode are the following:

(a) blowdown mass flow rate

(b) initiation logic operation

6.3.3 Low-Pressure Injection Mode Characteristics. System characteristics associated with the low-pressure injection mode are the following:

(a) discharge flow path resistance for all injection paths

(b) for injection pump and driver operation

(1) NPSH for pump performance under worst-case system conditions, including strainer head losses

(2) pump total dynamic head versus flow

(3) pump response time (time to reach rated flow)

(4) pump drivers not tripping under worst-case flow conditions

(c) pump minimum flow path flow rate under both individual and combined pump operation

(d) integrated ECCS operation in conjunction with other systems and divisions, where divisional interaction exists, in response to ECCS actuation with and without offsite power

6.3.4 Long-Term Decay Heat Removal Mode Characteristics. System characteristics associated with long-term postaccident heat removal are the following:

(a) flow resistance for all heat removal paths

(b) for heat removal pump and driver operation

(1) NPSH for pump performance under worst-case system conditions, including strainer head losses

(2) pump total dynamic head versus flow

(3) pump response time (time to reach rated flow)

(4) pump drivers not tripping under worst-case flow conditions

(c) pump minimum flow path flow rate under both individual and combined pump operation

(d) ECCS heat exchanger heat removal

7 ESTABLISH CHARACTERISTIC ACCEPTANCE CRITERIA

Establish acceptance criteria for each system characteristic derived in accordance with para. 6. Each system characteristic has analysis limits that are documented in the plant design or licensing basis. Develop test acceptance criteria from these limits that account for the following:

(a) differences between analysis and test, considering system configuration and boundary or process fluid conditions. Since ECCS testing under accident conditions may be impractical, acceptance criteria must be developed by associating practical test conditions to accident analysis limits. An example is system flow or flow balance criteria derived from small break LOCA analysis, but that are verified under zero back pressure, nonaccident conditions.

(b) test instrument loop accuracy. Accomplish this by adjusting either the measured data or the analysis limits.

Refer to Nonmandatory Appendix B for guidance on developing acceptance criteria and dealing with test instrument accuracy.

8 DEVELOP TEST PROCEDURES AND PERFORM TESTING, INSPECTIONS, AND ENGINEERING ANALYSES

Develop and approve test procedures to verify acceptance criteria derived in accordance with para. 7 are met. Organizations responsible for maintaining the design basis shall participate in developing test-acceptance criteria and procedures.

Use available operating experience information to develop and perform test procedures. Nonmandatory Appendix A summarizes ECCS operating experience information. Nonmandatory Appendix A, the individual Licensee Event Reports (LERs), and Information Notices (INs) give additional insights into ECCS operation and testing.

Perform testing at plant conditions as close as practical to those expected during ECCS operation. Identify test conditions that are different from accident conditions (e.g., temperature and pressure) when testing at accident conditions is not practical or could potentially damage equipment. Perform analysis to account for differences between accident and test conditions. Consider test initial conditions for the plant, especially reactor, fuel, and support systems to avoid detrimental interactions during the test.

Although this Part does not require simultaneous testing of all system components, subsystems, and their support systems, place emphasis on integrating the testing where practical. A logical combination of several separate tests is acceptable. It is permissible to devise separate subsystem and component tests to collect data for specific characteristics. Analyze these test results to correlate them to results that would have been obtained under simultaneous testing to ensure all interfaces are properly tested and verified.

Data from plant transients or inadvertent system initiations may be used if necessary analyses and supporting documentation are available.

Engineering evaluations may be performed if integrated testing is not practical. Consider the required test conditions and the potential consequences of the testing in the evaluation of practicality. For example, in BWRs, performing a high-pressure core injection system flow test with flow to the vessel may cause undesired thermal stresses to the vessel, internals, or the fuel due to the required test conditions for a turbine-driven pump. Use testing rather than evaluation wherever possible.

This Part does not identify nonsystem-level testing of ECCS components, instrumentation, and controls. It is assumed that applicable codes and standards that define such testing have been implemented. Verifying test acceptance criteria in accordance with this Part does not provide relief from meeting more limiting criteria associated with such codes and standards.

If tests are performed at conditions different from the calibrated condition of the instruments, recalibrate the instruments for the test conditions, use alternate instruments, or adjust the data to compensate for the difference.

8.1 Preoperational Testing

No specific requirements apply to preoperational testing that are beyond those stipulated in this Part for inservice testing.

8.2 Inservice Testing

Develop and conduct tests to measure ECCS system performance. The test results are used to determine that the system, component, I & C, and ECCS logic characteristics meet associated acceptance criteria.

8.2.1 PWR Inservice Testing. Paragraphs 8.2.1.1 through 8.2.1.3 provide requirements for inservice testing of some of the PWR system characteristics described in paras. 6.2.1 through 6.2.3.

8.2.1.1 Passive Injection Mode. Test the system characteristic of discharge flow path resistance from the safety injection accumulators to the RCS. Perform this test at a pressure sufficient to allow opening of all in-line check valves to their design basis flow position. See para. 8.3 for specific test frequency requirements and exceptions. See Nonmandatory Appendix B, para. B-2 for technical guidance.

8.2.1.2 Pumped Injection Mode. Inject water from the BWST or other appropriate source into the reactor vessel through each required injection leg and pump combination as allowed by plant design. Test each ECCS train under cold operating conditions. The reactor vessel may be open and flooded during the testing, with the RCS pressure at essentially atmospheric pressure. There is no requirement to control BWST water temperature.

(a) Test pump discharge flow path overall resistance and balanced branch line resistance for all cold and hot leg injection paths. Establish system flows high enough to allow determination of flow path resistance. Refer to Nonmandatory Appendix B, paras. B-5 through B-7 for guidance.

(b) Test the system characteristic of injection pump operation. Verify pump total dynamic head versus flow, using a five-point (or greater) test, distributed between minimum and maximum expected flow rate. Note that testing in accordance with component level pump codes might not verify this system characteristic due to differences in testing method and acceptance criteria. Refer to Nonmandatory Appendix B, para. B-4 for further guidance.

(c) Test pump minimum flow under both individual and combined pump operation. Verify that pumps sharing a common discharge or minimum flow path do not have operating characteristics sufficiently different to cause a pump to run outside its acceptable operating range. Refer to Nonmandatory Appendix A for additional information.

(d) Test integrated ECCS operation in conjunction with other systems in response to ESFAS actuation with and without offsite power. For at least one of these tests, deliver simultaneous flow from all trains to the reactor vessel for sufficient duration to ensure that no adverse system interactions exist. See para. 8.3 for specific test frequency requirements and exceptions for testing with simultaneous flow from interacting trains to the RCS. Refer to Nonmandatory Appendix A for additional information.

(e) Test for adequate NPSH and acceptable pressure drops in suction lines and valves from the sources to the pump suction under maximum flow conditions. Verify that vortex formation is minimized. Since these tests are associated with the suction flow path only, use full flow test return paths that bypass the reactor vessel if available. This avoids any undesirable impact from injecting directly to the reactor vessel. See para. 8.3 for specific test frequency exceptions for vortex formation testing. Refer to Nonmandatory Appendix A for additional information.

8.2.1.3 Pumped Recirculation Mode

(a) Test the system characteristic of NPSH by taking suction from the containment recirculation sump. These tests should include transfer of pump suction between the BWST and the containment sump. Verify that vortex formation is minimized and that acceptable pressure drops exist across sump screens (clean and with postulated blockage), suction lines, and valves from the sump to the pump suction. Temporary sump modifications to provide adequate sump capacity for pump operation

are acceptable. Since these tests are associated with the suction flow path only, use full flow test return paths that bypass the reactor vessel if available. This avoids any undesirable impact from injecting directly to the reactor vessel.

Where actual plant testing is impractical, scale model testing of containment recirculation sumps, screens, and surrounding areas may be used. Include in the scale model design a scaling analysis that demonstrates that the test data will accurately reflect the actual system characteristics. Compare the inlet loss coefficient across the sump screens and sump intake piping to analytically determined values and verify pump NPSH adequacy. If the scale model does not simulate the flow path from the sump to the respective pumps, an analytical evaluation of hydraulic losses in the flow path is acceptable in lieu of testing. See para. 8.3 for specific test frequency exceptions.

(b) Verify by inspection or other means that an unobstructed pumped recirculation mode suction flow path will exist. An unobstructed flow path is free of flow path restrictions or debris that could adversely impact system function. Inspect containment areas in the postulated debris transport routes to the sump, the ECCS sump area inside the debris barrier, and the flow path from the ECCS sump to the respective pumps.

(c) Test pump discharge flow path overall resistance and balanced branch line resistance for all cold and hot leg injection paths not addressed in para. 8.2.1.2. This may be verified with pump suction aligned from alternate sources with appropriate analytical justification. Refer to Nonmandatory Appendix B, paras. B-5 through B-7 for guidance.

(d) Test that higher head pumps can be aligned for suction from the lower head pumps and operate acceptably in those plants that use this scheme in the pumped recirculation mode.

8.2.2 BWR Inservice Testing. Paragraphs 8.2.2.1 through 8.2.2.4 provide requirements for inservice testing of some of the system characteristics described in paras. 6.3.1 through 6.3.4.

8.2.2.1 High-Pressure Injection Mode. Inject water into the reactor vessel through each required injection path and pump combination as allowed by plant design. Test each ECCS train under cold or hot operating conditions as practical. The reactor vessel may be open and flooded during testing.

(a) Test discharge flow path resistance for all injection paths. Establish system flows high enough to allow determination of flow path resistance. Refer to Nonmandatory Appendix B, para. B-4 for guidance.

(b) Test the system characteristic of injection pump operation. Verify pump total dynamic head versus flow at minimum, maximum achievable, and design basis flow rates. Note that testing in accordance with component-level pump codes might not verify this system characteristic due to differences in testing method and acceptance criteria. Refer to Nonmandatory Appendix B, para. B-3 for further guidance.

(c) Test pump minimum flow under both individual and combined pump operation. Verify that pumps sharing a common discharge or minimum flow path do not have operating characteristics sufficiently different to cause a pump to run outside its acceptable operating range. Refer to Nonmandatory Appendix A for additional information.

(d) Test integrated ECCS operation in conjunction with other systems in response to ECCS actuation with and without offsite power. For at least one of these tests, deliver flow to the reactor vessel for sufficient duration to ensure that no adverse system interactions exist. See para. 8.3 for specific test frequency exceptions for testing with simultaneous flow from interacting divisions to the reactor vessel. Refer to Nonmandatory Appendix A for additional information.

(e) Test for adequate NPSH and acceptable pressure drops across suction strainers, suction lines, and valves from the sources to the pump suction. These tests should include transfer of pump suction between the CST and the suppression pool. Verify that vortex formation is minimized. Since these tests are associated with the suction flow path only, use full flow test return paths that bypass the reactor vessel if available. This avoids any undesirable impact from injecting directly to the reactor vessel. See para. 8.3 for specific test frequency exceptions for vortex formation testing. Refer to Nonmandatory Appendix A for additional information.

8.2.2.2 Depressurization Mode

(a) Test the system characteristic of blowdown mass flow by opening the Automatic Depressurization System (ADS) valves and determining the mass flow rate. This may be accomplished by opening individual relief valves in any mode of operation and measuring appropriate parameters to obtain a mass flow rate.

Scale model or prototype testing of ADS valves to determine mass flow rate may be used in place of actual plant testing. An analytical evaluation is acceptable in lieu of testing if the scale model or prototype testing does not simulate discharge to the suppression pool. In the absence of verifying mass flow rate, ensure by other means that an unobstructed flow path exists. See para. 8.3 for specific test frequency exceptions.

(b) Test the ADS initiation logic by verifying operation from the ECCS actuation signal through the valve actuator. Valve opening may be verified via other testing such as the relief mode operation.

8.2.2.3 Low-Pressure Injection Mode. Inject water into the reactor vessel through each required injection path and pump combination. Test each ECCS train under cold or hot operating conditions as practical. The reactor vessel may be open and flooded during testing.

(a) Test discharge flow path resistance for all injection paths. Establish system flows high enough to allow determination of flow path resistance. Refer to Nonmandatory Appendix B, para. B-4 for guidance.

(b) Test the system characteristic of injection pump operation. Verify pump total dynamic head versus flow at minimum, maximum achievable, and design basis flow rates. Note that testing in accordance with component-level pump codes might not verify this system characteristic due to differences in testing method and acceptance criteria. Refer to Nonmandatory Appendix B, para. B-3 for further guidance.

(c) Test pump minimum flow under both individual and combined pump operation. Verify that pumps sharing a common discharge or minimum flow path do not have operating characteristics sufficiently different to cause a pump to run outside its acceptable operating range. Refer to Nonmandatory Appendix A for additional information.

(d) Test integrated ECCS operation in conjunction with other systems and divisions, where divisional interaction exists, in response to ECCS actuation with and without offsite power. For at least one of these tests, deliver flow to the reactor vessel for sufficient duration to ensure that no adverse system interactions exist. See para. 8.3 for specific test frequency exceptions for testing with simultaneous flow from interacting divisions to the reactor vessel. Refer to Nonmandatory Appendix A for additional information.

(e) Test for adequate NPSH and acceptable pressure drops across suction strainers, suction lines, and valves from the sources to the pump suction. Verify that vortex formation is minimized. Since these tests are associated with the suction flow path only, use full flow test return paths that bypass the reactor vessel if available. This avoids any undesirable impact from injecting directly to the reactor vessel. See para. 8.3 for specific test frequency exceptions for vortex formation testing. Refer to Nonmandatory Appendix A for additional information.

8.2.2.4 Long-Term Decay Heat Removal Mode. Test flow through each required decay heat removal path and pump combination. Test each decay heat removal train under cold or hot operating conditions as practical. The reactor vessel may be open and flooded during testing.

(a) Test flow resistance for all decay heat removal paths. Establish system flows high enough to determine flow resistance. Refer to Nonmandatory Appendix B, para. B-4 for guidance.

(b) Test the system characteristic of decay heat removal pump operation. Verify pump total dynamic head versus flow at minimum, maximum achievable, and design basis flow rates. Note that testing in accordance with component-level pump codes might not verify this system characteristic due to differences in testing methods and acceptance criteria. Refer to Nonmandatory Appendix B, para. B-3 for further guidance.

(c) Test pump minimum flow under both individual and combined pump operation. Verify that pumps sharing a common discharge or minimum flow path do not have operating characteristics sufficiently different to cause a pump to run outside its acceptable operating range. Refer to Nonmandatory Appendix A for additional information.

(d) Test for adequate NPSH and acceptable pressure drops across suction strainers, suction lines, and valves from the sources to the pump suction. Verify that vortex formation is minimized. Since these tests are associated with the suction flow path only, use full flow test return paths that bypass the reactor vessel if available. This avoids any undesirable impact from injecting directly to the reactor vessel. See para. 8.3 for specific test frequency exceptions for vortex formation testing. Refer to Nonmandatory Appendix A for additional information.

(e) Test heat exchanger ECCS decay heat removal capability.

8.3 Testing Frequency

(a) Conduct ECCS inservice testing described in para. 8.2 at a 5-year ± 25% time interval. The test interval may be extended up to 10 years, provided that a valid basis for this change is developed and documented. A valid basis for changing the interval shall consist of a documented evaluation of margin between acceptance criteria and system performance, system performance data, and modification and maintenance history. Allowable exceptions to this time interval are described below.

(1) Conduct the integrated ECCS test with simultaneous flow from all trains (PWR) [para. 8.2.1.2(d)] or interacting divisions (BWR) [paras. 8.2.2.1(d) and 8.2.2.3(d)] to the reactor vessel at a 10-year ± 25% time interval.

(2) ECCS accumulator testing (PWR) (para. 8.2.1.1), containment sump testing (PWR) [para. 8.2.1.3(a)], and suction vortex formation testing [paras. 8.2.1.2(e), 8.2.1.3(a), 8.2.2.1(e), 8.2.2.3(e), and 8.2.2.4(d); (BWR and PWR)] need only be performed following any modification that affects the corresponding performance requirements of para. 5. This exception is allowed, provided there is objective evidence that the requirements of these paragraphs have been met at least once.

(3) Provided there is objective evidence that the requirements have been met at least once, perform the applicable inspections in para. 8.2.3(a)(2) when containment activity or system maintenance/modifications could affect the ability to meet system performance requirements defined in para. 5 due to debris generation.

(4) Testing of the ADS valves (BWR) in para. 8.2.2.2(a) need only be performed following any modification that affects the corresponding performance requirements of para. 5, provided there is objective evidence that the requirements of this paragraph have been met at least once.

(b) Perform the applicable portions of para. 8.2 prior to returning the system to service following replacement, repair, maintenance, or modification to ECCS components or systems, which could affect the ability to meet system performance requirements defined in para. 5. Examples of such changes include the following:

(1) replacing valve or valve internals

(2) changing valve throttled position, including limit switch stop settings

(3) replacing or trimming the pump rotating element

(4) changing system logic

(5) changing the ECCS flow path

(c) Credit may be taken for testing performed in accordance with other test programs meeting the requirements of this Standard.

9 EVALUATE TEST DATA

If test results fail to meet acceptance criteria, take corrective action. Corrective action shall consist of either of the following:

(a) Perform appropriate remedial actions on the nonconforming component or system, followed by retest.

(b) Perform evaluations to disposition components or systems not conforming. These evaluations shall include revision of the design or design basis such that the measured data meet revised acceptance criteria, and may require revision of the associated licensing basis.

10 PREPARE DOCUMENTATION

Document the basis for selecting design characteristics, test procedures, and acceptance criteria. Retain testing program procedures, results, deficiencies, evaluations, and corrective actions.

PART 25
NONMANDATORY APPENDIX A
Lessons Learned From ECCS Operating Experience

Table A-1 contains operating experience information associated with light-water reactor ECCS. The information focuses on events where improved ECCS testing might prevent the ECCS from becoming degraded or unable to perform its intended safety functions. Table A-1 summarizes lessons learned from this information, which should be used in developing the test program. More detailed information is also available in the individual Regulatory Guides (RGs), Licensee Event Reports (LERs), and Information Notices (INs) identified below.

The PWR ECCS includes a borated water supply; low, intermediate, and high-head injection pumps; passive safety injection accumulators (core reflood tanks); heat exchangers; and associated flow paths. The BWR ECCS includes a condensate storage tank, suppression pool, automatic depressurization, low- and high-pressure injection and spray pumps, heat exchangers, and associated flow paths.

Table A-1 does not include information on the following decay heat removal systems or methods: feedwater, suppression pool cooling (BWR), containment spray, containment cooling, auxiliary or emergency feedwater, steam generator heat removal (PWR), feed and bleed heat removal (PWR), and containment air cooling.

Based on their proximate causes, the events of Table A-1 are organized according to the following eight categories:

(a) inadequate instrumentation

(b) incorrect pump net positive suction head

(c) pump minimum flow recirculation line problems

(d) pump gas binding problems

(e) incorrect emergency diesel generator electrical loading

(f) inadequate testing frequency

(g) inadequate acceptance criteria

(h) inadequate postmodification testing

Table A-1 ECCS Operating Experience Information

Category	Issue	Source(s)	Lessons Learned
ECCS instrumentation inadequacies	Incorrect calibration for test conditions	LER 50-397/ 92-014-01	Test instruments must be calibrated for expected fluid temperature during testing
	Improper orifice plate flow coefficients	LER 50-344/ 91-10-01	Use pump header flow measurements to confirm total flow, and use branch line flow measurements for balancing individual injection line flow rates
	Incorrect orifice plate K-factors and flow transmitter calibration	LER 50-272/90-14, LER 50-244/89-07, LER 50-259/ 88-07-01	Verify ECCS orifice plate K-factors are correct, and correlate SI system flow transmitter calibration data with the installed flow orifice plates
	Incorrectly installed and deformed orifice plates	IN 90-65, IN 93-13	Verify beveled edge orifice plates are in the correct orientation (direction); check for flow and differential pressure induced deformation in orifices used as flow restrictors to limit flow rates
	Inadequate response time testing of instruments with pressure-dampening devices	IN 92-33	Include existing ECCS pressure-sensing instrument snubbers in the test configuration when testing instrument response times
Pump net positive suction head	Insufficient net positive suction head	IN 88-74	Address the effects of potential inadequate NPSH when ECCS pumps are aligned to simultaneously take suction from the discharge of other pumps (piggyback alignment for PWRs)
	Inadequate surveillance of containment sump	IN 96-10	Three of four sumps contained debris in the bottom below the suction pipe for ECCS systems. Two of the four lines taking suction from the sump were partially blocked.
	Insufficient net positive suction head due to strainer plugging	NRC Bulletin 96-03, RG 1.82 Rev 2, NUREG/CR-6224	Address the effects of potential inadequate suction to the ECCS pumps when aligned to take suction from the containment sump
	High pump suction pressure	LER 50-327/91-23	Verify maximum ECCS pump suction pressure during piggyback alignment is not excessive. Excessive pressure might lift relief valves and result in loss of coolant outside containment.
Pump minimum flow recirculation line problems	Deadheading one of two ECCS pumps in systems having a common miniflow recirculation line for both pumps	IN 87-59	Consider the potential for pump operation near shutoff head causing deadheading of the weaker pump when pumps operate in parallel alignment
	Miniflow recirculation line flow capacity	IN 87-59	Verify ECCS pump miniflow recirculation lines have adequate flow capacity for multiple pump operation

Table A-1 ECCS Operating Experience Information (Cont'd)

Category	Issue	Source(s)	Lessons Learned
Pump gas binding	Accumulator nitrogen binding	IN 89-67	Minimize the effects of nitrogen injection into the RCS when performing full-flow RCS accumulator check valve testing by (a) testing the valves after refueling rather than during shutdown prior to refueling (b) determining if it is appropriate to test the check valves with fuel in the reactor vessel (c) reducing accumulator nitrogen pressure or remove the reactor vessel head
	Hydrogen binding	IN 88-23 Supplement 3, LERs 50-455/91-12, 455/90-35, 213/90-08	Periodically check the ECCS for gas buildup and vent the systems; this is in addition to any periodic TS required venting of pump casing and discharge piping
Incorrect Emergency Diesel Generator (EDG) electrical loading	EDGs do not respond to all LOOP and LOCA sequences	IN 93-17	Test EDG starting and loading logic during ECCS testing to verify they will respond correctly to all credible LOOP and LOCA sequences. This includes EDG loading following a LOOP when no postulated accident occurs.
	EDG loading	IN 92-53, IN 91-13, LERs 50-247/89-06, 286/89-10	Consider worst-case conditions (frequency, voltage, electrical power factor, and the environment) when testing EDG load shedding and loading; verify EDG loading for all ECCS modes
Inadequate acceptance criteria		LER 50-325/96-006	Head losses necessary to account for the difference in the surveillance flow path versus the normal reactor vessel injection flow path were not adequately included in establishing the acceptance criteria
Inadequate postmodification testing		IN 96-15	Numerous modifications were made to components that operate from both main control room and remote shutdown panel. Post-modification testing of the components had not included operation from the remote shutdown panel, nor were any periodic surveillance tests performed on the remote shutdown panel.
Inadequate testing frequency		IN 93-13, LERs 50-455/90-07, 483/91-03	Consider increasing the frequency of SI system total flow testing and branch line flow testing to balance individual injection line flow rates

PART 25
NONMANDATORY APPENDIX B
Guidance for Testing Certain System Characteristics

B-1 PURPOSE

This Appendix provides additional guidance on identifying the following system characteristics and verifying that their acceptance criteria are met:

(a) safety injection accumulator discharge flow path resistance

(b) ECCS pump total dynamic head (*TDH*) versus flow

(c) ECCS subsystem discharge flow path overall resistance

(d) ECCS subsystem balanced branch line resistance

B-2 VERIFYING SAFETY INJECTION SYSTEM ACCUMULATOR DISCHARGE FLOW PATH RESISTANCE IN PWRs

Verification of this system characteristic involves filling each accumulator to a sufficient level and pressure to accomplish the required testing and individually discharging each into the reactor coolant system (RCS). Use the discharge flow rate and differential pressure between the accumulator and the RCS to calculate discharge flow path resistance. The discharge flow rate may be calculated from the change in accumulator water level versus time measurements. Collect the data once the line isolation valve is fully open.

The testing should be performed with sufficient accumulator charge and inventory to allow opening of all in-line check valves to their design basis flow position for sufficient duration to collect the necessary data.

B-3 TYPICAL ECCS SUBSYSTEM

A typical PWR ECCS subsystem is shown in Fig. B-1(a) to support the discussions in paras. B-4 through B-7. The subsystem is shown with the pumps aligned to distribute to the RCS cold legs by means of the safety injection branch lines. The isolated paths may represent additional ECCS paths (e.g., hot leg injection) or normal operating paths (e.g., reactor coolant pump seal injection or chemical volume and control system charging), which may be isolated during the test. In addition, the subsystem may have pump minimum recirculation flow paths that are not shown.

A special two-pump BWR ECCS injection path to the Reactor Pressure Vessel (RPV) is shown in Fig. B-1(b) to support the discussions in paras. B-4 and B-5. The isolated paths may represent additional operating paths (e.g., suppression pool cooling, containment spray, or decay heat removal), which may be isolated during the test. In addition, the pumps may have pump minimum flow paths that are not shown.

B-4 IDENTIFYING AND VERIFYING PUMP *TDH* VERSUS FLOW ACCEPTANCE CRITERIA

The safety analysis [performed in accordance with para. 6(a) or equivalent] for a specific initiating event is based on ECCS delivered flow as a function of RCS pressure for boundary conditions specific to the event. Some analyses use minimum ECCS flow (e.g., small break LOCA) and some use minimum and maximum ECCS flow (e.g., inadvertent ECCS actuation). The minimum and maximum ECCS flows used in the safety analysis establish limits on the ECCS pump minimum required and maximum allowable performance. These limits are the acceptance criteria for the system characteristic, pump *TDH* versus flow.

For PWRs, distribute the *TDH* versus flow data points as evenly as possible between minimum and expected flow rates. For critical portions of the pump curve, take additional data points as needed. For BWRs, obtain the *TDH* versus flow data of minimum, maximum achievable, and design basis flow rates; this data may be obtained using a test return line in lieu of injection to the RPV. Acceptance criteria developed in accordance with para. 7 will be minimum and maximum *TDH* versus flow. Figure B-2 graphically illustrates correction of measured data for estimated instrument accuracy as described in para. 7. Figure B-3 illustrates the same data points with analysis limits corrected for instrument accuracy as described in para. 7. Both figures illustrate acceptable test results.

B-5 VERIFYING DISCHARGE FLOW PATH RESISTANCE

The ECCS flow rates used in the safety analysis are a function of the ECCS pump performance, system resistances, and system boundary conditions. The minimum and maximum flow rates used in the analysis will place limits on the safety injection discharge flow path

Fig. B-1(a) Typical PWR ECCS Subsystem

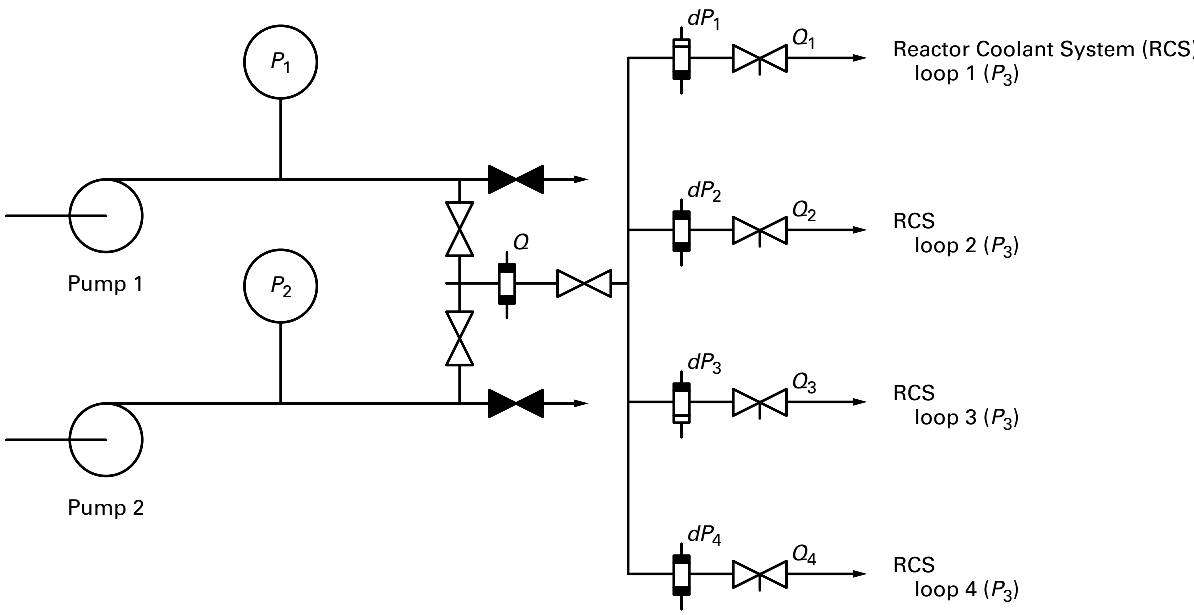
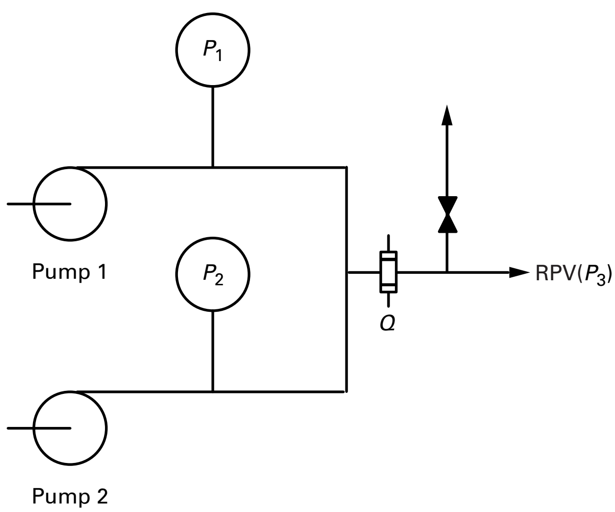


Fig. B-1(b) Typical BWR ECCS Subsystem



resistance and branch line balance. In addition, minimum limits on system resistance may be necessary to prevent excessive pump runout (i.e., for PWRs, during long-term core cooling operation when pumps may be operated in series). These minimum and maximum limits are the acceptance criteria for the system characteristic of safety injection discharge flow path resistance.

Consider paths that may divert flow from the ECCS injection path when verifying system resistance. Examples of such paths are pump minimum recirculation paths, reactor coolant pump seal injection path, and supply paths to other pumps during series pump operation. Typically, establish minimum resistance limits for these paths to ensure minimum ECCS flow and to prevent ECCS pump runout. Establish maximum limits to ensure the paths perform their design function. These minimum and maximum limits form acceptance criteria for the individual flow path resistances. Test individual flow path resistances in addition to the safety injection flow path resistance to verify the characteristic of system discharge flow path resistance.

Verification of this system characteristic, for the subsystem pictured in Figs. B-1(a) and B-1(b), involves operating either pump aligned to the RCS or RPV while recording pump discharge pressure, P_1 or P_2, as appropriate, total pump flow, Q, and calculating RCS or RPV back pressure, P_3, since the RCS or RPV will typically be depressurized for this test. Discharge flow path overall resistance, K_{measured}, is then calculated as follows:

$$K_{\text{measured}} = \frac{P_1 - P_3}{Q^2_{\text{pump 1}}} \text{ or } \frac{P_2 - P_3}{Q^2_{\text{pump 2}}}$$

where

K = discharge flow path resistance
P_1 and P_2 = pump discharge pressure
P_3 = RCS or RPV, back pressure
Q = total pump flow rate

This equation results from an application of Bernoulli's equation between the pump discharge and the RCS. It assumes that changes in elevation and velocity heads are negligible compared to changes in static pressure head. This assumption is often appropriate to high head pump systems, but should be verified for the specific application. The changes in static pressure head

Fig. B-2 Verifying Pump *TDH* Versus Flow:
Correction of Measured Data for Instrument Accuracy

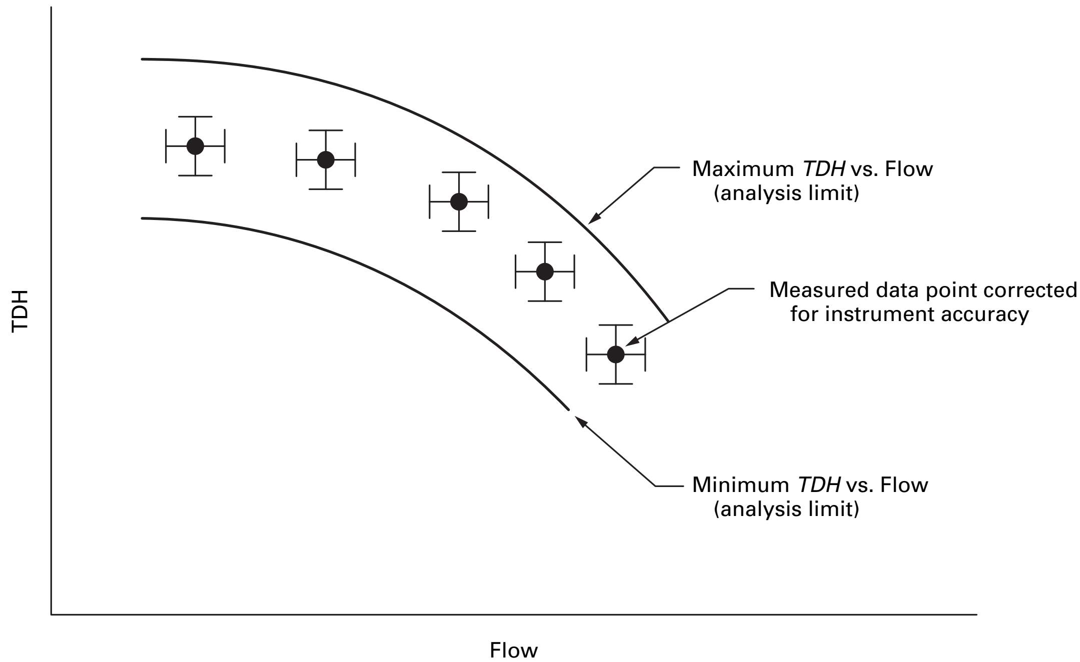
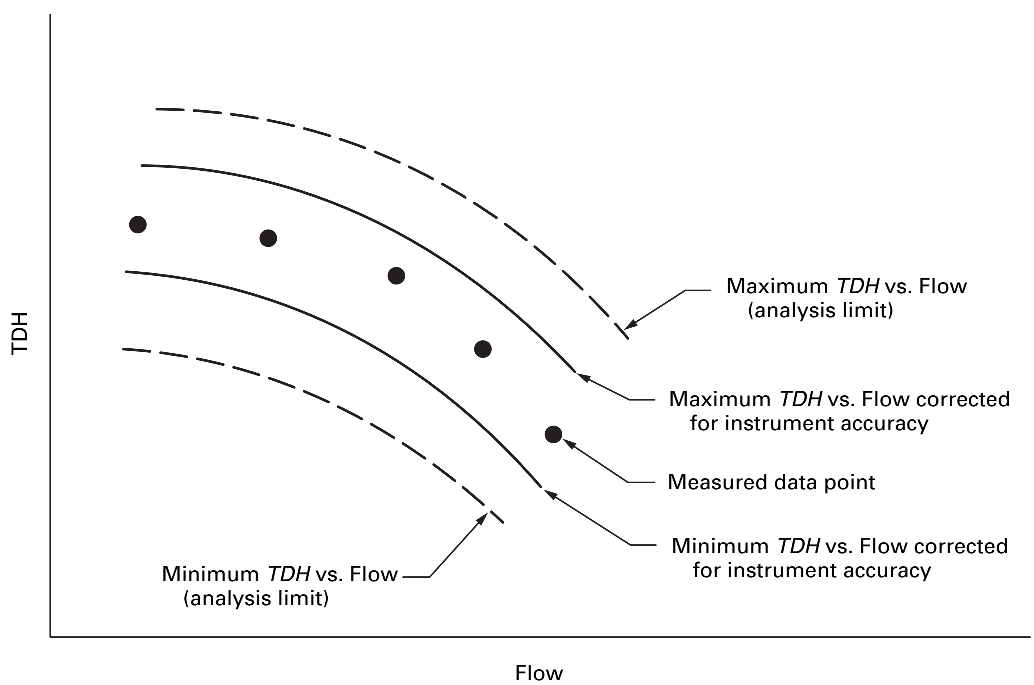


Fig. B-3 Verifying Pump *TDH* Versus Flow:
Correction of Analysis Limits for Instrument Accuracy



are attributed to unrecoverable friction and form losses. These are expressed as the product of a hydraulic resistance and the square of the flow rate. In general, the hydraulic resistance is a function of Reynolds Number and depends on fluid velocity and temperature. If the fluid velocity and temperature at the test conditions vary significantly from design conditions, use of the equation may not be appropriate without modification.

Typically, the calculated $K_{measured}$ using either Pump 1 or Pump 2 will be about the same; therefore, only one pump need be tested. Review the noncommon flow path to confirm this. A stronger pump will have an operating point on a given system, which will result in higher pump discharge pressure and correspondingly higher flow such that $K_{measured}$ will be the same as in a test using the weaker pump.

Acceptance criteria developed in accordance with para. 7 will be K_{min} and K_{max}. Discharge flow path resistance can be plotted as a system curve using the relation:

$$H = KQ^2$$

where
H = head
K = discharge flow path resistance
Q = flow

Figure B-4 shows correction of measured data for estimated instrument accuracy while Fig. B-5 shows the same measured data with analysis limits corrected for instrument accuracy. Both figures illustrate acceptable test results. The final results for BWRs of implementing paras. B-4 and B-5 for an ECCS subsystem are graphically depicted in Fig. B-6. Note that this figure does not include any corrections for instrument accuracy.

B-6 VERIFYING BALANCED BRANCH LINE RESISTANCE IN PWRs

Meeting the ECCS performance requirement for flow delivered to the RCS versus back pressure assuming one faulted loop requires a minimum balance between subsystem branch lines. Although this balance is defined as a maximum difference in branch line hydraulic resistance, this resistance is typically difficult to measure on individual branch lines. Therefore, balance acceptance criteria will typically be expressed in terms of maximum allowable difference in either branch line flow rates or the related parameter of differential pressure, *dP*, across branch line flow elements.

For the ECCS subsystem, shown in Figs. B-1(a) and B-1(b), verifying the system characteristic of balanced branch line resistance requires operating either pump aligned to the RCS while recording flow element differential pressures dP_1, dP_2, dP_3, and dP_4. If the acceptance criterion is a maximum flow difference between branch lines, branch line flows are calculated using the relation:

$$Q_x = C\sqrt{dP_x}$$

where
C = flow coefficient
dP = flow element differential pressure
Q = calculated pipe flow rate

and the maximum difference is compared against the acceptance criterion. If the acceptance criterion is maximum allowable *dP* difference, the maximum test *dP* difference is compared against the acceptance criterion. In this instance, meeting the requirements of para. 7 for instrument accuracy would require *adding* a correction to measured data before comparing to criteria representing analysis limits or *subtracting* a correction from analysis limits before using them as criteria against measured data.

B-7 SYSTEM ADJUSTMENTS

If the testing described in para. B-5 or B-6 does not meet acceptance criteria, Part 25 allows the following two options:

(a) Reorifice and retest the system as required to meet the discharge flow path overall resistance and balanced branch line resistance acceptance criteria. In the subsystem depicted in Figs. B-1(a) and B-1(b), this is accomplished by adjusting the four throttle valves downstream of the flow elements.

(b) If possible, refine the analysis on which the acceptance criteria are based such that the measured data meet the revised acceptance criteria. The ECCS flow rates used in the safety analysis are a function of ECCS pump performance, system overall resistance, and branch line balance. The acceptable limits of one of these characteristics may be relaxed to gain margin by restricting the acceptable limits of the remaining characteristics.

The final result for PWRs of implementing paras. B-4 through B-7 for an ECCS subsystem is graphically depicted in Fig. B-6. Note that this figure does not include any corrections for instrument accuracy.

Fig. B-4 Verifying Discharge Piping Overall Resistance: Correction of Measured Data for Instrument Accuracy

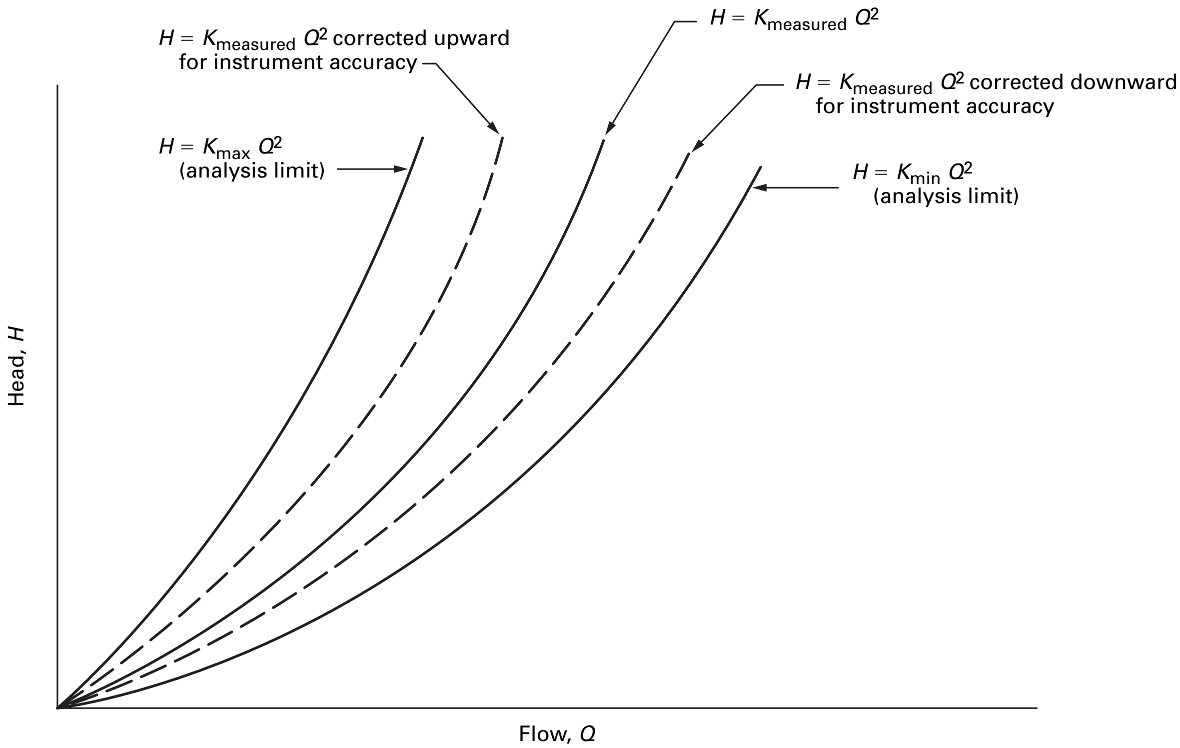


Fig. B-5 Verifying Discharge Piping Overall Resistance: Correction of Analysis Limits for Instrument Accuracy

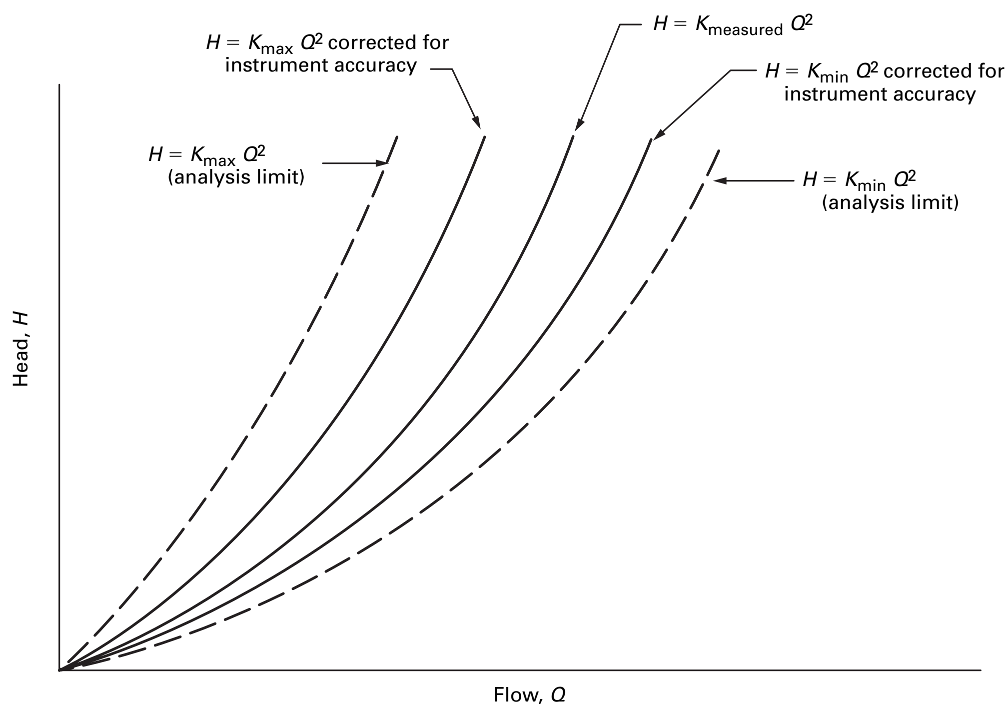
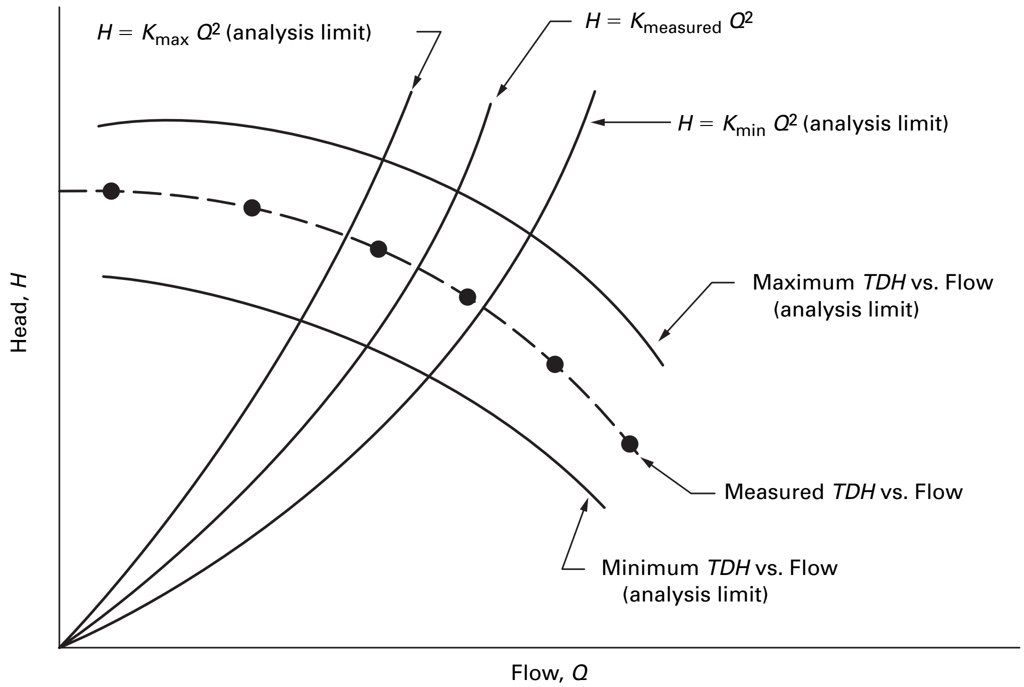


Fig. B-6 Measured Subsystem Operating Point and Range of Operating Points Allowed by Analysis Limits



PART 25
NONMANDATORY APPENDIX C
Measurement Accuracy of System Characteristics

C-1 BACKGROUND

Accuracy is defined as the closeness of agreement between the result of a measurement and the true value of the measured parameter. Accuracy statements for instruments are usually given as a percentage of either the upper range value (URV) or the true value. At a single measurement point, there are three sources of error. The average of many readings may be offset from the true value (bias error), the readings may be randomly scattered about the offset (precision error), and one reading may fall well outside the majority of readings (outlier error). It is the combination of the first two types of error that establishes the accuracy of an instrument.

If an instrument is to be used over a range of operation, it is possible to develop a calibration curve that accounts for the directional bias error. Then the calculation of accuracy reduces to the calculation of precision. However, this is not usually done for economic reasons. Instead, most instruments are type-tested to establish a reference accuracy envelope that incorporates precision, directional bias, and bias error range over a specified range of the measured variable. The limits of the envelope are specified as a percentage of the URV or reading. Accuracy envelopes are developed for reference conditions and apply within stated limits on ambient temperature, humidity, flow profile, and so on. If the instrument is installed in conditions outside the stated limits of the reference accuracy envelope, additional bias or precision errors may result. These sources of errors are referred to as influence quantities. In this Appendix it is assumed that accuracy envelopes exist for the instruments and that instruments are used within their reference range or adjusted for influence quantities.

System characteristics are variables or attributes that can be verfied by direct measurement or data reduction. The values of some system characteristics cannot be directly measured but can be verified by data reduction. Pump total dynamic head and system resistance are examples of characteristics that cannot be directly measured but can be calculated from other directly measured parameters, such as pressure and flow rate. Nonmandatory Appendix B discusses methods verifying that measured system flow (Q), pump total developed head (TDH), and system resistance (K) meet acceptance criteria, assuming that the accuracy of these variables (Q, TDH, or K) are known. The purpose of this Appendix is to provide a method of determining the accuracy of derived variables (Q, TDH, or K) based on the accuracies of the measured input variables.

C-2 NOMENCLATURE

The following symbols and units are used:

$(Acc)_Y$ = accuracy of variable Y
D = orifice bore diameter, in.
d = total differential operator
D_D = discharge pipe inside diameter, in.
D_P = pipe inside diameter, in.
D_S = suction pipe inside diameter, in.
g = acceleration of gravity, ft/sec^2
h_L = system head loss, ft
K = orifice flow coefficient
N_R = Reynolds Number
P = pressure, psig
P_B = system backpressure, psig
P_D = pump discharge pressure, psig
P_S = pump suction pressure, psig
Q = flow rate, gpm
T = temperature, °F
TDH = pump total developed head, ft
V_B = velocity at system exit,[1] ft/sec
V_D = velocity at pump discharge,[1] ft/sec
V_S = velocity at pump suction,[1] ft/sec
Z_B = elevation at system exit,[2] ft
Z_D = elevation at pump discharge,[2] ft
Z_S = elevation at pump suction,[2] ft
α = volume expansivity
β = diameter ratio
β_T = isothermal compressibility
ΔH_P = difference in pressure head, ft
ΔH_P = difference in pressure, psid
ΔH_V = difference in velocity head, ft
ΔH_Z = difference in elevation head, ft
μ = dynamic viscosity, lbm/ft-sec

[1] This designates the velocity in the fluid stream at the location of the pressure tap.

[2] This designates the elevation corresponding to the pressure measurement. This is usually the elevation of the pressure gage or transmitter. However, occasionally adjustment is made for the elevation head between the pressure tap and the pressure gage or transmitter in the calibration; in this case, the elevation of the pressure tap should be used.

ν = specific volume, ft^3/lbm
∂ = partial differential operator

C-3 SENSITIVITY COEFFICIENTS

Flow Measurement Engineering Handbook, 2nd edition (McGraw Hill, 1989), provides the following methodology for determining sensitivity coefficients. This methodology will be applied to various system parameters.

When an equation is used to calculate a quantity (Y) based on measured values of two or more variables (u, ν, w, ...), a mathematical entity called the total differential can be used to determine the individual effect of each variable on the final result. If the pertinent variables are independent, then the general functional relationship can be represented as

$$Y = f(u,\ \nu,\ w,\ ...)$$

The total differential is the sum of the partial differentials of the independent variables.

$$dY = \frac{\partial Y}{\partial u}du + \frac{\partial Y}{\partial \nu}d\nu + \frac{\partial Y}{\partial w}dw + ...$$

Dividing the equation for dY by Y yields an equation of the form

$$\frac{dY}{Y} = X_u\frac{\partial u}{u} + X_\nu\frac{\partial \nu}{\nu} + X_w\frac{\partial w}{w} + ...$$

where

$$X_u = \frac{u}{Y}\frac{\partial Y}{\partial u} = \frac{\dfrac{\partial Y}{Y}}{\dfrac{\partial u}{u}}$$

and du/u is the fractional change in u.

If the functional relation is of the form

$$Y = Cu^l\nu^m w^n\ ...$$

then $X_u = l$, $X_\nu = m$, and $X_w = n$.

If each instrument is corrected for the directional bias, or each instrument is operating within its accuracy envelope, the accuracies of the various measuring instruments may be combined by the square-root-sum-squares (SRSS) method to estimate the total measurement accuracy as follows:

$$(Acc)_Y = \pm\left\{[X_u(Acc)_u]^2 + [X_\nu(Acc)_\nu]^2 + [X_w(Acc)_w]^2 + ...\right\}^{1/2}$$

C-4 ACCURACY OF DIRECTLY MEASURED VARIABLES

In this Appendix, pressure, differential pressure, and temperature are treated as fundamental measured fluid properties or system parameters. It is assumed that the measurement accuracy of these parameters is known and can be expressed as a fraction of the measured parameter. This means that terms such as dP/P, $d(\Delta P)/\Delta P$, and dT/T are known. The accuracy of these variables will vary considerably based on such things as

(a) range of instrument
(b) method of processing signal
(c) method of displaying signal
(d) calibration frequency
(e) relation between calibrated (reference) conditions and test conditions (influence quantities)

C-5 ACCURACY OF DERIVED VARIABLES

Fluid properties, such as specific volume, are determined from a correlation (steam tables) that relates the derived property (ν) to fundamental measured properties such as pressure and temperature. The accuracy with which specific volume is known is made up of three parts as follows:

(a) the accuracy of the correlation between specific volume and pressure and temperature
(b) the accuracy with which fluid temperature is known
(c) the accuracy with which fluid pressure is known

The first accuracy is associated with the correlation and the latter accuracies are associated with the process variable measurements. We can write the overall accuracy as

$$(Acc)_\nu = (Acc)_{\text{Correlation}} + \left\{[X_T(Acc)_T]^2 + [X_P(Acc)_P]^2\right\}^{1/2}$$

where

$$X_T = \alpha T$$
$$X_P = -\beta_T P$$
$$\alpha = \frac{1}{\nu}\frac{\partial \nu}{\partial T}\ \text{(volume expansivity)}$$
$$\beta_T = -\frac{1}{\nu}\frac{\partial \nu}{\partial P}\ \text{(isothermal compressibility)}$$

C-6 ACCURACY OF FLOW RATE

This Appendix assumes that flow rate is measured with an orifice or other device that relates flow rate to a measured pressure change by an equation of the following form:

$$Q = SKD^2\sqrt{\nu\Delta P}$$

where S is a constant.

The overall accuracy can be expressed as

$$(Acc)_Q = \pm\begin{Bmatrix}[X_K(Acc)_K]^2 + [X_D(Acc)_D]^2\\ + [X_{\Delta P}(Acc)_{\Delta P}]^2 + [X_v(Acc)_\nu]^2\end{Bmatrix}^{1/2}$$

where $X_K = 1$, $X_D = 2$, $X_{\Delta P} = ½$, and $X_\nu = ½$.

The treatment of the above variables is addressed in paras. C-6.1 through C-6.4.

C-6.1 Flow Coefficient

The flow coefficient can be obtained from either a calibration curve for the specific flow element installation or a correlation for a reference installation of the general type of flow element (e.g., concentric square-edged orifice with flange taps). Deviations from the calibration or reference installation (e.g., proximity to elbow, concentricity requirements) or application (e.g., diameter ratio limits, pipe size limits, or Reynolds Number limits) require associated bias factors (influence quantities). To emphasize that the influence of installation or application must be considered, a separate bias term will be shown for the flow coefficient.

Since the flow coefficient is a function of the Reynolds Number and other parameters, the overall flow coefficient accuracy consists of a calibration or correlation accuracy plus an accuracy associated with the input parameters. Since the Reynolds Number depends on specific volume, the flow coefficient accuracy is dependent on the specific volume accuracy. However, in most applications, the effect of input variable (e.g., Reynolds Number and diameter ratio) accuracy on overall flow coefficient accuracy is negligible compared with the calibration or correlation accuracy. If this is not the case, the flow coefficient accuracy associated with the accuracy of the input variables must be taken into account.

C-6.2 Orifice Bore Diameter

The orifice bore diameter can be determined from as-built drawings or manufacturing specifications. Generally, the uncertainty in the as-built measurement is less than the specification tolerance; therefore, it is usually reasonable and conservative to use the specification tolerance for computing the bore diameter accuracy.

C-6.3 Orifice Differential Pressure

Orifice differential pressure is directly measured and the directional bias is applied if the instrument is not operating within its accuracy envelope. Therefore, the accuracy of the differential pressure measurement is known.

C-6.4 Specific Volume

This was treated in detail in para. C-5.

C-7 ACCURACY OF PUMP *TDH*

This pump-developed head can be calculated from measured variables by the following equation:

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

This can be written as

$$TDH = \Delta H_P + \Delta H_Z + \Delta H_V$$

where
ΔH_P = difference in pressure head, ft
ΔH_V = difference in velocity head, ft
ΔH_Z = difference in elevation head, ft

Assuming the accuracies of the suction and discharge pipe diameters are the same, the overall accuracy in pump *TDH* can be expressed as

$$(Acc)_{TDH} = \pm \left\{ \begin{array}{l} [X_\nu (Acc)_V]^2 + [X_{P_D}(Acc)_{P_D}]^2 \\ + [X_{P_S}(Acc)_{P_S}]^2 + [X_{\Delta Z}(Acc)_{\Delta Z}]^2 \\ + [X_Q(Acc)_Q]^2 + [X_{D_p}(Acc)_{D_p}]^2 \end{array} \right\}^{1/2}$$

where

$$X_\nu = \frac{\Delta H_P}{TDH}$$

$$X_{P_D} = \frac{\Delta H_P}{TDH}\left(\frac{P_D}{P_D - P_S}\right)$$

$$X_{P_S} = \frac{\Delta H_P}{TDH}\left(\frac{P_S}{P_D - P_S}\right)$$

$$X_{\Delta Z} = \frac{\Delta H_Z}{TDH}$$

$$X_Q = 2\,\frac{\Delta H_V}{TDH}$$

$$X_{D_p} = 4\,\frac{\Delta H_V}{TDH}$$

The following observations are made concerning this expression:

(a) The sensitivity coefficient for discharge pressure accuracy is much greater than the sensitivity coefficient for suction pressure accuracy. The discharge pressure weighting factor is usually slightly greater than unity and the suction pressure weighting factor approaches zero.

(b) The sensitivity coefficient for the accuracy of the elevation difference between pump discharge and suction pressure instrument locations is the ratio of the elevation difference to the pressure head. This value is usually extremely small compared to the weighting factors for pump suction and discharge pressure measurement.

(c) The accuracy of velocity head is broken into two terms as follows:

(1) the accuracy with which the flow rate is known

(2) the accuracy with which the suction and discharge pipe inside diameters are known

The weighting factor for both these terms is a multiple of the velocity head to pressure head ratio. The last term is usually very small relative to other terms. For most applications, the accuracy of the pump *TDH* measurement will be dictated by the accuracy of the discharge pressure measurement.

C-8 ACCURACY OF SYSTEM RESISTANCE

The safety injection system pump discharge head loss can be calculated from the measured system parameters by the following equation:

$$h_L = 144\nu(P_D - P_B) + (Z_D - Z_B) + \frac{V_D^2 - V_B^2}{2g}$$
$$h_L = \Delta H_P + \Delta H_Z + \Delta H_V$$

where
ΔH_P = difference in pressure head, ft
ΔH_V = difference in velocity head, ft
ΔH_Z = difference in elevation head, ft

The safety injection system resistance is defined as

$$K = \frac{h_L}{Q_{SI}^2}$$

Each of the above terms is independent and can be combined by the SRSS method to estimate the total measurement accuracy.

$$(Acc)_K = \pm \begin{Bmatrix} [X_\nu(Acc)_V]^2 + [X_{P_D}(Acc)_{P_D}]^2 \\ + [X_{P_B}(Acc)_{P_B}]^2 + [X_{\Delta Z}(Acc)_{\Delta Z}]^2 \\ + [X_Q(Acc)_Q]^2 + [X_{D_P}(Acc)_{D_P}]^2 \end{Bmatrix}^{1/2}$$

where

$$X_v = \frac{\Delta H_P}{h_L}$$

$$X_{P_D} = \frac{\Delta H_P}{h_L}\left(\frac{P_D}{P_D - P_B}\right)$$

$$X_{P_B} = \frac{\Delta H_P}{h_L}\left(\frac{P_B}{P_D - P_B}\right)$$

$$X_{\Delta Z} = \frac{\Delta H_Z}{h_L}$$

$$X_Q = 2\left(\frac{\Delta H_V}{h_L} - 1\right)$$

The specific volume at the test temperature and the pump discharge pressure is 0.016 ft^3/lbm (0.0009989 m^3/kg). The specific volume, along with the information in the above table, can be used to calculate the following parameters:

Table C-1 Sensitivity Coefficients for Pump *TDH*

Parameter	Sensitivity Coefficient	Value
Specific volume	X_ν	0.9956
Discharge pressure	X_{PD}	1.0251
Suction pressure	X_{PS}	0.0295
Elevation difference	$X_{\Delta Z}$	0.0018
Flow rate	X_Q	0.0052
Pipe diameter	X_D	0.0104

Parameter	Value, ft	Value, m
ΔH_P	1,633.5	497.9
ΔH_Z	3	0.91
ΔH_V	4.3	1.31
TDH	1,640.8	500.1

These parameters can be used to determine the sensitivity coefficients by means of the following formulas provided in para. C-7:

$$X_\nu = \frac{\Delta H_P}{TDH}$$

$$X_{P_D} = \frac{\Delta H_P}{TDH}\left(\frac{P_D}{P_D - P_S}\right)$$

$$X_{P_S} = \frac{\Delta H_P}{TDH}\left(\frac{P_S}{P_D - P_S}\right)$$

$$X_{\Delta Z} = \frac{\Delta H_Z}{TDH}$$

$$X_Q = 2\,\frac{\Delta H_V}{TDH}$$

$$X_{D_P} = 4\,\frac{\Delta H_V}{TDH}$$

The sensitivity coefficients calculated in this manner are summarized in Table C-1.

$$X_{D_P} = 4\,\frac{\Delta H_V}{h_L}$$

It is noted that system head loss is composed of both form losses and frictional losses. In general, each of these losses depends on Reynolds Number and other variables. Therefore, attention must be paid to differences between test conditions and operating conditions when developing and applying test criteria for system resistances.

C-9 EXAMPLE EVALUATION OF PUMP *TDH* ACCURACY

This paragraph provides a sample evaluation of the accuracy of the measurements of pump performance. The purpose is to illustrate use of the methodology provided in this Appendix.

C-9.1 Evaluation of Accuracy of Measurement of Pump Performance

Paragraph C-7 provides the following equation for determining the accuracy of pump *TDH*:

$$(Acc)_{TDH} = \pm \begin{Bmatrix} [X_\nu(Acc)_V]^2 + [X_{P_D}(Acc)_{P_D}]^2 \\ + [X_{P_S}(Acc)_{P_S}]^2 + [X_{\Delta Z}(Acc)_{\Delta Z}]^2 \\ + [X_Q(Acc)_Q]^2 + [X_{D_p}(Acc)_{D_p}]^2 \end{Bmatrix}^{1/2}$$

There are two aspects of evaluating the uncertainty in pump *TDH*.

(a) The sensitivity coefficients (X_I) must be determined for each parameter, which is used to calculate the *TDH*.

(b) The accuracy, $(Acc)_I$, of each individual parameter must be determined.

C-9.1.1 Evaluation of Pump *TDH* Sensitivity Coefficients. The following data was recorded during a test.

Parameter	Value (U.S. Customary Units)	Value (SI Units)
P_D	745 psia	5 136.6 kPa
P_S	36 psia	248.2 kPa
Q	1,580 gpm	0.09969 m^3/sec
Z_D	121 ft	36.88 m
Z_S	118 ft	35.97 m
D_S	7.981 in.	20.27 cm
D_D	5.761 in.	14.63 cm
T	70°F	21.1°C

It is seen that the two predominant factors in evaluating pump *TDH* are specific volume and discharge pressure. For the time being, in anticipation of the fact that $(Acc)_V \ll (Acc)_P$, let us ignore the effect of specific volume on overall accuracy. If we then assume the discharge pressure is known to an accuracy of 1% and the remaining parameters are known to an accuracy of 10%, the overall accuracy of the measurement is 1.1%. For this reason, conservative, but reasonable, accuracies for suction pressure, pressure gage elevation difference, flow rate, and pipe diameter can usually be used to determine the overall accuracy of the pump *TDH* measurement.

C-9.1.2 Evaluation of Pump *TDH* Component Accuracies

C-9.1.2.1 Specific Volume. Since the sensitivity coefficient for specific volume is approximately the same as that for discharge pressure, the accuracy of the specific volume will be examined in detail.

The total uncertainty in specific volume is made up of three parts as follows:

(a) the uncertainty resulting from the accuracy of the correlation as a function of pressure and temperature

(b) the uncertainty in fluid temperature

(c) the uncertainty in fluid pressure

The first uncertainty is associated with the correlation and the latter uncertainties are associated with the process variable measurements.

$$(Acc)_\nu = \pm (Acc)_{\text{Correlation}} \pm \left\{[X_T(Acc)_T]^2 + [X_p(Acc)_P]^2\right\}^{1/2}$$

where

$$X_T = \alpha T$$
$$X_P = -\beta_T P$$
$$\alpha = \frac{1}{\nu}\frac{\partial \nu}{\partial T} \text{ (volume expansivity)}$$
$$\beta_T = -\frac{1}{\nu}\frac{\partial \nu}{\partial P} \text{ (isothermal compressibility)}$$

The uncertainty in the specific volume correlation as a function of pressure and temperature was obtained from the fifth edition of the ASME Steam Tables. Over the range of 0 psia to 1,450 psia (0 bars to 100 bars) and 32°F to 212°F (0°C to 100°C), the uncertainty in the correlation is $(d_\nu/\nu) = 0.0004$ per Table 2 of Appendix 3 of that document. The values of specific volume are given as a function of pressure and temperature in the Steam Tables (within the ranges of 500 psia to 1,500 psia and 40°F to 120°F). These can be used to calculate the values of partial derivatives of specific volume with respect to pressure and temperature as follows:

$$\frac{\partial \nu}{\partial p} = -5 \times 10^{-8}\, \frac{\text{ft}^3/\text{lbm}}{\text{psi}} \left(-4.5 \times 10^{-10}\, \frac{\text{m}^3/\text{kg}}{\text{kPa}}\right)$$

$$\frac{\partial \nu}{\partial T} \le -2.375 \times 10^{-6}\, \frac{\text{ft}^3/\text{lbm}}{°\text{F}} \left(\le 2.7 \times 10^{-7}\, \frac{\text{m}^3/\text{kg}}{°\text{C}}\right)$$

A specific volume of 0.016 ft^3/lbm (0.0009989 m^3/kg) results in

$$\beta_T = -\frac{1}{\nu}\frac{\partial \nu}{\partial P} = 3.121 \times 10^{-6}\, \frac{\text{in.}^2}{\text{lb}} \left[4.5 \times 10^{-7}\ (\text{kPa})^{-1}\right]$$

$$\alpha = -\frac{1}{\nu}\frac{\partial \nu}{\partial T} = 1.483 \times 10^{-4}\ (°\text{F})^{-1} \left[2.7 \times 10^{-4}\ (°\text{C})^{-1}\right]$$

A temperature of 70°F (21.1°C) and a pressure of 745 psia (5,137 kPa) results in

$$X_T = \alpha T = 0.0104\ (0.0057)$$
$$X_P = -\beta_T P = -0.0023\ (-0.0023)$$

It is noted that the sensitivity coefficient for temperature changes upon conversion to metric units since the temperature in degrees Fahrenheit is not proportional to the temperature in degrees Centigrade.

The pressure gage used to measure the pump discharge pressure had a range of 0 psia to 3,000 psia (0 kPa to 21,000 kPa) and an accuracy of 1% of instrument range. The fluid temperature measurement had a range of 50°F to 200°F (10°C to 95°C) and an accuracy of 2% of instrument range.

$$(Acc)_P = \frac{dP}{P} = \frac{0.01\ (3{,}000\ \text{psi})}{745\ \text{psia}} = 0.04$$
$$\left(= \frac{0.01\ (21\ 000\ \text{kPa})}{5\ 137\ \text{kPa}} = 0.04 \right)$$

$$(Acc)_T = \frac{dT}{T} = \frac{0.02\ (150°\text{F})}{70°\text{F}} = 0.04$$
$$\left(= \frac{0.02\ (85°\text{C})}{21.1°\text{C}} = 0.08 \right)$$

$$(Acc)_\nu = \pm (Acc)_{\text{Correlation}} \pm \left\{[X_T(Acc)_T]^2 + [X_p(Acc)_P]^2\right\}^{1/2}$$

$$(Acc)_\nu = \pm 0.004 \pm \left\{ \begin{matrix} [0.0104(0.04)]^2 \\ + [0.0023(0.04)]^2 \end{matrix} \right\}^{1/2} = 0.0008$$

It is noted that the accuracy associated with the inputs decreases the overall accuracy by 100%. This is largely due to the fact that the correlation is very accurate.

C-9.1.2.2 Discharge Pressure. As determined above, the discharge pressure measurement had an accuracy of 4%.

C-9.1.2.3 Suction Pressure. The suction pressure instrument had a range of 0 psia to 100 psia (0 kPa to 700 kPa) had an accuracy of 1% of instrument span.

$$(Acc)_P = \frac{dP_S}{P_S} = \frac{0.01\ (100\ \text{psi})}{36\ \text{psia}} = 0.028$$
$$\left(= \frac{0.01\ (700\ \text{kPa})}{248\ \text{kPa}} = 0.028 \right)$$

C-9.1.2.4 Elevation Difference. The elevation difference measure is known to within 3 in. (7.6 cm). Therefore, the accuracy is

$$(Acc)_{\Delta Z} = (3\ \text{in.})(1\ \text{ft}/12\ \text{in.})/(3\ \text{ft}) = 0.08$$

C-9.1.2.5 Flow Rate. As previously mentioned, the impact of flow measurement accuracy on pump *TDH* measurement accuracy is very small. Therefore, a rough estimate of the accuracy is sufficient.

$$(Acc)_Q = \pm \left\{ \begin{matrix} [X_K(Acc)_K]^2 + [X_D(Acc)_D]^2 \\ + [X_{\Delta P}(Acc)_{\Delta P}]^2 + [X_\nu(Acc)_\nu]^2 \end{matrix} \right\}^{1/2}$$

where $X_K = 1$, $X_D = 2$, $X_{\Delta P} = \frac{1}{2}$, $X_\nu = \frac{1}{2}$.

$$(Acc)_K = (Bias)_{\text{Influence}} \pm (Acc)_{\text{Correlation}} \pm (Acc)_{\text{Inputs}}$$

The flow measurement accuracy is typically dominated by the accuracies with which the flow coefficient and differential pressure are known. The correlation accuracy for the flow coefficient is 1% and a bias of 0.5% is applied since the orifice is installed less than the required number of pipe lengths downstream of an elbow. The accuracy associated with uncertainties in Reynolds Number and diameter ratio are negligible. Therefore, the accuracy of the flow coefficient is 1.5%. The differential pressure is known within 2% of the measured value. The contributions due to uncertainties in bore diameter and specific volume are negligible. The overall accuracy in flow rate is estimated as

$$(Acc)_Q = \pm \left\{[(0.015)]^2 + [0.5(0.02)]^2\right\}^{1/2} = 0.018$$

Therefore, the flow measurement accuracy is dictated by the accuracy with which the flow coefficient is known.

C-9.1.2.6 Pipe Diameter. The pipe diameter is known to within 0.010 in. out of 5.761 in. Therefore,

$$(Acc)_{D_P} = \frac{dD_P}{D_P} = \frac{0.01\ \text{in.}}{5.761\ \text{in.}} = 0.0017$$

Table C-2 Pump TDH Overall Accuracy Calculation

Parameter	Sensitivity Coefficient, X_I	Accuracy, $(Acc)_I$	$[X_I(Acc)_I]^2$
ν	0.9956	0.008	6.344×10^{-7}
P_D	1.0251	0.04	1.681×10^{-3}
P_S	0.0295	0.028	6.823×10^{-7}
$Z_D - Z_S$	0.0018	0.08	2.074×10^{-8}
Q	0.0052	0.018	8.761×10^{-9}
D_P	0.014	0.0017	3.126×10^{-10}
$\Sigma[X_I\{Acc)_I]^2$	...	...	1.683×10^{-3}
Overall accuracy $\{\Sigma[X_I\{Acc)_I]^2\}^{1/2}$	...	...	0.0410

C-9.2 Results

$$(Acc)_{TDH} = \pm \left\{ \begin{matrix} [X_\nu(Acc)_V]^2 + [X_{P_D}(Acc)_{P_D}]^2 \\ + [X_{P_S}(Acc)_{P_S}]^2 + [X_{\Delta Z}(Acc)_{\Delta Z}]^2 \\ + [X_Q(Acc)_Q]^2 + [X_{D_p}(Acc)_{D_p}]^2 \end{matrix} \right\}^{1/2}$$

The sensitivity coefficients and accuracies are summarized in Table C-2.

It is seen that the accuracy of the pump *TDH* is dominated by the accuracy of the discharge pressure.

PART 26

PART 26
Determination of Reactor Coolant Temperature From Diverse Measurements

1 INTRODUCTION

1.1 Scope

This Part establishes the requirements to provide adequate justification for determining the reactor coolant temperature of pressurized water reactor (PWR) power plants by the use of diverse measurements.

This Part establishes measurement methods, parameters to be measured and evaluated, accuracy criteria, and records requirements so that reactor coolant temperature sensors can be calibrated in situ.

1.2 Applicability

(a) This Part provides a method for deriving reactor coolant system (RCS) temperatures from measured steam generator (SG) pressure. The RCS temperature is the sum of SG saturation temperature and the primary-to-secondary differential temperature. SG saturation temperature is directly related to RCS temperature through an overall heat transfer coefficient when positive, steady state, primary-to-secondary heat transfer is in progress. This heat transfer causes a primary-to-secondary temperature differential, which can be

(1) estimated by calculation

(2) forced to negligible values via specific plant conditions

(3) established by direct measurement

(b) This Part may be used to determine reactor coolant temperature by the use of SG pressures or temperatures.

(c) This Part shall only be used under saturated steam conditions. Plants that use superheated SGs shall ensure that they are operating in a saturated condition when this Part is used.

(d) This Part shall only be used under no-load conditions. It is best used under hot, no-load conditions where the ratio of steam pressure to temperature is the highest. At lower temperatures, there will be a corresponding decrease in accuracy.

(e) This Part has no acceptance criteria or corrective actions. It is used as a tool to determine RCS temperature. Plant procedures for calibrating reactor coolant temperature sensors may use the results of this Part for acceptance criteria requirements.

1.3 Basic Methodology

The methodology of this Part is to measure the SG pressure, convert the pressure to a saturation temperature, and then relate the steam saturation temperature to the isothermal temperature of the RCS. To determine the isothermal temperature of the RCS, the difference between the RCS temperature and the SG saturation temperature (ΔT_{ps}) shall be known.

The three basic methodologies for determining ΔT_{ps} are as follows:

(a) heat transfer calculation or analysis

(b) SG isolation

(c) direct measurement

2 DEFINITIONS

The following list of definitions is provided to ensure a uniform understanding of selected terms used in this Part.

constant: associated parameters maintained within the limits assumed in the uncertainty analysis.

isothermal condition: reactor coolant fluid in the loops and reactor vessel at essentially the same temperature and constant (except for deviations due to operating the loops with the reactor shut down).

no-load condition: steady state thermal load below the point of adding nuclear heat.

reactor coolant system (RCS): for this Part, the RCS consists of the major reactor coolant piping in the PWR, including the SG primary side and the reactor vessel.

SG: steam generator.

square root of the sum of the squares (SRSS): a method of combining uncertainties by using the SRSS of the random uncertainties.

steam tables (published by ASME): the 1997 Properties for Industrial Use tables based on the IAPWS-IF97 formulation are preferred, but any steam table approved by the Owner and/or nuclear steam supply vendor is acceptable.

ΔT_{ps}: temperature difference between the primary and secondary sides of the SG.

3 REFERENCES

The following is a list of publications referenced in and/or related to this Part.

ISA RP67.04, Part II, Methodologies for the Determination of Setpoints for Nuclear Safety Related Instrumentation

NRC Branch Technical Position HICB 13, Guidance on Cross-Calibration of Protection System Resistance Temperature Detectors (Revision 4), U.S. Nuclear Regulatory Commission, June 1997

Publisher: Superintendent of Documents, United States Government Printing Office, Washington, DC 20402

4 REQUIREMENTS

4.1 Plant Conditions

Use of this Part entails that minimum plant conditions be established to ensure that data taken are representative of the RCS temperature. These conditions shall be maintained throughout the period of measurements specified by this Part.

Plant parameters shall be established to maintain the RCS as close as possible to isothermal conditions. Parameters that can affect temperature differences between RCS loops and/or portions of RCS loops shall be identified and evaluated.

To obtain the maximum accuracy possible by the use of this Part, the RCS temperature shall be at or near maximum temperature for no-load condition. However, this Part may be used at lower temperatures provided it is taken into account in the uncertainty analysis.

(a) The RCS temperature shall be held constant.

(b) Sufficient reactor coolant pumps shall be in operation to establish isothermal conditions. It is not necessary for all reactor coolant pumps to be in operation.

(c) SG pressure shall be maintained within the assumptions made in the uncertainty analysis.

(d) Feedwater and SG blowdown flow, if operating, shall be held constant. Operation of feedwater and SG blowdown systems shall be evaluated because it influences the temperature difference across the SG tubes and may have an impact on isothermal conditions.

(e) Steady state isothermal conditions shall be maintained throughout the measurement.

(f) RCS shall be under a no-load condition.

4.2 Test Equipment

(a) Test equipment shall be calibrated in accordance with the Owner's test equipment program.

(b) Test equipment shall be designed for process and environmental conditions including instrumentation directly exposed to steam.

(c) Test equipment, including permanently installed instrumentation, shall be selected based on the ability to stay within the assumptions of the uncertainty analysis. See Appendix A for uncertainty guidance.

4.3 Uncertainty Methodologies

Uncertainties related to data collection techniques, current operating conditions, calculations, test equipment, and results shall be documented. As a minimum, the following parameters shall be considered for the uncertainty analysis to ensure accuracy of the results.

4.3.1 Operating Conditions

(a) RCS Temperature. If a plant is controlling to RCS temperature, the plant-specific RCS temperature control band shall be considered.

(b) Steam Pressure. If a plant is controlling to SG pressure, the plant-specific pressure control band, as it relates to RCS temperature, shall be considered.

(c) Steam Pressure Differences. For conditions where SGs are not isolated and are connected to a common header, steam pressures shall be averaged and uncertainties calculated accordingly. For SGs that are isolated or not connected to a common header, steam pressures shall be measured separately by SG and uncertainties calculated accordingly. SG pressure indications shall be combined in accordance with assumptions in the measurement uncertainty analysis. Dynamic head losses in the steam lines are negligible at no-load conditions.

(d) Decay Heat. If significant decay heat is present, the uncertainties associated with the decay heat shall be considered.

(e) Net Heat Addition Parameters. Uncertainty of parameters associated with RCS heat additions and losses shall be considered.

(f) SG Blowdown Flow. Uncertainty in the SG blowdown flow measurement shall be considered.

(g) Feedwater Flow Measurement. Uncertainty in the feedwater flow measurement shall be considered.

4.3.2 Test Equipment Uncertainties

(a) Uncertainties based on instrument range and accuracy shall be considered.

(b) Instrument uncertainties may be combined statistically using the SRSS of the random uncertainties and the sum of the bias uncertainties.

(c) Several independent instruments may be used to reduce the random errors associated with using the SRSS method.

Appendix A provides more detailed guidance on instrument uncertainties.

5 DEVELOP TEST PROCEDURES AND PERFORM TESTING

Procedures shall provide a method for deriving RCS temperatures from measured SG pressure. SG saturation temperature is directly related to RCS temperature through an overall heat transfer coefficient. The heat transfer causes a primary-to-secondary temperature differential. The RCS temperature is the sum of SG saturation temperature and the primary-to-secondary differential temperature (ΔT_{ps}).

5.1 Establish Primary-to-Secondary Side ΔT_{ps}

The test procedure shall use one or more of the following three methods to determine the difference between the RCS temperature and the SG saturation temperature:

(a) heat transfer calculation or analysis (see para. 5.1.1)

(b) SG isolation (see para. 5.1.2)

(c) direct measurement (see para. 5.1.3)

5.1.1 Establish ΔT_{ps} by Means of Heat Transfer Calculation or Analysis. The objective of this method is to establish primary-to-secondary temperature differential by using a heat transfer calculation or analysis. The RCS temperature can be directly related to SG saturation temperature when heat is being removed from the RCS by steaming. A single overall heat transfer coefficient can be derived by a calculation or measurement analysis. The coefficient shall be representative for the condition as defined in paras. 1.2(c) and 1.2(d) and take into account SG feedwater flow, blowdown, level, pressure, SG tube plugging/fouling, and primary system average temperature. Although the uncertainties in calculated heat transfer coefficients may be relatively large, the absolute differential temperature errors become small under no-load conditions.

Various industry computer programs for SG design are available for estimating the necessary heat transfer coefficient. In determining the appropriate coefficient, the steady state condition over which the calculated coefficient is valid shall be established because significant changes in heat transfer mode can take place under different operating conditions.

5.1.2 Establish ΔT_{ps} by SG Isolation. The objective of this method is to force ΔT_{ps} for one or more SGs as close to zero as practically possible, eliminating the need for a heat transfer calculation or analysis. Depending on the required accuracy, ΔT_{ps} can be assumed to be zero.

The methodology requires the isolation of one or more SGs and shutdown of the associated primary pump(s) of the isolated SG. Once the SG is isolated and the primary pump shut down, the (colder) primary coolant will reverse and the SG's steady state inventory will reach, after some time, a temperature very close to the primary coolant flowing through the SG tubes. This results in a very small ΔT_{ps} that can be expected to be negligible.

Equilibrium is reached when the heat loss of the isolated SG equals the heat loss of primary coolant to the SG inventory. A stable steam pressure of the isolated SG indicates equilibrium. Although the heat addition of the primary pump(s) is expected to be negligible, because the primary pump(s) is switched off for the isolated loop(s), there is no error introduced as a result of the rise in temperature of the primary pump hydraulic efficiency and (part of the) primary pump's head rise. Plant design configurations such as long or outside steam piping and weather conditions may have an impact on heat transfer in isolated SGs and shall be considered.

This method only provides RCS temperature values for the SG loops being isolated.

5.1.3 Establish ΔT_{ps} by Direct Measurement. This method determines ΔT_{ps} by direct measurement. The test to establish the primary-to-secondary differential temperature shall be performed once and shall employ at least one recently calibrated precision temperature instrumentation device to minimize uncertainties. The conditions at which the test is performed shall be repeated if the ΔT_{ps} is to be used for future reference. Changes in fouling and tube plugging can affect the accuracy of ΔT_{ps} for future use. Minimizing the heat load minimizes the error of ΔT_{ps}. Consider setting blowdown to zero during the test and for future calibrations using the ΔT_{ps} value.

5.2 Test Procedure Development

(a) Unless the direct measurement or the SG isolation methodology is used to determine SG ΔT_{ps}, heat transfer coefficients shall be calculated for use in test procedures. It is not required that the heat transfer coefficient calculations be part of the test procedure.

(b) Test procedures developed to perform this Part shall include references to the methodology of determining the temperature difference across the SG tubes, as described in para. 5.1.

(c) Test procedures shall consider uncertainty methodologies for test equipment, data collection techniques, current operating conditions, calculations, and results, as established in para. 4.3.

(d) Test procedure measurement requirements shall ensure that plant conditions remain within the operational limits assumed in calculation or measurement of heat transfer coefficients.

(e) It should be noted that, during the heating of the SG inventory, the steam pressure rises relatively easily as a result of the natural circulation within the SG. However, if the primary coolant temperature drops, the SG pressure response will be extremely slow due to the natural circulation in the SG inventory practically stopping. The procedure shall make provisions to invalidate the test if RCS temperature is not held steady (or on a slight incline).

5.3 Perform Test

(a) Initial Test Conditions. Establish initial plant conditions identified in para. 4.1.

(b) Steam Pressure. Steam pressure measurements shall be obtained consistent with the uncertainty analyses described in para. 4.3.

(c) Saturation Temperature. Determine saturation temperature at the surface of the SG from steam pressure measurement using ASME or other approved steam tables. Ensure steam head corrections are considered.

(d) Final RCS Temperature. Apply SG ΔT_{ps} determined in para. 5.1 to saturation temperature to obtain final RCS temperature.

(e) If using this Part for in situ calibration of reactor coolant temperature sensor resistance temperature detectors (RTDs), compare the final RCS temperature to RTD measurement results. Determine if results are consistent with plant uncertainty calculations.

6 DOCUMENTATION

The basis for establishing SG ΔT_{ps}, plant test conditions, and uncertainties shall be documented in accordance with the Owner's quality assurance program.

PART 26
NONMANDATORY APPENDIX A
Measurement Equipment Uncertainties

The measurement uncertainties are usually specified as a percentage of calibrated instrument range. The accuracy of the measurement can be improved by selecting instrumentation that is calibrated to a range close to the expected reading. Ensure that the instrumentation is not over-ranged during the test. Uncertainties may be combined statistically using the SRSS of the random uncertainties and the sum of the bias uncertainties. Refer to ISA RP67.04 for combining uncertainties. The methodology used for combining uncertainties shall provide a confidence level of at least 95% or 2σ.

Several independent instruments may be used to reduce the random errors associated with the instruments using the SRSS method. If numerous readings are taken due to data scatter, the mean should be calculated using at least 30 data points.

As a minimum, the following measurement equipment uncertainties shall be considered. These uncertainties may be included in the instrument uncertainty calculation or the instrument reading may be corrected to remove the uncertainty (i.e., static water head pressure and line pressure corrections are usually included in the calibration of plant instrumentation).

(a) Measurement and Test Equipment (M & TE) Accuracy. The accuracy of M & TE used to measure plant parameters or to calibrate permanent plant instrumentation.

(b) Reference Accuracy. Including conformity (linearity), hysteresis, deadband, and repeatability.

(c) Power Supply Voltage and Frequency Fluctuations. Electronic instrumentation is affected by variations in the power supply voltage and frequency. The manufacturer usually provides this effect.

(d) Temperature Effect. The difference in the ambient temperature between the last calibration and the temperature at the time of measurement can introduce a significant effect on the instrument.

(e) Static Pressure Effect. Changes in the output of instrumentation due to changes in the process or ambient pressure. Static pressure effect due to changes in ambient pressure can be caused by the use of a gage pressure instrument in a building that is not at atmospheric pressure. The instrument manufacturer usually provides process pressure uncertainty effect.

(f) Humidity Changes. The effect of changes in the ambient humidity on the instrument accuracy.

(g) Analog-to-Digital (A-D) Conversion, Digital-to-Analog (D-A) Conversion, and Digital Signal Processing. This introduces an uncertainty that varies with the conversion method and the number of bits used in the conversion.

(h) Instrument Drift. The change in the reading between the last calibration and the measurement.

(i) Readability. The readability of analog indications shall be considered in the uncertainty analysis. An analog indicator can be read to half of the smallest scale division.

GUIDES

PART 5

PART 5
Inservice Monitoring of Core Support Barrel Axial Preload in Pressurized Water Reactor Power Plants

1 PURPOSE AND SCOPE

1.1 Purpose

This Part outlines an inservice monitoring program for detecting significant loss of axial preload at the core support barrel's upper support flange in pressurized water reactors.

1.2 Scope

This Part provides guidance for inservice monitoring of core support barrel axial preload in PWR power plants and recommends monitoring methods, intervals, parameters to be measured and evaluated, acceptance criteria, and records requirements.

1.3 Application

This Part addresses the use of ex-core neutron detector signals to infer the condition of axial preload.

1.4 Definitions

(a) The following list of definitions is provided to ensure a uniform understanding of selected terms used in this Part:

axial preload: the axial clamping force at the core support barrel upper flange that prevents vertical or lateral motion of core support barrel at the location.

cantilever mode of vibration: the fundamental vibration mode of a simple beam with one end clamped and one end free.

core support barrel: the cylindrical structure located inside and concentric with the reactor pressure vessel that has the primary structural function of supporting the reactor core.

core support barrel frequency: the natural (resonant) frequency of the dominant beam mode response of the core support barrel vibration.

ex-core neutron detectors: neutron detectors located outside of the pressure vessel and at the same elevation as the core and used to monitor neutron flux as an indication of reactor power.

mechanical snubbers: dynamic restraint devices in which load is transmitted entirely through mechanical components.

neutron noise: fluctuations in the detected neutron signal from a reactor operating at steady state.

(b) The following terms pertaining to random data analysis are defined in ANSI S2.10-1971, Methods for Analysis and Presentation of Shock and Vibration Data:

(1) autopower spectral density function, APSD (also power spectral density)

(2) cross-power spectral density function, CPSD (also cross-spectral density)

(3) coherence function, COH

(4) root mean square, rms

(c) The following normalized spectral densities are referred to in this Part:

(1) normalized power structural density, NPSD

(2) normalized root mean square, nrms

(3) normalized cross-power spectral density, NCPSD

The normalized functions are defined in Nonmandatory Appendix B.

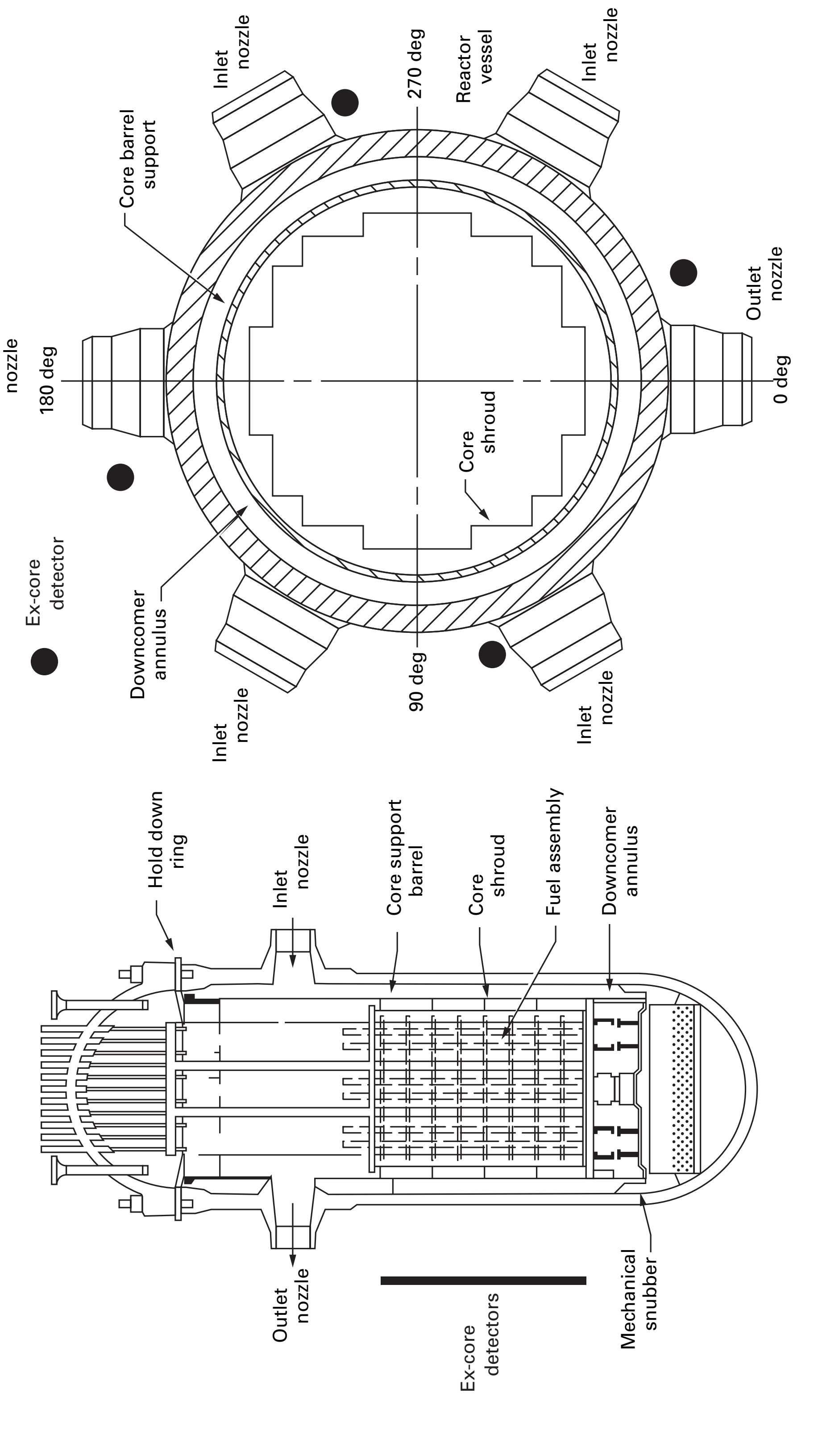
2 BACKGROUND

Figure 1 shows a cross-sectional view of a typical pressurized water reactor vessel and core support barrel. Flow-induced vibration of the core support barrel will change the thickness of the downcorner annulus (water gap) and this variation in thickness will result in corresponding variations in the neutron flux sensed by the detectors [see Fig. 1, sketch (b)].

The ex-core neutron flux signal is composed of a direct current component resulting from neutron flux produced by power operation of the reactor and a fluctuating signal or "noise" component. The fluctuating signal is associated with core reactivity changes and variations in neutron attenuation due to lateral core motion. This core motion is primarily the result of beam mode vibration of the core support barrel. Beam motion of the core support barrel is usually a very small neutron noise source, but it can be reliably identified through Fourier analysis and is typically characterized by 180 deg phase shift and high coherence between signals from ex-core detectors located on opposite sides of the core.

The natural frequencies and amplitudes of the core barrel cantilever mode of vibration are dependent on the effective axial preload at the core support barrel's upper support flange. Thus, monitoring the neutron noise signals measured by detectors located around the periphery of the reactor vessel (see Fig. 1) provides a

Fig. 1 Reactor Arrangement Showing Typical Ex-Core Detector Locations



(a) Reactor Arrangement

(b) Ex-core Detector Locations

method for detecting a significant loss of axial preload. The relationship between beam motion of the core support barrel and neutron noise signal can be derived from the shielding equation as described in Nonmandatory Appendix A.

3 PROGRAM DESCRIPTION

The program described in this Part is intended to detect significant loss of axial preload due to long-term changes (loss of axial restraint on the core barrel resulting from abnormal wear at the reactor vessel core barrel mating surface) or short-term changes (due to improper installation of the reactor internals).

The program has three phases: baseline, surveillance, and diagnostic.

Phase	Objective	Time
Baseline	To establish reference data for use in the surveillance and diagnostic phases of the program	Initial data acquisition or startup and as indicated below
Surveillance	To compare amplitude and frequency measurements with acceptable deviations from baseline values	Periodically during operation
Diagnostic	To investigate cause and significance of changes in signals that are not within the limits established in baseline phase	As surveillance phase indicates

The baseline phase establishes reference data for use in developing limits and trends for the surveillance phase and to support data interpretation in the diagnostic phase of the program. Baseline data should be obtained at the beginning, middle, and end of each of the first three fuel cycles of a new plant or during the first fuel cycle that the program is applied in a plant that is already operating. In addition, baseline data is required when significant changes are made to the core, reactor internals, or operating conditions.

The surveillance phase of the program covers routine monitoring during normal operation over the life of the plant. Data shall be taken at the start of each fuel cycle and every 90 effective full-power days (90 EFPD) or less throughout the cycle. If a change in the neutron noise signals that the frequency or amplitude of core barrel motion is not within predetermined limits, the diagnostic phase of the program shall be initiated.

The diagnostic phase of the program is used to identify the cause and significance of unexpected changes in the neutron noise signals identified in the surveillance phase. The phase will require additional analysis of current and previous data sets taken during baseline and surveillance phases to investigate the reasons for signal changes and to establish a future course of action.

A detailed description of each phase of the program is given in paras. 4 through 6. A summary of the program phases is shown in Table 1. Data reduction techniques are discussed in Nonmandatory Appendix B. Data acquisition information (instrumentation, signal conditioning, parameters, and plant conditions) is discussed in Nonmandatory Appendix C. Data evaluation (including use of acquired data, anomalies, and other experience) is presented in Nonmandatory Appendix D. Guidelines for evaluating baseline signal deviations (including data trends and user experience made available since the original release) are discussed in Nonmandatory Appendix E. Representative data are shown in Nonmandatory Appendices D and E.

4 BASELINE PHASE

4.1 Objective

The objective of this phase is to periodically establish a database for the plant to be used as reference information for the surveillance and diagnostic phases of the program.

4.2 Data Acquisition Periods

Data for use in establishing the reference database shall be collected at the beginning, middle, and end of each of the first three fuel cycles of a new plant or the initial program cycle of an operating plant and, at a minimum, after every core barrel removal, after every significant modification to the core, and after every significant modification of the reactor internals. Data should also be acquired prior to the removal of the core barrel and prior to anticipated significant modifications of the core or internals, as an aid in interpreting subsequent baseline data.

4.3 Data Acquisition and Reduction

The neutron noise time histories (analog or digital) from all functioning ex-core power range detectors (single section or summed signal from upper and lower sections) shall be recorded at each baseline phase data acquisition period. Analyses of these data shall include, as a minimum, determination of the following:

(a) normalized root mean square (nrms).

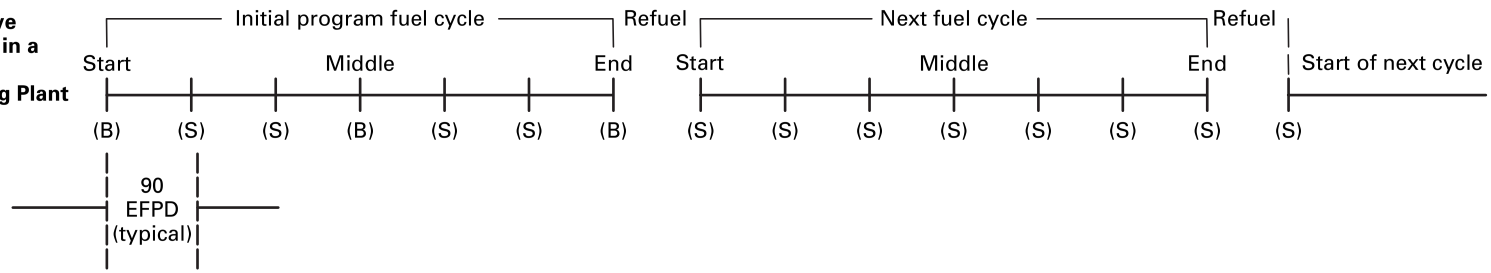
(b) normalized power spectral density (NPSD).

(c) normalized cross-power spectral density (NCPSD), phase, and coherence of all detector pairs at one deviation. If detector signals are available at more than one elevation, detector and detector pairs may be selected from more than one elevation, but signals used for a pair should be from the same elevation. As a minimum, two sets of cross-core (separated by 180 deg) detectors shall be monitored.

(d) wide- and narrow-band nrms values for frequency bands as defined in para. 4.4.

Table 1 Summary of Program Phases

Illustrative Program in a Typical Operating Plant



Program Phase	Frequency of Data	Data Acquisition	Data Reduction	Data Evaluation	Action
Baseline (B)	New plant: startup, middle, and end of first 3 fuel cyles to equilibrium Operating plant: startup, middle, and end of initial program cycle All: every significant change to core, internal or operating conditions	Time history and DC level of each detector and each cross-core detector pair	NPSD, NCPSD, COH, and phase for each detector and all cross-core and adjacent pairs of detectors, wide- and narrow-band rms	Establish characteristic amplitude and frequency of core barrel beam motion; select wide and narrow frequency bands and establish baseline nrms values within them; develop data "trends" throughout fuel cycles	If normal, enter surveillance phase; if abnormal, enter diagnostic phase
Surveillance (S)	Start and end of each fuel cycle and every 90 EFPD during the cycle	DC levels and data for frequency analysis of each detector and 2 pairs of cross-core detectors separated by approximately 90 deg	NCPSD for two cross-core pairs of detectors separated by approximately 90 deg wide- and narrow-band nrms, or narrow-band nrms and beam motion center frequencies	Comparison of amplitude and frequency results with limits	If normal, continue surveillance phase; if abnormal, enter diagnostic phase
Diagnostic (D)	As indicated by surveillance results	Same as baseline	Same as baseline	Complete evaluation of data taken during surveillance phase and comparison with baseline to note changes in spectral character and magnitude	Determine cause and significance of signal anomalies; define future plant operation and/or program plan

The data shall be analyzed over a minimum frequency band of 0.2 Hz to 20 Hz with a resolution that is consistent with amplitude and frequency changes to be deleted (see Nonmandatory Appendix C). During data acquisition, the plant shall be as close as possible to expected steady-state operating conditions.

4.4 Data Evaluation

The baseline data shall be used to establish two frequency ranges, a narrow and a wide band, and to establish the beam mode center frequency, for use in the surveillance and diagnostic phases. The narrow-band range shall encompass approximately ± 25% of the beam mode center frequency for the core support barrel. This band may be adjusted to remove the effects of adjacent peaks. This frequency band usually has a high coherence and 180 deg phase shifts between cross-core detectors (see Nonmandatory Appendix D). The center frequency of core barrel motion should be verified by the following:

(a) verified fluid-structural model calculations

(b) preoperational vibration measurement programs

(c) comparison with a similarly designed and constructed plant whose core barrel motion frequency has been verified by methods in para. 4.4(a) or 4.4(b)

A wide-band frequency range shall be established from 0.2 Hz to a minimum of 20 Hz that includes, as a minimum, responses in all anticipated support conditions.

Baseline NRMS values for both frequency ranges and beam mode center frequencies shall be determined based on both the normalized power spectral densities (NPSD) and the normalized cross-power spectral densities (NCPSD).

5 SURVEILLANCE PHASE

5.1 Objective

The objective of the surveillance phase of the program is to periodically confirm that the neutron noise nrms values are within predetermined limits. This shall be done by either periodic measurement and analysis or by a suitable continuous surveillance monitoring system. The program shall be conducted for each fuel cycle over the life of the plant.

5.2 Frequency of Data Acquisition

The data associated with the surveillance phase shall be acquired and evaluated at intervals of 90 effective full-power days or less, and at the beginning and end of each fuel cycle. Baseline data may be acquired in lieu of surveillance data.

5.3 Data Acquisition and Reduction

Data acquisition and evaluation shall be accomplished by either of the two means identified in para. 5.1. Values of nrms and center frequencies shall be determined from NCPSDs using pairs of cross-core (separated by 180 deg) detectors. The detector pairs shall be separated by approximately 90 deg. In addition, data shall be acquired to permit preparation of coherence and phase for two cross-core detector pairs at a later time. Data shall be acquired to permit detection of a significant change in either the nrms values or the center frequency of the dominant beam mode response of the core support barrel vibration.

5.4 Data Evaluation

The narrow- and wide-band nrms values or narrow-band nrms and core support barrel beam mode vibration frequency(ies) shall be compared to corresponding values established during the baseline phase. The acceptable range of nrms values and beam mode center frequency(ies) shall be established by the plant Owner. Allowances may be made for gradual changes in nrms and beam mode center frequency values due to nonmechanical phenomena. If the nrms values or resonance frequency fall outside the acceptable range, the program shall progress to the diagnostic phase.

Guidelines for establishing criteria for entering the diagnostic phase of the program are given in Nonmandatory Appendix D.

6 DIAGNOSTIC PHASE

6.1 Objective

The objective of this phase of the program is to establish whether or not deviations from the baseline data detected in the surveillance program are due to changes in core barrel motion, which may be indicative of loss of axial restraint, and to establish further actions to be undertaken.

6.2 Data Acquisition Periods

Initial results of this phase of the program shall indicate whether or not the minimum frequency of acquiring surveillance phase data should be increased or whether or not both the frequency and type of data acquisition and analysis should be changed from that recommended for the surveillance part of the program.

6.3 Data Acquisition, Reduction, and Evaluation

The NPSDs, NCPSDs, coherences, and phases shall be contrasted to data recorded during the baseline and surveillance program phases. Results of these and other observations (see Nonmandatory Appendix D) shall be used to indicate whether further data acquisition or analyses shall be undertaken. The trend of deviations shall be established and used to define the frequency of further data acquisition that will provide adequate indication of changes that are of sufficient magnitude to warrant further action.

If the results of data evaluation indicate possible anomalous behavior, other than sources of diagnostic information may be used (see Nonmandatory Appendix D).

PART 5
NONMANDATORY APPENDIX A
Theoretical Basis

Using the simplifying assumption that changes in the neutron flux from core barrel motion are due only to shielding (attenuation) effects, the relationship between beam motion of the core support barrel and the neutron nose signal can be derived from the following shielding equation.[1]

$$\phi_d = \phi_o e^{-X\Sigma_r}$$

where

X = the shield thickness
ϕ_d = the instantaneous detected neutron flux
ϕ_o = the core source flux
Σ_r = the effective neutron removal cross-section

The detected neutron flux after a small motion ΔX relative to the pressure vessel is then

$$\phi'_d = \phi_o e^{-(X+\Delta X)\Sigma_r}$$

The corresponding fractional change in detected neutrons is

$$\frac{\phi_d - \phi'_d}{\phi_{id}} = 1 - (e^{-\Delta X\Sigma_r})$$

which for small $\Delta X\Sigma$ becomes

$$\begin{aligned}\frac{\phi_d - \phi'_d}{\phi_d} &= 1 - (1 - \Delta X\Sigma_r)\\ &= \Delta X\Sigma_r\end{aligned}$$

so that

$$\Delta X = \frac{1}{\Sigma_r}\frac{\phi_d - \phi'_d}{\phi_d}$$

For dynamic measurements, $(\phi_d - \phi'_d)$ is the instantaneous neutron noise voltage such that

$$\Delta X(t) = \frac{1}{\Sigma_r}\left[\frac{\Delta\phi(t)}{\phi_d}\right]$$

or

$$\Delta X(\omega) = \frac{1}{\Sigma_r}\left[\frac{\Delta\phi(\omega)}{\phi_d}\right]$$

The rms motion in a particular frequency band is

$$\Delta X_{\text{rms}} = \frac{1}{\Sigma_r}\frac{\left\{\int_{f_2}^{f_1}[\Delta\phi(\omega)]^2 d\omega\right\}^{1/2}}{\phi_d}$$

or

$$\Delta X_{\text{rms}} = \frac{1}{\Sigma_r}\left[\int_{f_2}^{f_1}\text{NPSD}(\omega)d\omega\right]^{1/2}$$

where

$NPSD(\omega)$ = the normalized neutron noise power spectral density (PSD) obtained by dividing the noise voltage PSD by the square of the mean value voltage from the detector $(\overline{\phi}_d)$
= $\text{PSD}(\omega)/\overline{\phi}_d^{\,2}$

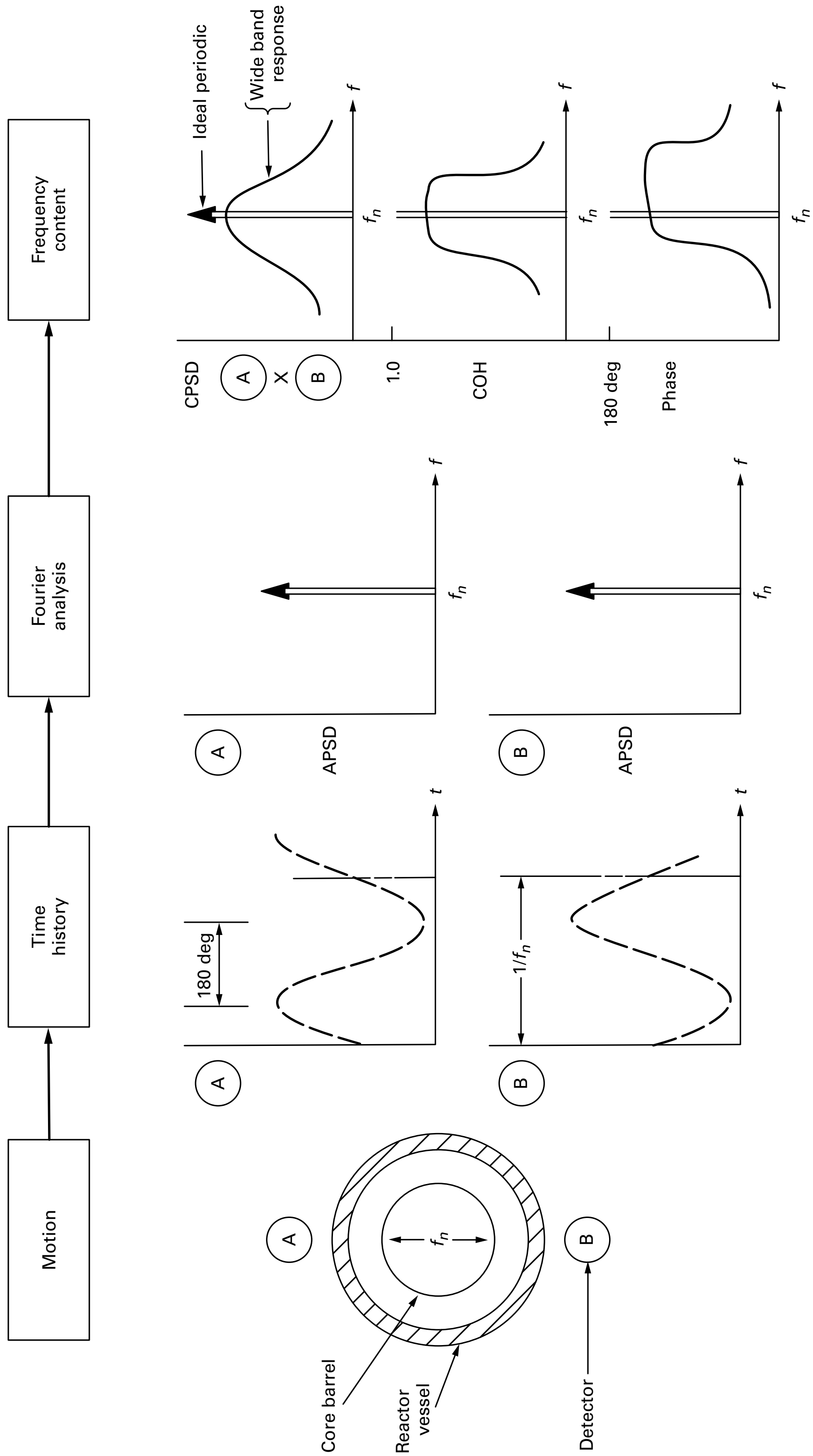
Power spectral density, so normalized, is used throughout this Part. Conversion of this normalized value (units of fraction of noise) to amplitude of motion (units of mils) is discussed in Nonmandatory Appendix F. For lateral motion at the beam frequency, signals from cross-core detectors will be 180 deg out-of-phase (maximum one side, minimum opposite side).[2,3] Furthermore, these cross-core signals will have a high value of coherence generally between 0.5 and 1.0. Example signals for one cycle of motion are shown in Fig. A-1.

[1] J. A. Thie, "Quantitative Diagnostic Techniques Using Ex-Core Neutron Detectors," *Proceedings of the Symposium on Power Plant Dynamics, Control, and Testing* (Knoxville: University of Tennessee, 1973).

[2] J. A. Thie, "Theoretical Considerations and Their Application to Experimental Data in the Determination of Reactor Internals' Motion From Stochastic Signals," *Annals of Nuclear Energy* 2 (1975): 253.

[3] J. C. Robinson et al., "Monitoring of Core Support Barrel Motion in PWRs Using Ex-Core Detectors," *Progress in Nuclear Energy* 1 (1977): 369–378.

Fig. A-1 Idealized Analysis for Core Barrel Motion



More complete reviews of the relationship between excore detector signals and internals motion appear elsewhere.[4, 5]

[4] J. A. Thie, "Core Motion Monitoring," *Nuclear Technology* 45 (1979): 5.

[5] F. J. Sweeney and J. A. Renier, "Sensitivity of Detecting In-Core Vibrations and Boiling in Pressurized Water Reactors Using Ex-Core Neutron Detectors," Report ORNL/TM-8549 (Oak Ridge, Tennessee: Oak Ridge National Laboratory, 1984).

An overview of experience with excore monitoring of core barrel motion also appears elsewhere.[1, 6, 7]

[6] R. C. Kryter et al., "U.S. Experience With Inservice Monitoring of Core Barrel Motion in PWRs Using Ex-Core Neutron Detectors," *Proceedings of the International Conference on Vibration in Nuclear Plants* (London: British Nuclear Society, 1979): 729–748.

[7] D. N. Fry, J. March-Leuba, and F. J. Sweeney, "Use of Neutron Noise for Diagnosis of In-Vessel Anomalies in Light Water Reactors," Report ORNL/TM-8774 (Oak Ridge, Tennessee: Oak Ridge National Laboratory, 1984).

PART 5
NONMANDATORY APPENDIX B
Data Reduction Techniques

The following is a brief description of various parameters used in baseline, surveillance, and diagnostic programs to identify core barrel motion.[1] It should be noted that all parameters are normalized to the operating power level (the dc value of the excore detector signal).

B-1 NORMALIZED POWER SPECTRAL DENSITY (NPSD)

The normalized power spectral density (the auto-power spectral density or APSD divided by the dc signal level squared) is a decomposition of a stochastic function into functions of frequency [Fig. B-1, sketch (a)]. It provides a measure of the signal power (mean square level) within discrete frequency bands over specified frequency ranges. The sampling rate, sampling time, and sample size are governed by the frequency range and band width.

B-2 NORMALIZED ROOT MEAN SQUARE OF THE SIGNAL

The normalized root-mean-square (nrms) value of the neutron noise signal is a measure of the amplitude of core barrel motion. However, it may include systematic variations due to changing plant conditions, e.g., burnup, changes in β_{EFF} (delayed neutron fraction) reactivity coefficients, and the like, which can contribute to a change in the nrms level. Since the nrms level is normalized to the dc level, it is dimensionless.

The rms value of the band f_1 to f_2 can be computed from NPSD as follows:

$$(\text{nrms})^2 = \int_{f_1}^{f_2} \text{NPSD}\, df$$

The NPSD can be used to calculate that portion of the total excore response related to core barrel motion. Observed over an extended period of time, it provides a sensitive measure of changes in motion.

[1] J. S. Bendat and A. G. Persol, *Random Data Analysis and Measurement Procedures* (New York: Wiley Interscience, 1971).

The NPSD is expressed as signal voltage squared per dc signal voltage squared per unit of frequency (1/Hz).

B-3 NORMALIZED CROSS-POWER SPECTRAL DENSITY (NCPSD), COHERENCE (COH), AND PHASE (ϕ)

B-3.1 Normalized Cross-Power Spectral Density (NCPSD)

The NCPSD (the cross-power spectral density or CPSD divided by the product of the dc level of the two signals) provides a descriptor of commonality between two excore detectors [Fig. B-1, sketch (b)]. The ability of the NCPSD to discount noncoherent portions of the signal better defines the region of motion, and when used in conjunction with the coherence and phase, is preferred over the NPSD as a governing statistic for establishing core barrel motion.

The rms value over frequency band f_1 to f_2 can be computed as follows:

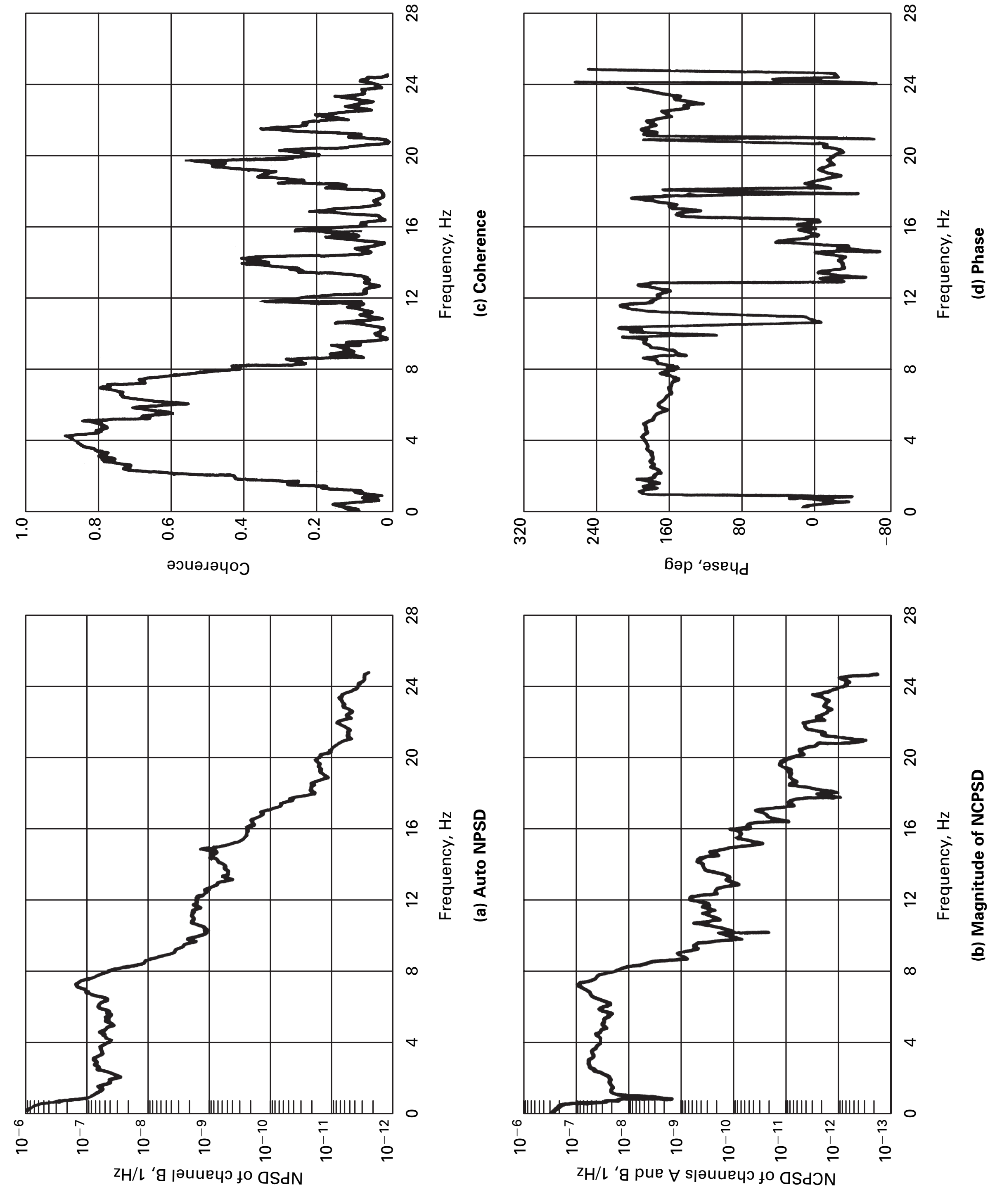
$$(\text{nrms})^2 = \int_{f_1}^{f_2} \text{NCPSD}\, df$$

The NCPSD is expressed as the product of signal voltages per product of dc voltages per unit of frequency (1/Hz).

B-3.2 Coherence (COH) and Phase (ϕ)

Although the NCPSD is a measure of the commonality between two variables, it is most convenient to represent the similar character in relative terms, relative to the individual signal NPSDs. This is done by calculating the coherence functions. The coherence is defined as the ratio of the square of the magnitude of the NPSD to the product of the individual NPSDs and is bounded between zero and one [Fig. B-1, sketch (c)]. If the coherence is one, the two signals are said to be fully coherent and, therefore, closely related. The corresponding phase data in this case are valid. Uncorrelated signals will have coherences approaching zero, rendering any phase data meaningless [Fig. B-1, sketch (d)]. Coherence is dimensionless, while phase is expressed in degrees.

Fig. B-1 Representative Spectra



PART 5
NONMANDATORY APPENDIX C
Data Acquisition and Reduction

C-1 INSTRUMENTATION

Neutron noise measurements can be made with prompt responding neutron detectors such as those used for plant monitoring and control. The output of these detectors is commonly conditioned by direct coupled current-to-voltage conversion equipment and linear amplifiers. Neutron noise measurements remove the mean value of the signal and provide additional amplification of the dynamic component. The amplified neutron noise signals can be analyzed online and in real time or recorded on magnetic tape for later processing.

C-2 SIGNAL CONDITIONING

Neutron noise signals are typically very small magnitude compared to the mean value neutron flux and to possible electrical noise interference. Precautions should be used to minimize electrical noise pickup and to obtain adequate dynamic range in the frequency band of interest.

(a) The noise floor of the signal conditioning equipment should be at least 10 dB below the expected neutron noise signals in the frequency band of interest.

(b) Filters and input common mode rejection should be used to limit electrical interference and signals outside the frequency band of interest to within the dynamic range of the signal-conditioning equipment.

(c) Signal-conditioning gains should be set so that noise introduced by normal plant operations (such as small control rod motion) do not overload the signal conditioning equipment during data acquisition.

(d) Neutron noise signals derived from plant control instrumentation should be examined for evidence of noise induced by plant-monitoring instrumentation.

(e) Calibrations should be used to verify and correct for any variation in the frequency response of the instrumentation in the frequency band of interest.

C-3 DATA ACQUISITION PARAMETERS

Data recording introduces instrumentation, noise, and dynamic range limits on neutron noise signals. These limitations should be recognized and appropriate action taken to preserve adequate signal quality.

(a) The noise floor of the reproduced signal should be at least 10 dB below the expected neutron noise signals in the frequency band of interest.

(b) The signal conditioning and tape recorder input controls should be adjusted so that no signals exceed the maximum tape recorder input during data acquisition.

(c) The frequency response of the data recording system in the frequency band of interest should be verified.

(d) Digital recording systems should have sufficient amplitude resolution and input filters to reduce all conversion noise and aliased signal components to at least 10 dB below the expected neutron noise signal in the frequency band of interest.

C-4 PLANT CONDITIONS FOR DATA ACQUISITION

Plant operating parameters and changes in these parameters contribute to the interpretation of neutron noise signals. These should be measured and noted at the beginning and end of each neutron noise data acquisition.

(a) Plant parameter changes are a potential source of neutron noise. The measurement of vibration-related neutron noise should be done as close to steady-state plant conditions as possible to minimize other noise sources.

(b) Primary plant parameters should be logged as part of each neutron noise measurement. Parameters to be documented during data acquisition are listed in Table C-1.

C-5 DATA REDUCTION PARAMETERS

Data reduction can introduce noise and statistical uncertainty into neutron noise data. These potential sources should be recognized and controlled in data analysis.

(a) The noise floor of the data reduction methods should be at least 10 dB below the expected neutron noise signals in the frequency band of interest.

(b) Digital analysis systems should have sufficient resolution and input filtering to reduce all aliased signal components to at least 10 dB below the expected neutron noise signals in the frequency band of interest.

(c) All neutron noise measurements should be normalized as a fraction of the mean value of the detector signal.

Table C-1 Parameters to Be Documented During Data Acquisition

All Data	Plant name and unit number
	Date and time of data acquisition
	Plant conditions: power level, coolant flow rates, number of pumps operating, soluble boron concentration, fuel burnup (EFPD), fuel cycle number, system pressure, pressurizer level, control rod positions, and hot-leg and cold-leg temperatures for each loop
	Names of persons performing data acquisition
	Identification of signals
	Description of sensors including manufacturer, model number, serial number, and calibration data
	Description of signal conditioning equipment
	Gains of all devices between point of dc measurement and output of tape recorder or input to spectrum analyzer
	DC voltages at input to signal conditioning equipment
	Frequency cutoffs of filters
Tape Recordings	Description of tape recorder
	Tape number or identifier
	Recording format
	Starting and stopping tape footages
	Type of calibration signals recorded (should be recorded on each tape) and footages
	Tape speed
On-Line Analysis	Anti-aliasing filter settings
	Sampling rate
	Analysis window type
	Sample block size
	Frequency resolution
	Amount of data overlap
	Units of results
	Description of analyzer
	Gain of analyzer front end

(d) The frequency resolution of spectral density measurements should be at least 1% of the highest calculated frequency.

(e) The data record length for rms measurements and power spectral density measurements should provide a minimum of 100 ensemble averages without data overlap (see para. C-9).

(f) Relevant plant conditions and data reduction parameters should be indicated on reduced data. These include signal identification, reactor power, measurement data, analysis band width, and data length.

C-6 SIGNAL BUFFERING

It is preferable that the signals to be used for analysis be routed to a common panel. These signals should be fully buffered and isolated prior to common routing. The buffer circuitry shall not induce noise that would cause the noise floor to be greater than 10 dB below the expected neutron noise signal nor degrade the frequency band of interest. The isolation should be adequate to ensure that a short circuit at the connection point will not adversely affect plant operation.

C-7 DATA ASSURANCE

Methods and procedures should be used to ensure the quality of the neutron noise data.

(a) Plant signals should be verified and permanently attached by acceptable methods to the data acquisition/processing system. Otherwise connections must be verified at each measurement.

(b) Data acquisition should be performed according to a written procedure.

(c) Documentation of the data should include those parameters listed in Table C-1.

(d) Reduction of neutron noise data and display of analysis results should be performed in a consistent manner to facilitate comparison of the results over the lifetime of the plant.

C-8 DATA RETENTION

Baseline and surveillance data should be retained over the lifetime of the plant.

C-9 STATISTICAL UNCERTAINTIES IN NEUTRON NOISE DATA ANALYSIS

Definitions of noise descriptors (auto- or cross-correlation, PSD, CPSD, phase, and coherence) for random data involve limiting conditions that cannot be carried out in practice (i.e., analysis of an infinite number of time records or a time record of infinite time span). The inability to perform these operations under practical conditions leads to statistical errors in the analysis. These statistical errors are expressed as "random error" or residual uncertainty variance. In addition, some estimates may also be biased error.

Bias errors are usually associated with measurements of the amplitude of a resonance in the frequency spectrum. The bias error formulas for the PSD and CPSD magnitude are[1]

$$-1/3(\Delta f/B_r)^2 \tag{C-1}$$

where Δf is the analysis frequency resolution and B_r is the true (unbiased) half-power band width of a resonance. This formula does not hold for small numbers of ensemble averages and low coherences. The negative sign indicates that the bias errors result in estimated amplitudes that are lower than the true value. Bias errors can be reduced by using a finer frequency resolution in the analysis.

Bias errors associated with coherence (Υ^2) follow the following formula:

$$\hat{\Upsilon}^2 - \Upsilon^2 = \frac{1}{n_d}(1 - \Upsilon^2)^2 \tag{C-2}$$

where n_d is the number of ensemble averages, Υ^2 is the true coherence, and $\hat{\Upsilon}^2$ is the estimated coherence. This formulation indicates that if the true coherence is zero, the estimated coherence will be 1 for a 1 block average. Bias errors in the coherence are therefore reduced by increasing the number of ensemble averages.

Statistical errors in the PSD are given by

$$\sigma_{\mathrm{PSD}}/\widehat{\mathrm{PSD}} = 1/\sqrt{n_d} \tag{C-3}$$

and in the CPSD by

$$\sigma_{\mathrm{CPSD}}/\widehat{\mathrm{CPSD}} = 1/\sqrt{\Upsilon^2 n_d} \tag{C-4}$$

where σ is the standard deviation and $\widehat{\mathrm{PSD}}$ and $\widehat{\mathrm{CPSD}}$ are the mean values of the PSD or CPSD. For PSDs, this indicates that a single frequency estimate will have an uncertainty of ± 30% at the 99% confidence (3 standard deviation) level for 100 ensemble averages.

The statistical error for the coherence[2]

$$\frac{2\hat{\Upsilon}^2}{n_d}(1 - \hat{\Upsilon}^2)^2 \tag{C-5}$$

and for the CPSD [eq. (C-4)] depends on both the number of ensemble averages and the coherence. For low coherence, a large number of ensemble averages are needed to meet a given statistical error.

Experience in reactor noise analysis indicates that a minimum of 100 ensemble averages (without overlap) should be performed in estimating noise parameters and their statistics. Overlap processing can yield improved statistics for a fixed amount of data, but the minimum number of averages without overlap should be at least 100 (e.g., 100 nonoverlapping averages yields 200 averages with 50% overlap). Some analyzers invoke overlap processing automatically. In these cases, the amount of overlap should be determined and the number of averages adjusted upward to meet a desired statistical confidence level.

While these formulas serve as guides, the actual statistical behavior of data from a particular reactor should be verified by the noise analyst.

[1] J. S. Bendat and A. G. Persol, *Engineering Applications of Correlation and Spectral Analysis* (New York: John Wiley and Sons, 1980).

[2] G. C. Carter, C. H. Knapp, and A. H. Nutall, "Estimation of the Magnitude-Squared Coherence Function via Overlapped Fast Fourier Transform Process," *IEEE Transactions on Audio and Electroacoustics* AU-21, 4 (1973).

PART 5
NONMANDATORY APPENDIX D
Data Evaluation

The various methods of reducing the data are of use only when subject to proper interpretation. This interpretation involves an evaluation of the data in conjunction with a knowledge of parameters (i.e., frequencies and mode shapes) related to core barrel motion. Equally important is an understanding of how a variety of neutronic effects can influence these data.

Experience has shown that the neutronic effects can be of the same magnitude as the vibration effects, which can lead to misinterpretations of the data. Careful examination of all data is required to separate out any effects that are not due to vibration from the neutron noise information.

The following is a listing of the information on core barrel motion and other types of noise effects that can be obtained from an evaluation of the spectral analysis data during each phase of the program.

D-1 BASELINE

D-1.1 Normalized Root Mean Square (nrms) Value

Baseline nrms values in both narrow- and wide-band frequency ranges or the narrow-band nrms value and center frequencies of core barrel beam motion may be used as a basis for comparing values obtained during the surveillance phase. Experience has shown that baseline nrms values can change from refueling to refueling and with changes in core parameters such as burnup and boron concentration. Thus, it may be desirable to re-evaluate baseline nrms values more frequently than the minimum schedule given in para. 4.2.

To establish the narrow-band rms baseline values, the center frequency of the core barrel beam mode must be identified as described in para. 4.3. A frequency range of approximately ± 25% of the center frequency is used to bound the narrow-band region as shown in Fig. D-1, sketch (a). Adjacent peaks may be omitted from the narrow-band region as shown in Fig. D-1, sketch (b). These methods may be used to define the narrow-band rms baseline value for either a continuous or periodic monitoring system.

Small changes may be found in the amplitude and/or center frequency, as shown in Fig. D-1, sketch (c), when baselines are taken. Significant changes, however, may indicate improper core barrel preload or other structural concerns that should be diagnosed.

The detector nrms signal levels will include components that are essentially uncorrelated between cross-core detectors and, therefore, are not due to lateral core support barrel motion. Furthermore, the nrms value in the low frequency band can increase with core burnup because of low frequency neutronic effects. These effects reduce the ability to distinguish core barrel motion changes from neutronic effects and require that the trend with burnup be considered in establishing values representing significant changes in the measured data.

Experience has shown that, in a number of reactors, a wide-band (0 Hz to 25 Hz) nrms value will increase linearly with operating time, measured in burnup and/or decreasing boron content. This is because neutronic effects related to thermal noise and/or fuel motion tend to increase with burnup and dominate the true beam motion portion of the signal. Thus, wide-band nrms values versus burnup should display a linear trend (Fig. D-2).[1] Significant changes from this trend would warrant a diagnostic phase investigation of the signal.

D-1.2 Normalized Power Spectral Density (NPSD)

The NPSD of an excore detector signal contains contributions due to actual motion and extraneous noise. As such, while its frequency spectra may be a good indicator of the frequency of motion, its amplitude will be higher than that due to the motion. Recognizing this limitation, the NPSD signal of each detector may be reviewed to note the following within the frequency range of core barrel motion:

(a) changes in amplitude

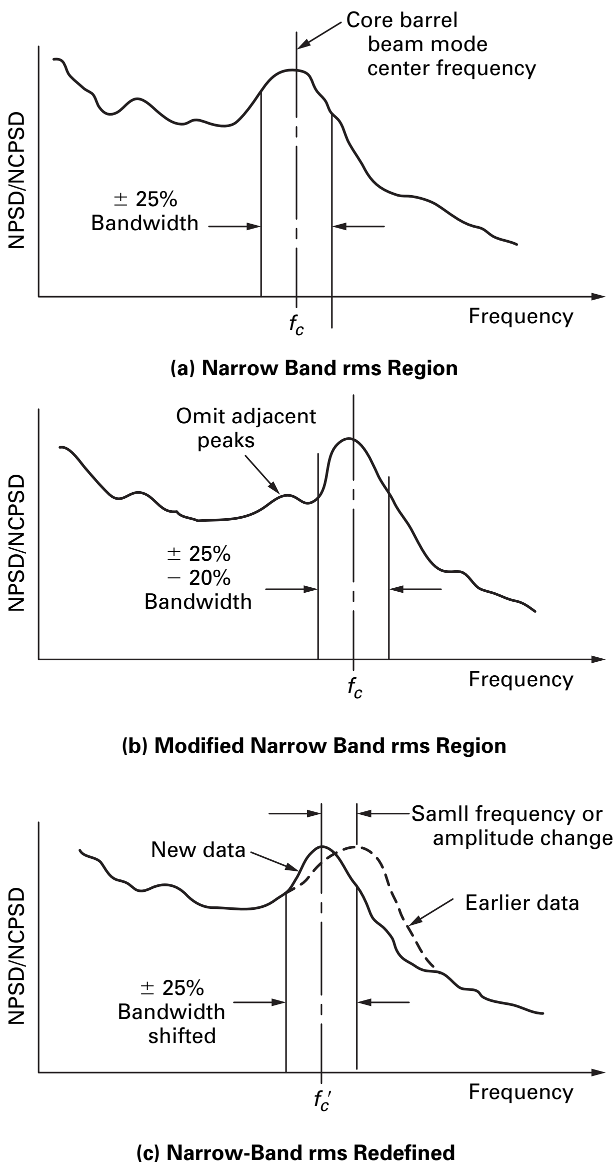
(b) shifts in frequency of the maximum amplitude

A significant change (increase or decrease) in amplitude or frequency, or both, may be indicative of changes in core barrel motion.

NPSDs will indicate the predominant core barrel frequency as a function of detector location. This may shift slightly from baseline to baseline due to changes in barrel position after refueling, broadening, or narrowing of the peak due to changing neutronic effects (e.g., fuel loading pattern, boron or burnup related).

[1] B. T. Lubin and J. H. Steelman, "Analysis of Changes With Operating Time in the Calvert Cliffs Unit 1 Neutron Noise Signals," *Progress in Nuclear Energy 1* (1977): 379–391.

Fig. D-1 Narrow-Band rms



D-1.3 Normalized Cross-Power Spectral Density (NCPSD), Coherence (COH), and Phase (ϕ)

The characteristic that the NCPSD does not include the effects of detector, or other noise sources, makes it, in conjunction with COH and ϕ, the most reliable indicator of core barrel motion. Investigations have shown that core barrel motion often follows a preferred (though random) path, resulting in the following COH and ϕ results:

Detector Pairs	COH	Phase (ϕ)
Cross-core	High (0.5 to 1.0)	Out-of-phase (~180 deg)
Adjacent, 90 deg apart	Low (~0.2)	Data not reliable

These relationships are based on core barrel beam mode vibration being the predominant contributor. Recent experience has shown that higher order fuel assembly vibrations and effects from fuel management changes can cause the phase and coherence relationships to be quite different even though no structural changes have occurred.[2] These data need to be carefully evaluated along with the NPSDs to verify core barrel motion.

Baseline NCPSDs are the best indication of frequency ranges for the subsequent surveillance phase rms measurements. The absence of a dominant peak within the expected core barrel frequency range, in combination with an order of magnitude greater in low frequency (0 Hz to 5 Hz) noise amplitude as compared with the expected amplitudes, should be taken as an indication of possible loss in core barrel axial restraint.

D-2 SURVEILLANCE PHASE

D-2.1 Root Mean Square

Root-mean-square values are to be calculated from the NCPSD functions in the manner shown by Nonmandatory Appendix B and compared with the values determined from the baseline measurements. Any unexpected deviation from known trends should instigate a diagnostic phase investigation.

D-2.2 Normalized Cross-Power Spectral Density (NCPSD)

NCPSD values shall be generated for two pairs of cross-core detectors during this phase and evaluated for magnitude and frequency changes in the core barrel motion frequency range. Any unexpected deviation from known trends should instigate a diagnostic phase investigation.

D-2.3 Coherence (COH) and Phase (ϕ)

Data shall be obtained so that COH and ϕ plots can be generated, if needed, for two pairs of diametrically opposed detectors. Review of these data and comparison with corresponding data obtained in the baseline phase may provide additional information on core barrel behavior.

D-3 DIAGNOSTIC PHASE

D-3.1 Normalized Root Mean Square (nrms)

(a) The nrms value, as computed from the NPSD and NCPSD, can be used as a check on values obtained during the surveillance program.

(b) The most accurate assessment of the amplitude of CSB motion can be obtained from a narrow-band (± 25%

[2] F. J. Sweeney, J. March-Leuba, and C. M. Smith, "Contribution of Fuel Vibrations to Excore Neutron Noise During the First and Second Fuel Cycles of the Sequoyah-1 Pressurized Water Reactor," *Progress in Nuclear Energy 15* (1985): 283–290.

of the core barrel frequency) calculation of the rms value based on the NCPSD of two diametrically opposite detectors.

(c) While the nrms value is an easily obtained parameter, its value alone is not an adequate measure of the amplitude of core barrel motion. Additional information on predominant frequency of the motion, based on cross-core coherence and phase information, is required for a complete assessment of the motion. These latter parameters can be obtained, in part from the NPSD and completely from the NCPSD.

D-3.2 Normalized Power Spectral Density (NPSD)

When compared with baseline values for that fuel cycle, NPSDs generally show an increase in amplitude with fuel burnup at lower frequencies (to approximately 0 Hz to 5 Hz) due to neutronic effects. This increase, depending on the core barrel frequency, may result in a broadening of the core support barrel motion-related peak.

D-3.3 Normalized Cross-Power Spectral Density (NCPSD), Coherence (COH), and Phase (ϕ)

The NCPSD, COH, and ϕ can be used in the diagnostic program to best ascertain the nature of the motion and determine if changes in wide-band or band-limited rms values from the surveillance program are related to changes in CSB motion. This would be done as follows:

(a) Note changes in coherence, in both magnitude and frequency of the maximum value, within the frequency range of core barrel motion. A change in frequency range of the coherence may be indicative of a change in frequency of core barrel motion. A change in amplitude may be indicative of a change in axes of motion.

(b) Note changes in phase within the same frequency range. A change in phase may be indicative of a change in axes of motion.

(c) Note changes in peak amplitude and frequency of this peak, both within and below this frequency range.

(d) Note changes in band-limited nrms amplitude in both core barrel frequency range and below this range.

A change in amplitude, frequency, and rms value may be indicative of a change in characteristics of core barrel motion, e.g., an increase in frequency may be due to a fixed end condition at one of the mechanical snubbers, while a decrease may be due to a lessening of the fixed end condition at the barrel-vessel flange interface. The latter may be due to a change in axial restraint, abnormal wear, or both.

D-3.4 Additional Sources of Information

To support the diagnostic phase of the program, other sources of information may be used, such as the following:

(a) loose parts accelerometers

(b) in-core detector noise

(c) loose parts monitoring system results

(d) core power distribution monitoring (tilts, axial flux changes, power peaking)

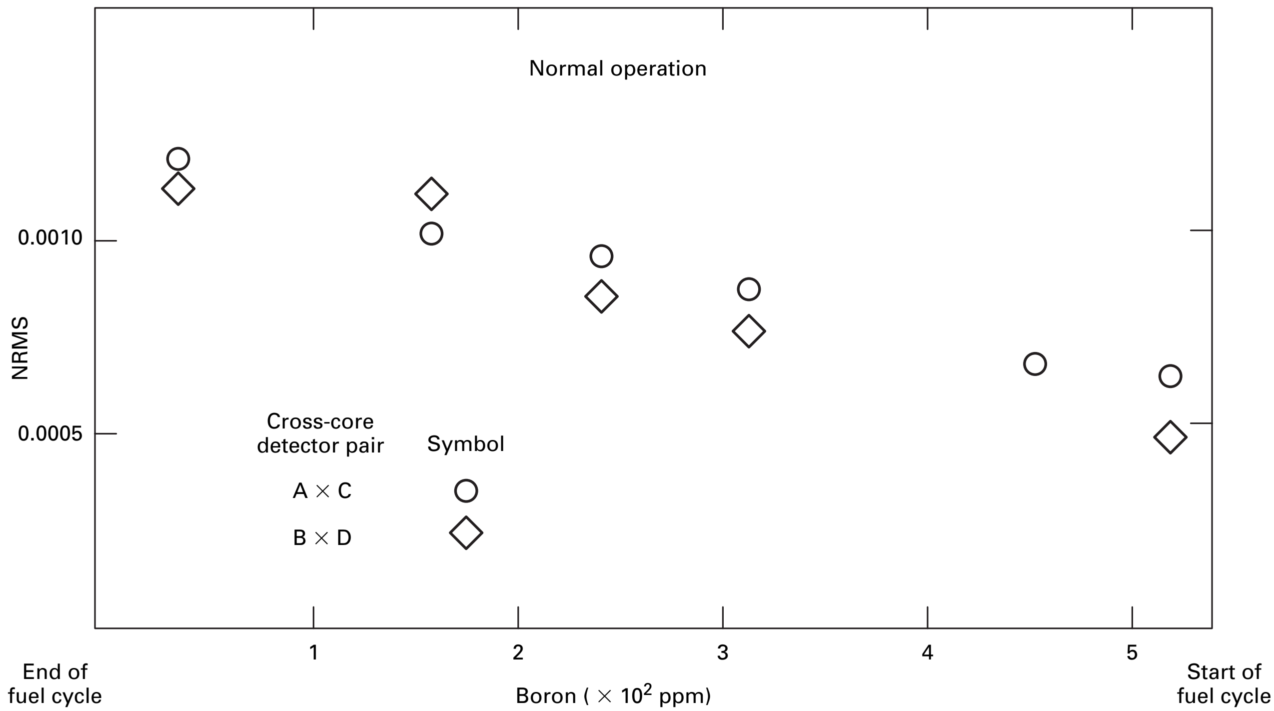
(e) primary pressure, temperature, flow distribution

(f) structural analysis of internal structures and boundary condition effects on frequencies and mode shapes

(g) plant operating history

(h) results from the Comprehensive Vibration Assessment Program for Reactor Internals During Pre-Operational and Initial Startup Testing Program (Regulatory Guide 1.20)

Fig. D-2 Example of Wide-Band rms Amplitude Versus Boron Concentration



PART 5
NONMANDATORY APPENDIX E
Guidelines for Evaluating Baseline Signal Deviations

Typical ex-core neutron noise signatures for six pressurized water reactors are shown in Fig. E-1 with the corresponding range in power spectral density shown in Fig. E-2.[1, 2] Changes in the neutron noise signature over a fuel cycle, including refueling, are shown for one plant in Fig. E-3.[1] For comparison, a neutron noise spectrum from a plant with a loss of axial preload on the core support barrel flange is shown in Fig. E-4.[3] These figures illustrate the range in neutron noise signature amplitude and frequency content between different plants and the major change in the shape of the core support barrel resonance frequency response region of the spectrum and a major increase in low frequency neutron noise associated with complete loss of axial clamping. Additional information on loss of axial preload obtained from reduced scale model tests is available.[4]

[1] D. N. Fry, J. March-Leuba, and F. J. Sweeney, "Use of Neutron Noise for Diagnosis of In-Vessel Anomalies in Light-Water Reactors," NUREG/CR-3303, ORNL/TM-8774 (Jan., 1984).

[2] D. N. Fry et al., "Noise Diagnostics for Safety Assessment Standards and Regulation," Quarterly Progress Report for April–June, 1978, NUREG/CR-0525, ORNL/NUREG/TM-278.

[3] Combustion Engineering Inc., unpublished data.

[4] C. Puyal, "Detection and Diagnosis of Mechanical Defects in Nuclear Components of French PWRs Using Noise Analysis Techniques," (London: CSNI Specialists Meeting on Continuous Monitoring Techniques for Assuring Coolant Circuit Integrity, Aug. 12–14, 1985).

Decreases in axial clamping force are expected to lead to decreases in the core support barrel beam mode frequency and to increases in the magnitude of the beam mode response. Criteria for entering the diagnostic phase should be based on a combined increase in core barrel resonance response rms amplitude and a simultaneous decrease in the core barrel beam mode resonance frequency, or a complete loss of the core barrel resonance frequency combined with a large increase in low frequency neutron noise.

Operating experience indicates that allowances must be made for increases in the neutron noise level as a function of core burnup and/or decreasing boron concentration, as well as for changes in fuel management and in core barrel contact with the reactor vessel mechanical snubbers that can affect the neutron noise signatures in some plant designs. These allowances will improve the ability to detect loss of axial clamping before the core barrel becomes completely free and capable of wear against the reactor vessel and will reduce the number of times that the diagnostic phase must be entered. The capability to develop these allowances on a plant-specific basis is provided by the baseline and surveillance phase data acquisition requirements.

Fig. E-1 Typical Ex-Core Neutron Noise Signatures From Six PWRs

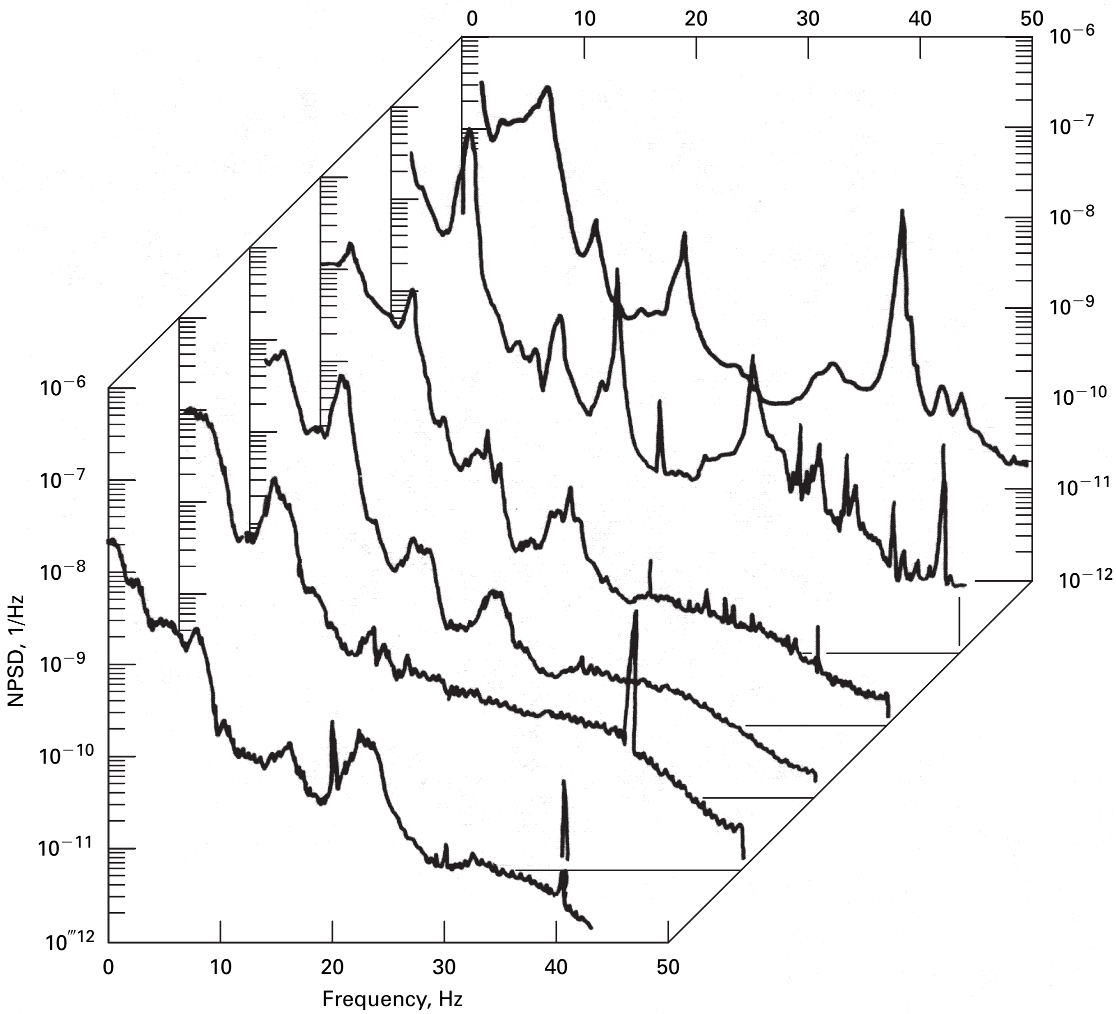
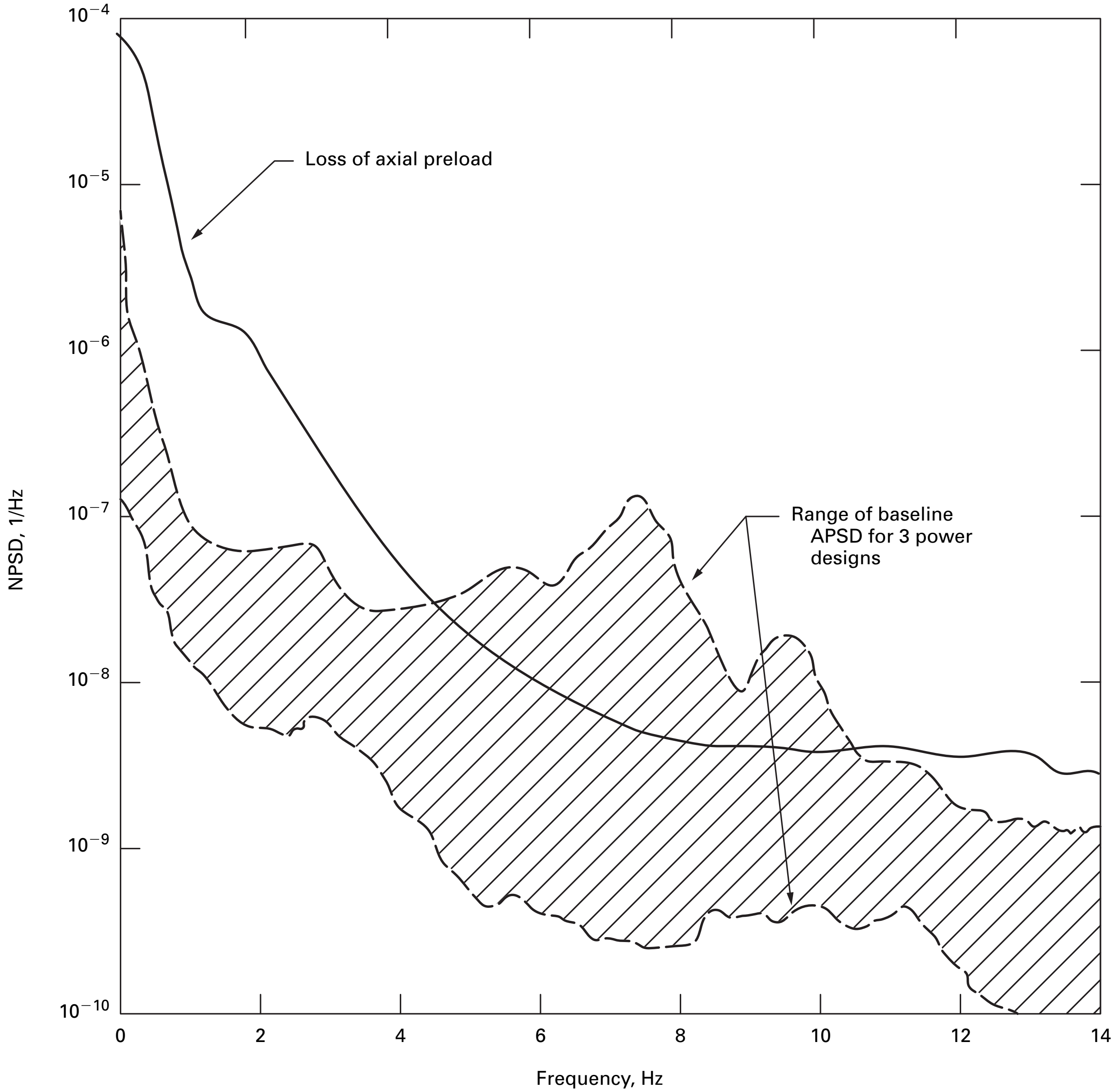


Fig. E-2 Typical Baseline NPSD Range



GENERAL NOTES:
(a) Range of Baseline nrms Values for Normal Operation 4×10^{-4} to 10×10^{-4}.
(b) Loss of Axial Preload nrms Value 0.02.

Fig. E-3 Examples of Changes in the Neutron Noise Signature Over a Fuel Cycle

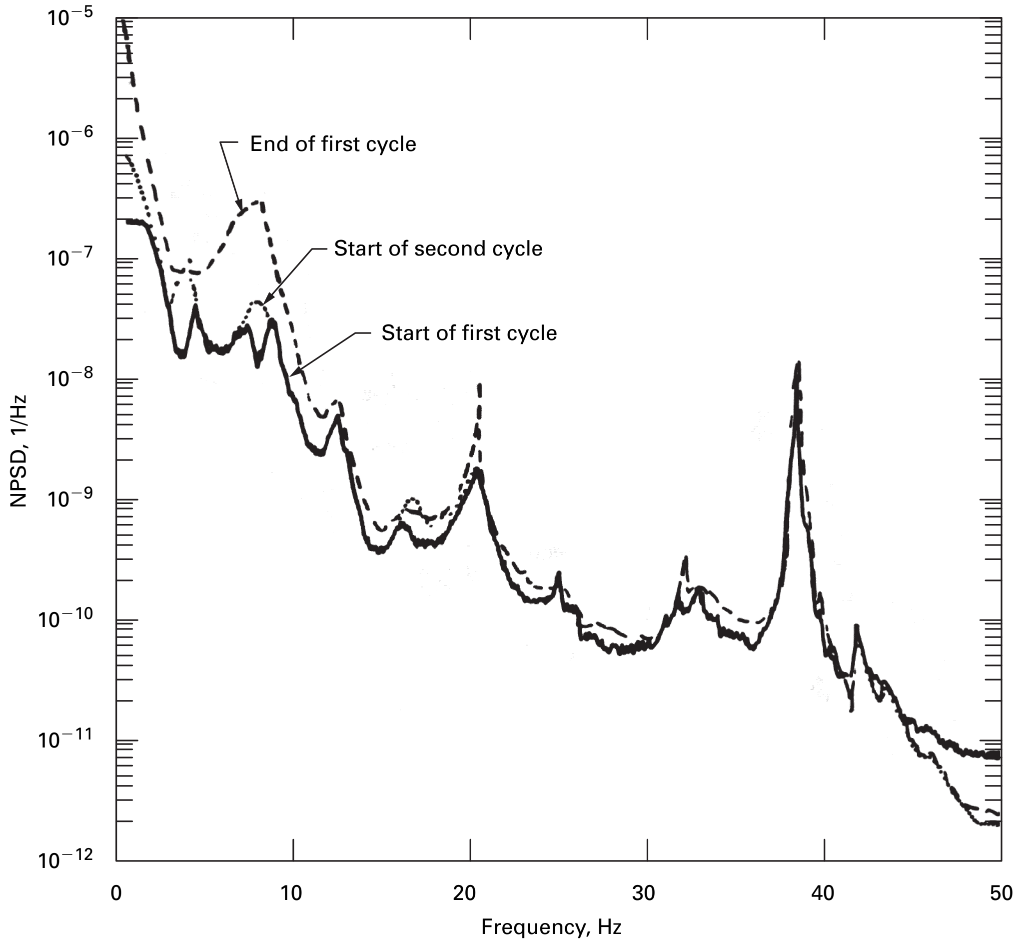
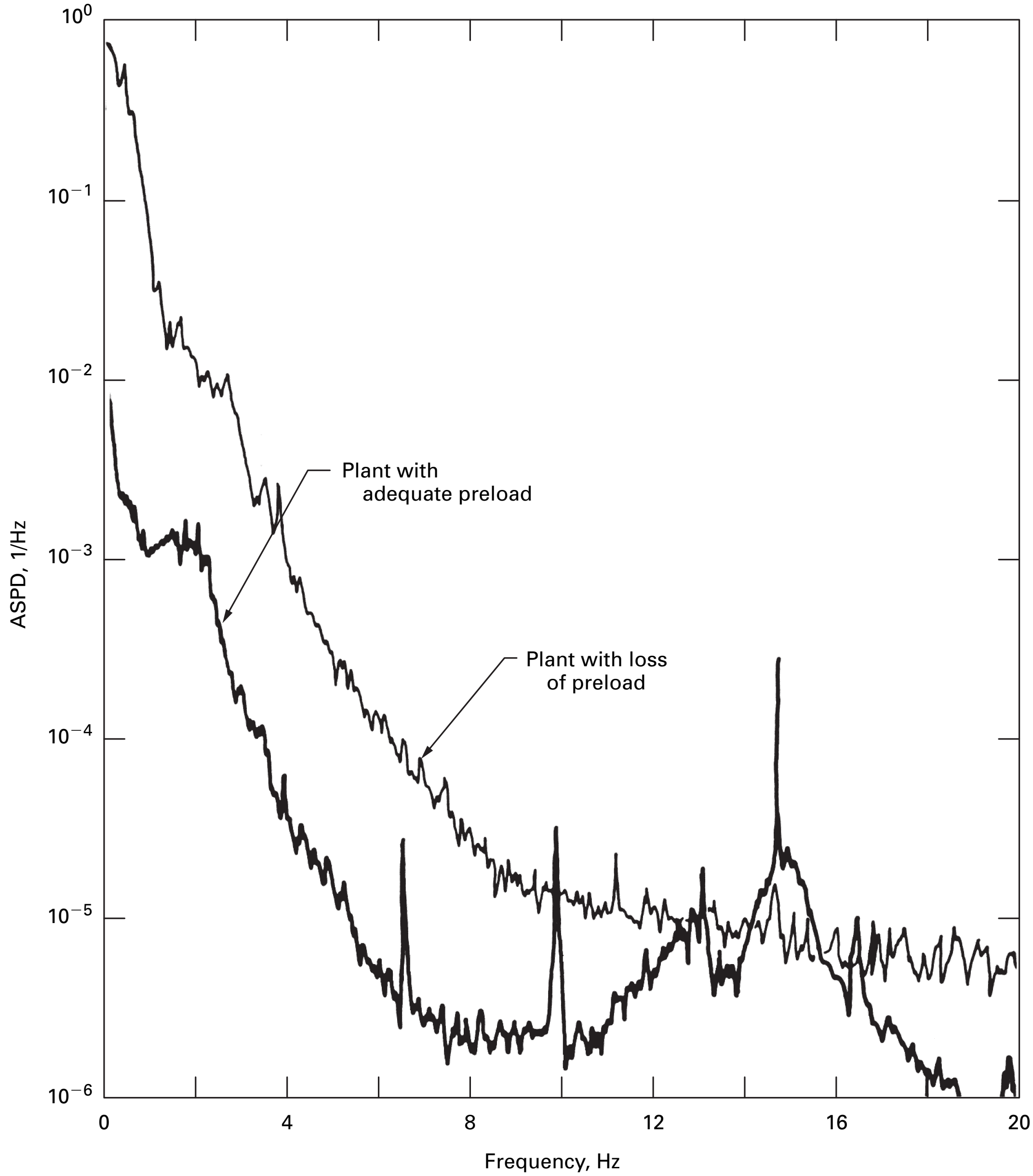


Fig. E-4 Example of Loss of Axial Restraint



PART 5
NONMANDATORY APPENDIX F
Correlation of rms Amplitude of the Ex-Core Signal (Percent Noise) and Amplitude of Core Barrel Motion

To convert amplitude of the neutron noise signal, expressed as fraction of noise (rms value of the random signal divided by the average or DC value of the signal at the same operating conditions), to amplitude of core barrel motion, expressed in units of length, a scale factor (1/length) relating these quantities must be found. This may be done by experimental and/or theoretical means for the specific reactor design. Table F-1 lists the range found in the referenced literature.

The values presented in Table F-1 are derived on the assumption that ex-core neutron noise resulting from core barrel motion is due only to neutron shielding (attenuation) effects. Experience in monitoring ex-core neutron noise has shown that additional noise sources (such as fuel motion, burnup, soluble boron, and moderator density changes) may be significant.[1] If these effects can be accounted for, the factors in Table F-1 may be used to estimate the amplitude of core barrel motion for a specific reactor design.

[1] F. J. Sweeney, J. March-Leuba, and C. M. Smith, "Contribution of Fuel Vibrations to Excore Neutron Noise During the First and Second Fuel Cycles of the Sequoyah-1 Pressurized Water Reactor," *Progress in Nuclear Energy 15* (1985): 283–290.

Table F-1 Ratio of the Amplitude of the Neutron Noise to Core Barrel Motion

Value, 1/mil (1/mm)	Comments
0.00038 (0.015) [Note (1)]	Measured; based on change of neutron flux with temperature
0.0003 (0.012) [Note (2)]	Calculated; one-dimensional transport model
0.00043 ± 0.000064 (0.0185 ± 0.00661) [Note (3)]	Measurements based on excore detector and core barrel accelerometer transfer function
0.00025/0.00015 max. (0.0098/0.0059) [Note (4)]	Maximum calculated by two-dimensional transport model (into shield/at shield surface); factor is a function of angle between axes of motion and detector location

NOTES:
(1) J. A. Thie, "Theoretical Considerations and Their Application to Experimental Data in the Determination of Reactor Internals' Motion From Stochastic Signals," *Annals of Nuclear Energy* 2 (1975): 253.
(2) M. Calcagno and F. Cioli, "Trino Vercellese Nuclear Power Plant Inservice Monitoring of Core Instructures and Reactor Internals by Neutron Noise Measurement," Ente Naccionale per l'Energia Elettrica Report, Rome, Italy (August 1970).
(3) J. P. Thompson et al., "Experimental Value of Ex-Core Detector Neutron Noise to Core Barrel Amplitude Scale Factor," *Transactions of the American Nuclear Society* 32 (1979): 797–798.
(4) J. C. Robinson et al., "Monitoring of Core Support Barrel Motion in PWRs Using Ex-Core Detectors," *Progress in Nuclear Energy* 1 (1977): 369–378.

PART 7

PART 7
Requirements for Thermal Expansion Testing of Nuclear Power Plant Piping Systems

1 SCOPE

This Part provides guidance for preservice and inservice testing to assess the thermal expansion of certain piping systems used in LWR power plants.

The piping covered is that 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.

This Part establishes test methods, test intervals, parameters to be measured and evaluated, acceptance criteria, corrective actions, and records requirements.

2 DEFINITIONS

The following list of definitions is provided to ensure a uniform understanding of selected terms used in this Part:

acceptable limits: specified range of numerical values of pipe response that satisfy acceptance criteria. An acceptable limit is usually expressed as the expected analytical response with an allowable range or tolerance.

ASME B31: ASME Code for Pressure Piping.

BPV Code: ASME Boiler and Pressure Vessel Code.

commercial operation: plant operation after completion of start-up testing.

design basis temperature: maximum temperature defined in the design basis thermal expansion analysis.

Design Specification: the document provided by the Owner, as required by NCA-3250 or NA-3250 of the BPV Code, Section III, for the component/system, which contains requirements to provide a complete basis for the construction of the component/system.

design verification: the process of reviewing, confirming, or substantiating a design by one or more methods to provide assurance that the design meets the specified design input.

discrepant response: thermal expansion response that falls outside acceptable limits.

hot shimming: the process of adjusting support and restraint clearances in the hot condition.

inaccessible piping: piping systems or portions thereof that are not accessible to personnel. The inaccessibility may be the result of adverse environmental conditions during the test, location of the piping, or mechanical or structural encasement.

initial start-up testing: test activity performed during or following initial fuel loading but prior to commercial operation. These activities include fuel loading, precritical tests, initial criticality tests, low power tests, and power ascension tests.

maintenance/repair/replacement: actions taken to prevent or correct deficiencies in the system operation.

normal operating conditions: the service conditions the system would experience when performing its intended function.

operational testing: test activities performed subsequent to initial start-up testing (e.g., testing performed during commercial operation of the plant).

Owner: the organization legally responsible for constructing and/or operating a nuclear facility including, but not limited to, one who has applied for or who has been granted a construction permit or operating license by the regulatory authority having lawful jurisdiction.

peripheral equipment: device(s) used in the setup, checkout, or on-site calibration of the other thermal expansion monitoring system (TEMS) devices.

physical units: the engineering units that quantitatively represent the measured variable (e.g., if the measured variable is displacement, the physical units can be inches, mils, meters, etc.).

piping system: an assembly of piping subassemblies and components and their supports whose limits and functions are defined in its Design Specification.

preoperational testing: test activities performed on piping systems prior to initial fuel loading.

processing equipment: device(s) used for further handling, reformatting, or manipulation of the transducer output to reduce it to manageable or intelligible information.

recording and display equipment: recording equipment devices are used for storing signals in a form capable of subsequent reproduction; display equipment devices are used to obtain a visual representation of a signal (conditioned and/or processed transducer output).

signal conditioner: device(s) used to modify or reformat the transducer output to make it intelligible to or compatible with processing equipment.

TEMS specification: a document that uniquely describes the thermal expansion measurement system.

test conditions: the conditions experienced by the system when undergoing tests.

test hold points: events in the test program usually associated with system operating conditions, for which test information is to be collected; for example, with the reactor at $X\%$ power or with the system at full flow.

test specification: the document(s) prepared by the Owner or his designee that meet the requirements set forth in para. 3.

thermal expansion measurement system (TEMS): the instrumentation or test equipment used to measure and record the thermal expansion data.

transducer: a device that converts the piping response into an optical, mechanical, or, typically, an electrical signal, which is proportional to a parameter of the piping response.

3 GENERAL REQUIREMENTS

The Owner shall determine and document the scope of piping systems to be monitored for thermal expansion during preoperational and initial start-up testing. The Owner shall also determine the monitoring techniques that would satisfy the minimum requirements for testing and acceptance criteria outlined in this Part.

The primary objective of the thermal expansion test program of a piping system shall be to verify that the piping system expands within acceptable limits during heatup and returns to an acceptable position when cooled down without adverse constraint. Acceptable limits shall be established using the considerations stated in para. 3.2.

The secondary objective of the test program shall be to verify that the component standard supports (including spring hanger, snubber, and strut) can accommodate the expansion of the pipe within the range of the component's capability for all specified modes of operation.

Other general requirements are as follows:

(a) A test specification for monitoring of thermal expansion of piping systems shall be prepared.

(b) Prior to testing of a piping system, a pretest walkdown shall be performed to ensure that construction is sufficiently complete for thermal expansion testing. The testing program and system completion requirements shall be consistent with the applicable construction code rules (e.g., ASME BPV Code, Section III). Any exceptions to the construction completion that affect thermal expansion testing shall be evaluated and documented.

The walkdown shall also verify that the anticipated piping movement is not obstructed by objects not designed to restrain the motion of the system (including instrumentation and branch lines). The system walkdown program shall verify that supports are set in accordance with the design.

(c) Selection of the locations and the types of measurements to be made shall consider the acceptance criteria and shall reflect any unique operational characteristics of the system being tested.

(d) When test results are to be correlated to specific analyses, test conditions and measurements should be specified in sufficient detail to ensure that the parameters and assumptions used in the analyses are consistent with those in the test.

3.1 Specific Requirements

Minimum requirements for thermal expansion testing of accessible, inaccessible, and small pipe (branch lines) are outlined below.

3.1.1 Test Specification

(a) The thermal expansion design basis of the system will be considered in the development of test specification requirements, selection of instrumentation, establishment of acceptance criteria and acceptable limits, and for review, evaluation, and approval of test results.

(b) The test specification shall include, as a minimum, the following:

(1) test objectives

(2) systems to be tested (including boundaries)

(3) pretest requirements or conditions

(4) governing documents and drawings

(5) precautions

(6) quality control and assurance (including required documentation and sign-offs)

(7) acceptance criteria

(8) test conditions and hold points

(9) measurements to be made and acceptable limits (including visual observations)

(10) types of instruments to be used and minimum instrument specifications

(11) data handling and storage

(12) system restoration

(c) The test specification shall be written in a manner so as to ensure that the objectives of the test as outlined in para. 3 are satisfied.

(d) In selecting locations for monitoring piping response, consideration shall be given to the maximum expected responses from the thermal expansion analysis. Locations with large expected movements should be monitored since these are convenient locations to look for general conformance of system response to analytic predictions. Specific consideration shall also be given to detecting evidence in the tests of the following:

(1) higher or lower than expected movements at the end of the first run(s) of pipe attached to component nozzles that may cause problems in stiff portions of the

system that are sensitive to the thermally induced loads (e.g., rotating equipment, thin wall vessels, heat exchangers).

(2) zero or out-of-range movement of the pipe at hanger or snubber locations; snubbers and variable spring hangers provide convenient devices for measuring thermal displacements.

(3) higher or lower than expected movement of the pipe adjacent to a structure requiring a controlled gap, e.g., at pipe whip restraints.

(4) discrepant piping responses, e.g., movements, stress, support loads, resulting from thermal stratification or thermal transients; Nonmandatory Appendix B provides descriptions and examples of thermal stratification and thermal transients.

(e) The response of the system shall be checked at the test hold points defined in the test specification to verify that the system is responding as expected.

(f) Actual pipe wall temperature should be considered in the evaluation of test results. For example, pipe wall temperature should be measured at various points along the piping system to ensure that the system has attained the desired test temperature. Consideration shall be given to the equipment movements and to nonuniform temperature distribution of system (e.g., branch piping with cold legs, thermal stratification, and thermal transients in applicable lines) prior to reconciliation, or prior to extrapolation (scaling) of results from a test condition to other operating temperature modes.

(g) For selected components in each system, spring travel and snubber movement shall be monitored and compared with acceptable limits. The number of monitored components shall be sufficient to define the response of systems.

(h) The maximum test temperature shall be as close as practicable to the maximum operating temperature of the system. The thermal expansion test shall be conducted in such a way that the response to the test conditions adequately represents the response to thermal modes of operation of the system.

(i) Small pipe (branch line) shall be checked in the vicinity of its connection to large pipe or equipment to ensure that sufficient clearance and flexibility exists to accommodate thermal movements of the large pipe or equipment.

(j) When the design requires hot shimming, an additional heat-up and cooldown cycle subsequent to the hot shimming should be performed to ensure correct response of the system.

3.1.2 Accessible and Inaccessible Piping

(a) Accessible piping shall be walked down at the specified test hold points to ensure that the objectives of the test are satisfied. Visual examination and measurements during walkdown using simple devices, including spring and snubber scales, are acceptable, unless the test specification requires more sophisticated measurement methods for greater accuracy.

(b) In the case of inaccessible piping, sufficient remote instrumentation shall be used to meet the test objectives.

3.2 Acceptance Criteria

When the test temperature is other than the design basis temperature of the piping, the acceptable limits shall be adjusted for the test temperature in checking compliance with the acceptance criteria. Acceptance criteria for thermal expansion of the piping system are as follows:

(a) The pipe shall move freely, except at the locations where supports/restraints are designed to restrain pipe thermal movement.

(b) Thermal movement of pipe at the locations of all spring hangers and snubbers shall be within their allowable travel range.

(c) The thermal movement of the pipe at the preselected measurement locations shall be within the acceptable limits specified or discrepant response shall be reconciled in accordance with para. 4. Acceptable limits of thermal response shall be established to ensure that applicable code allowable stresses and allowable equipment and nozzle reactions are not exceeded. Acceptable limits of thermal response shall consider the following:

(1) design basis thermal expansion analysis

(2) test temperature

(3) variations between actual system characteristics and analytical assumptions (such as support and equipment flexibility, gaps, and friction).

4 RECONCILIATION METHODS

Discrepant responses that are detected during testing shall be reconciled and/or corrective action shall be implemented (see para. 5) prior to acceptance of the test results. Reconciliation of the discrepant responses shall demonstrate that the requirements of para. 3 have been met.

The discrepant responses shall be evaluated and documented in conjunction with the results of the design basis thermal expansion analysis. The analysis input parameter and assumptions shall be checked against actual system characteristics. For example, this could include

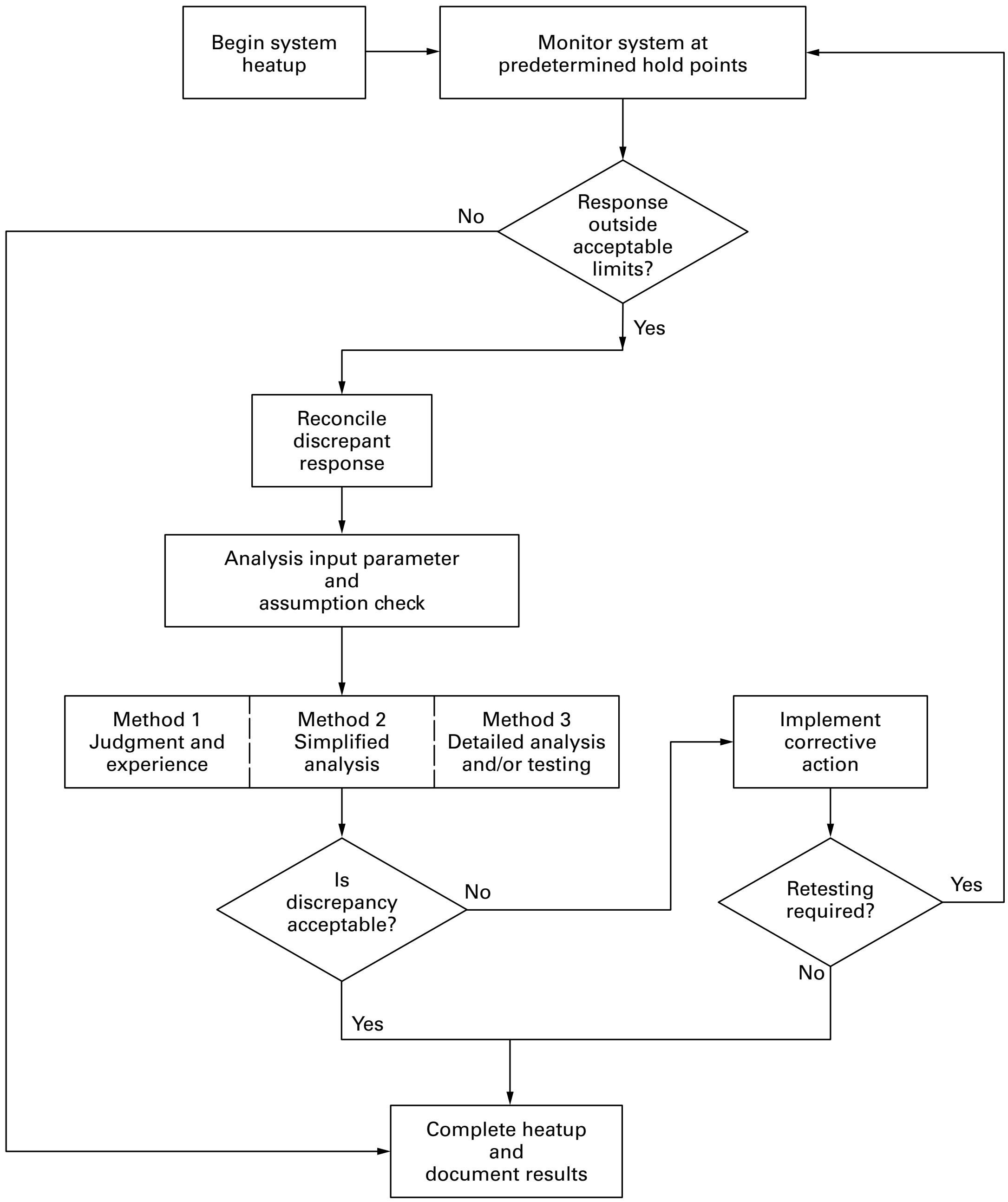
(a) actual test temperature variation along or around the pipe versus the temperature used in determining acceptable limits

(b) actual movement of equipment nozzles (including rotation) versus that used in the analysis

(c) binding of the pipe or spring hanger pins not pulled

If the discrepant responses cannot be reconciled, then corrective action shall be performed as detailed in

Fig. 1 System Heatup, Reconciliation, and Corrective Action



para. 5. Figure 1 depicts the steps involved in reconciliation and corrective action.

This paragraph provides suggested methods for the reconciliation of discrepant responses. Other methods may be used provided they conservatively predict pipe stresses and component reactions.

4.1 Reconciliation Method 1

Reconciliation of discrepant responses using this method is based on experience and documented engineering judgment. If more detailed assessments are required, Reconciliation Method 2 or 3 should be used. The basis for determining if the responses are acceptable shall be consistent with the requirements of para. 3.2.

The judgment of acceptability can be made only by evaluation and documentation of the following items as to their effect on piping stress and component reactions:

(a) applicability of assumptions made in the design basis thermal expansion analysis

(b) location and magnitude of thermal expansion stresses predicted by design basis analysis

(c) location and magnitude of discrepant responses

(d) proximity to sensitive equipment
(e) branch connection behavior
(f) capability of associated component supports
(g) unique system operational characteristics

4.2 Reconciliation Method 2

This method assesses the acceptability of the discrepant responses via simplified models of the affected segment of piping. The segment of piping affected by the discrepant responses can be modeled using appropriate simplified beam analogies. Simplified beam models are readily available in public literature. Alternatively, a simplified computer model of the affected piping segment can be used to assess the effects of the discrepant responses.

The objective of the model used is to obtain a conservative quantitative evaluation of the thermal expansion effects. One simplified model may be required to conservatively predict pipe stress, but a different simplified model(s) may be required to conservatively predict support loads on component reactions. The acceptability of the evaluation shall be based on the criteria delineated in para. 3.2.

The considerations specified in para. 4.1 are also applicable to Reconciliation Method 2.

The simplified beam or computer models suggested in this paragraph should result in conservative predictions of stresses and support and equipment loadings. Reconciliation Method 3 may be used to eliminate some of the conservatism inherent in these models.

4.3 Reconciliation Method 3

This method requires a detailed assessment of the discrepant responses. This is accomplished through the use of detailed testing and/or analysis. The objective is to obtain additional data to determine a more accurate and less conservative representation of the system. If the results of the detailed testing and/or analysis demonstrate that the system response is within the requirements of para. 3.2, then the response is acceptable.

Detailed analysis may involve incorporation of the actual measured response of the system into the design basis analytic model to obtain forces and stresses.

5 CORRECTIVE ACTION

When the discrepant responses cannot be reconciled, corrective action shall be implemented prior to acceptance of the test. The objective of corrective action is to identify and eliminate the cause of the discrepant responses or to mitigate their effects.

Possible corrective actions typically fall into the following categories.

(a) Eliminate Interference. Interference can result from thermal expansion displacements exceeding the clearances between the pipe and pipe supports, building structures or other surrounding structures, or equipment. Eliminating the interference involves complete or partial removal of the interfering structure.

(b) Modify Support System. Support malfunction, inadequate support operating ranges, or improper cold settings can result in the support interfering with the pipe expansion. Corrective action involves replacing or readjusting the supports. Supports may be replaced with supports of different operating ranges, supports of different types (for example, replace rigid with snubber), or supports with different flexibility characteristics. Additionally, supports may be eliminated to increase the system flexibility, or supports may be added to redirect the system expansion movement.

(c) Modify Pipe Routing. Corrective action may involve rerouting the piping to avoid obstructions, to redirect the expansion movement, or to increase flexibility through the addition of expansion loops.

(d) Modify Operating Procedures. Corrective action may involve modifying operating procedures, such as avoiding unnecessary injection of hot fluids into certain piping systems.

After corrective action is implemented, and if the corrective action can affect the thermal expansion response of the system, then additional testing shall be performed to determine if the system response meets the requirements of para. 3.2.

If corrective action results in hardware modifications, then the piping system design basis analysis shall be reviewed and revised, as required, to include the effects of the corrective action.

6 INSTRUMENTATION REQUIREMENTS FOR THERMAL EXPANSION MEASUREMENT

This paragraph provides requirements for the instrumentation and recording equipment necessary to meet the minimum data acquisition and reduction requirements for thermal expansion testing of piping systems. Recognizing the constant advancement of instrumentation and data acquisition equipment, this paragraph is not intended to explicitly require certain instruments or techniques. Rather, this paragraph sets forth the criteria necessary to ensure that the data taken by any method is accurate, repeatable, and within the capabilities of the method or equipment being used. A typical TEMS is shown in Fig. 2.

Nonmandatory Appendix A contains guidelines and precautions for typical TEMS. Appendix A can be used as a basis for the specification of the instrumentation/measurement system to be used during testing.

6.1 General Requirements

The systems and techniques used for measuring the thermal expansion of all piping systems covered by this Part shall meet the following minimum requirements.

Fig. 2 Typical Components of a TEMS

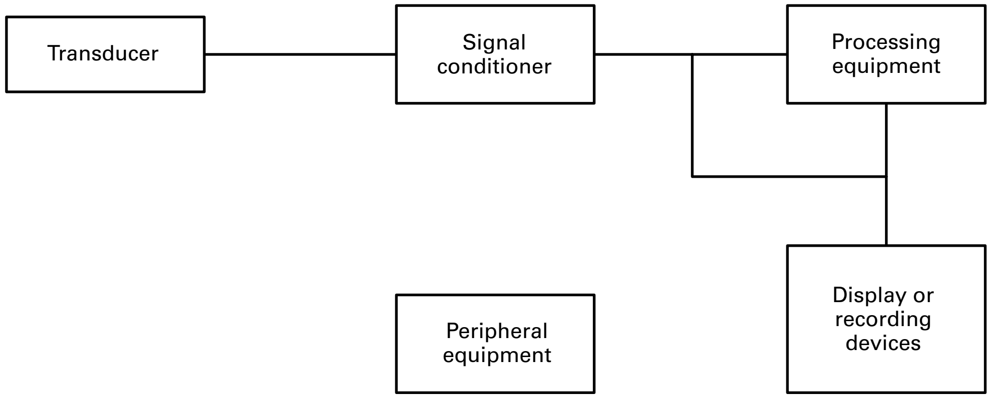


Table 1 An Example of Specification of TEMS Minimum Requirements

Acceptable limit	Minimum value (D_{min}) = 1.0 in. (2.54 cm) Maximum value (D_{max}) = 1.5 in. (3.8 cm)
Accuracy	±0.1 in. (±10% of D_{min}) (± 0.254 cm)
Minimum measurable value	+0.8 in. (80% of D_{min}) (+ 2.0 cm)
Full-scale range	+1.8 in. (120% of D_{max}) (+ 4.6 cm)
Stability	±0.05 in. (±5% of D_{min}) (± 0.13 cm)
Frequency response	Static
Other (max. pipe temperature)	300°F (149°C)

6.1.1 TEMS Specification. A TEMS specification shall be included in or referenced by the test specification and shall include the following:

(a) functional description.

(b) list of equipment (Manufacturer, model number, serial number).

(c) equipment calibration record.

(d) equipment specifications.

(e) installation specifications.

When visual means (such as rulers or scales) are the only methods used to measure the thermal expansion of the system, the requirement for a TEMS specification may be waived; however, the methods used shall be documented.

For the TEMS as well as each device comprising the TEMS, the information and minimum requirements listed below shall be contained in the TEMS specification when applicable. An example of the specification of the TEMS minimum requirements is given in Table 1.

(f) inputs and outputs: units and full-scale range of each.

(g) accuracy: specified as a percentage of full-scale physical units.

(1) TEMS minimum requirement: ± 10% of the minimum acceptable limit.

(h) minimum measurable value.

(1) TEMS minimum requirement: accurate readings from the TEMS should be obtainable when the measured variable reaches 80% of the minimum value of the acceptable limit.

(i) range: full-scale capability with accuracy specification.

(1) TEMS minimum requirement: accurate readings from the TEMS should be obtainable until the measured variable reaches 120% of the maximum value of the acceptable limit.

(j) stability: allowable variation of initial zero or reference setpoint when subsequent measurements are made with respect to that initial setpoint.

(1) TEMS minimum requirement: ± 5% of the minimum acceptable limit.

(k) frequency response.

(1) TEMS minimum requirement: capable of measuring static data.

(l) calibration data: specific requirements are given in para. 6.1.2.

(m) other specifications: any other specifications unique to the measurement system or important for the accurate measurement of the variable, such as temperature compensation or mounting requirements.

Manufacturer's specifications are acceptable for each device comprising the TEMS; however, care should be exercised that the application, mounting, and interfacing conditions do not affect or invalidate the manufacturer's specifications. This is especially important in transducer mounting and electrical loadings.

6.1.2 Calibration. All equipment used as part of the TEMS shall have current calibration documents. These shall be attached to or made part of the system specifications. On-site checkout of the TEMS shall be performed to verify that the as-installed TEMS is functioning according to the system specification.

6.1.3 Repeatability. Capability of the TEMS to provide consistent results shall be demonstrated. This can be achieved by taking several consecutive measurements of a stationary variable during pretest setup and checkout. The results of these consecutive measurements should be within minimum accuracy requirements of the TEMS specification.

6.1.4 Acceptability of Measurements. Measured data is considered acceptable for evaluation with respect to acceptance criteria provided that it falls within the capability of the TEMS as prescribed by the TEMS specifications. Measurements that fall outside the TEMS capability must be remeasured using an appropriate technique.

6.2 Precautions

The requirements given above for the specifications of the TEMS represent the minimum necessary to ensure accurate measurement of thermal expansion data.

In developing these minimum requirements, it was assumed that the acceptable limits represent ranges of thermal expansion for which there is a high level of confidence that the measurements will fall within 20% of the expected ranges. Although not required, it is recommended that the TEMS be specified to have a broader capability with respect to minimum measurable value and full-scale range. This will allow the measurement of thermal expansions that are not within 20% of the acceptable limits and should minimize the amount of retesting required.

PART 7
NONMANDATORY APPENDIX A
Guidelines for the Selection of Instrumentation and Equipment of a Typical TEMS

The purpose of this Appendix is to provide tables from which the user of this Part may select the components that comprise a thermal expansion measurement system. Recognizing the wide range and selection of available equipment, Tables A-1 through A-4 are not meant to be all-inclusive. Rather, they represent typical equipment in use at the time this Part was prepared.

The tables are organized with respect to the generic basic components of the TEMS as described in para. 6.

For each typical device listed, information regarding such areas as function, application, and limitations is given as an aid in the selection process.

Table A-1 Typical Transducers

Device	Basic Function or Application	Precautions/Limitations
Ruler, scale	A hand-held device for direct measurement of displacement from a fixed reference, read visually at location of measurement	Requires personnel at measurement location Limited accuracy of $^1/_{16}$ in. (1.6 mm)
Dial indicator	A mechanical device mounted to a fixed reference point at the measurement location, displacement visually read by dial and pointer	Very good accuracy, but typically a function of range Must be securely mounted Zero setting very sensitive to mounting stability
Lanyard	An electromechanical device consisting of a cable, spring, and resistive potentiometer that provides an electrical signal proportional to the displacement of the cable end	Accurate, stable, and easily mounted Provides for centralized monitoring of many points Signal conditioners required
LVDT	An electromechanical device that produces an electrical output proportional to the motion of a magnetic core inside three coils	Provides high accuracy and resolution Loading of test object is minimal since only the core is attached to the moving object Requires signal conditioning with AC excitation More fragile than lanyard transducers
Proximity probe	An electrical eddy current device that produces an electrical output proportional to the gap between the probe and the monitored object	Linear range is limited to variations about the initial gap Requires power supply and proximitor Provides high accuracy and resolution
Thermocouple	An electrical device that produces a voltage proportional to the difference in temperature between two junctions of dissimilar metals	Readily available in a variety of configurations Rugged, easily mounted Provides for centralized monitoring of many points Requires use of a reference junction Voltage output is not linear with respect to temperature
RTD	A resistance temperature detector that changes the resistance of the sensing element proportions to its temperature	Readily available, easily mounted Provides centralized monitoring of many points Does not require use of a reference junction Not as rugged as thermocouples Resistance change is not linear over a wide temperature range May be prone to self-heating effects if continuously excited
Strain gage	An electrical device that measures surface deformation of the test object. The most common type uses the change in resistance of a foil or wire grid intimately bonded to the surface of the test object to indicate the average strain over the grid length.	Provides actual strains in the piping instead of displacements High temperature use may require welding or post-curing of adhesives Temperature compensation, long-term stability and hysteresis effects may be sources of problems

Table A-2 Typical Signal Conditioners

Device	Basic Function or Application	Precautions/Limitations
DC amplifier	Electronic device used to amplify the signals supplied by lanyards, LVDTs, thermocouples, strain gages, etc.	Provides high level signals for ease of reading or recording Gains must be recorded for units with switchable gain settings Units for static measurements should have minimal zero drift
Power supply	Provides constant power signal to LVDTs, proximity probes, strain gages, and lanyards for signal generation	May provide either AC or DC power in accordance with transducer requirements Power regulation must be within either transducer manufacturer's specifications or within system accuracy requirements Total transducer loading on the power supply must not exceed rated capacity
Reference junction	Provides or simulates a known temperature at one junction of a thermocouple, so that absolute temperature at the other junction may be found	Some reference junctions are made for specific types of thermocouples. They may be used only with that type. Since reference junctions will often be used near the measurement location, care must be used to ensure that the ambient temperature does not exceed the equipment capabilities

Table A-3 Typical Processing Equipment

Device	Basic Function or Application	Precautions/Limitations
Data logger	Provides analog to digital conversion of transducer or signal conditioner output; automatically scans, processes, and records multiple channels of data	Processing capabilities may require computer controls. Output capabilities may require a computer interface.
Minicomputer	Provides control, processing, storage, and output functions when used with a data logger or analog to digital converter	Has greatly expanded processing and output capabilities compared to a data logger Requires much time for setup and programming of a new system
Voltmeter	Can be used to measure voltage or resistance of electrical circuits	Slow device — requires manually repositioning probes for each reading Requires manual recording and processing of data

Table A-4 Typical Display/Recording Equipment

Device	Basic Function or Application	Precautions/Limitations
Tables and graphs	Printed material in appropriate format to manually log test data and measured values	Manual logging of data will be a time-consuming process in comparison with automated procedures
Strip charts	Continuous time history plots produced by a mechanical recorder	These are only practical for a relatively small number of channels in comparison to data loggers or minicomputers
Oscilloscope	A device to display an electrical signal in graphical form upon the screen of a cathode-ray tube	Due to the time limitations upon the display, it will only be useful for rapidly occurring events Oscilloscopes typically do not produce permanent records
Printed tables	The paper output produced by data loggers or minicomputers that contains data printed out in numerical form	Large volumes of output may be produced
Analog or digital tape recorder	A device to store/replay information using varying local magnetization of a moving strip of plastic that has been coated with a metallic material	Useful for storing large amounts of data in a compact form Retrieval of the data requires use of equipment similar to that used for recording

PART 7
NONMANDATORY APPENDIX B
Thermal Stratification and Thermal Transients

B-1 INTRODUCTION

Thermal conditions may occur in piping systems that could result in high internal forces and moments causing piping or support damage. This Appendix describes thermal stratification and valve leakage conditions that have occurred in nuclear power plants and have caused anomalous system response or piping and support damage. It is the intent of this Appendix to describe several occurrences to assist in root-cause evaluations.

B-2 THERMAL STRATIFICATION

Thermal stratification is a phenomenon that can occur in any stagnant or low-velocity single-phase fluid or stratified two-phase flow. It can be caused by low flow rates into a pipe containing different temperature fluid. It manifests itself as a nonlinear temperature gradient occurring predominantly in horizontal sections of pipe (see Fig. B-1). The phenomenon occurs when hotter (less dense) fluid floats on top of cooler (more dense) fluid. This tendency to separate is caused by the buoyancy or density differences of the two fluids. Under nonturbulent, low-velocity flow, the two fluid layers do not have time to achieve a steady-state homogeneous temperature profile and tend to remain separated. However, under high flow rates, the fluid flow becomes turbulent, which promotes mixing of the two fluid layers, resulting in a homogeneous temperature profile.

The temperature profile typically manifests itself as two volumes of almost constant but different temperatures separated by a relatively small temperature transition zone. Measurements have been made in some fluid systems indicating difference in temperatures as high as 320°F (178°C). Higher differences are also possible. During other operating modes, the same system exhibited temperature differences between 0°F (−18°C) and 100°F (38°C).

Thermal stratification has been observed in PWR surge lines. The surge line connects the reactor coolant loop (RCL) with the pressurizer. The pressurizer is typically at a higher temperature than the RCL since it contains electric heating elements that maintain the fluids at saturated conditions. Under startup (steam bubble formation) and normal operating conditions, fluid temperature inside the pressurizer ranges between 400°F (204°C) and 650°F (343°C), while the RCL temperature typically varies between 120°F (49°C) and 615°F (324°C). It is this large difference in temperature between the pressurizer and the RCL that provides the difference in temperature of the fluid in the surge line. Fluid is exchanged between the pressurizer and the RCL as the system maintains the desired pressure using heaters and spray. As the RCL fluid temperature increases, the RCL fluid volume increases, causing an insurge of fluid into the pressurizer; at the same time, some of the hotter fluid flows out of the pressurizer to heat the reactor coolant system (RCS). These flows are generally slow and laminar, resulting in conditions conducive to thermal stratification. During conditions of high flow in the surge line (caused by reactor coolant pump start/stop, rapid boron injection, or activation of the pressurizer spray valves), the high velocities tend to mix the fluids, creating a homogeneous thermal condition. However, upon return to normal flow in the surge line, the fluids again return to a stratified flow condition.

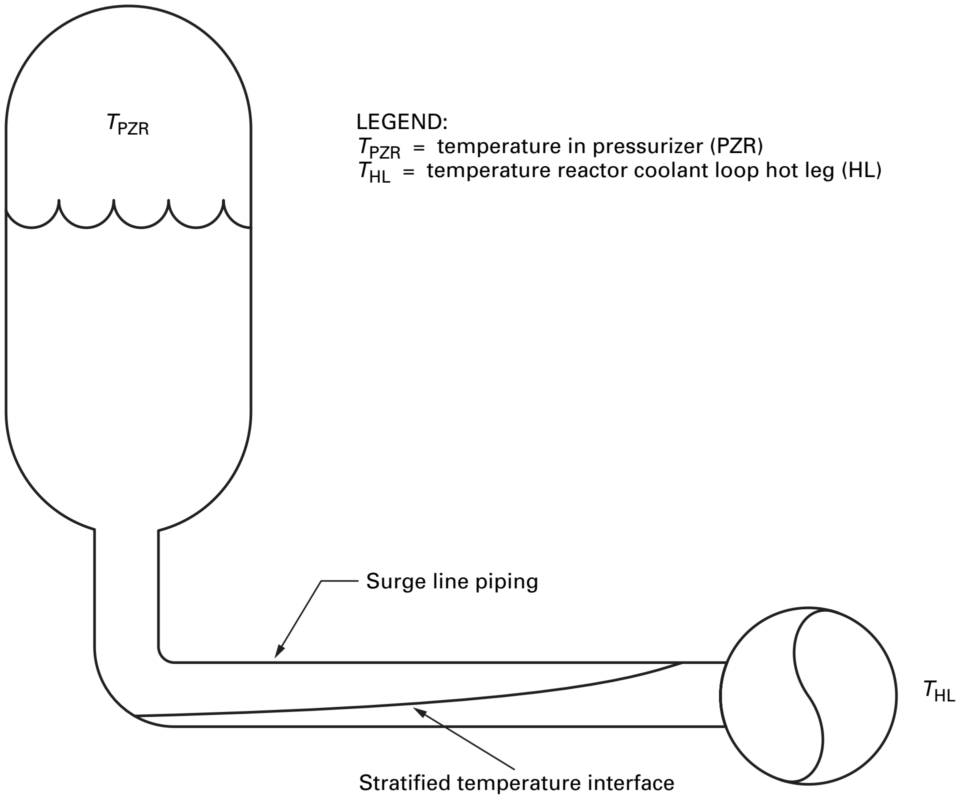
The differences in temperatures cause the pipes to assume a circumferential temperature gradient. This gradient causes the pipe to bow, typically in the vertical plane. This vertical bowing can create unanticipated internal forces and horizontal or vertical movement in a complex three-dimensional piping system. This unanticipated movement could result in unintentional restraint of the piping system (e.g., gaps on rigid restraints close, snubber movements exceed allowable limits, or pipe contacting pipe rupture restraints).

The stratification phenomenon depends on piping system geometries. Valves, elbows, reducers, and orifices tend to create turbulence in the flow steam and, thus, could reduce the severity of stratification.

In some PWR designs, the auxiliary feedwater (AFW) system supplies fluid to the steam generator via main feedwater (MFW) piping. The MFW and AFW systems have also been reported to exhibit thermal stratification under certain operating modes and system alignment. The MFW contains larger pipe sizes and higher temperature fluid than the AFW piping system.

When flow in the MFW system ceases and AFW is initiated, cooler AFW fluid is injected into the larger, hotter MFW piping, which is at a higher temperature. Due to the large difference in pipe size, the velocity of the AFW fluid in the larger MFW line is significantly reduced. The large difference in temperature coupled

Fig. B-1 Simplified Schematic of Surge Line Stratification



with the greatly reduced flow rate are conditions that could result in stratified flow.

Other systems in which flow stratification has been reported are pressurizer spray systems, reactor core isolation cooling systems, and reactor water cleanup systems.

Striping is a phenomenon associated with thermal stratification and has been shown, in cases investigated thus far, to be an insignificant factor in causing fatigue damage to piping systems. Striping is a phenomenon where two fluids at different temperatures are separated by an interface that tends to oscillate about its equilibrium condition. This oscillation causes alternating heating and cooling of a region of the pipe that can theoretically lead to fatigue damage.

B-3 THERMAL TRANSIENTS

The majority of thermal transient conditions are anticipated and included in the analysis of ASME piping systems. Occasionally, new transients are discovered or defined. Some of these are due to changes in operating conditions, the addition of new systems, or discovery of new phenomena.

In other cases, the malfunction of a component, such as a valve, can result in leakage between two normally isolated sections of a piping system. These two normally isolated sections can contain fluids at different temperatures and pressures. The differential pressure creates a driving head that causes fluid flow. The injection of fluid at temperature into a section of pipe containing fluid at a different temperature will initially cause a thermal stress cycle in the pipe.

If the leakage is constant, stress reversals will occur only during plant/system startups and shutdowns, resulting in a relatively few number of stress cycles and, therefore, no significant increase in the fatigue cumulative usage factor. However, if the leakage occurs intermittently, a fatigue crack can be initiated, propagated, and can potentially cause a breach in the pressure boundary. Such intermittent flows can occur, for example, when a normally closed valve leaks and causes a change in the temperature of the valve disk. The change in temperature of the valve disk can cause thermal growth of the disk and resealing of the flow path. Upon cessation of the flow, the separated sections tend to return to the thermal conditions that existed when the leak initiated. Repetition of this sequence could occur frequently, and with sufficiently high temperature differences could result in large numbers of stress cycles and possible thermal fatigue damage of the pipe. It is difficult to determine, without monitoring, whether a leak is continuous or intermittent.

(a) Three conditions must be present to create this condition

(1) leakage by the valve seat

(2) pressure differences across the valve seat

(3) temperature difference on both sides of the valve seat

(b) Such low leakage rates can easily go undetected. There are several techniques available that may detect leakage past a valve seat, such as

(1) visual inspection (intrusive)

(2) acoustic monitoring (nonintrusive)

(3) temperature monitoring

PART 11

PART 11
Vibration Testing and Assessment of Heat Exchangers

1 INTRODUCTION

1.1 Scope

This Part provides guidance for preservice and inservice testing to assess the vibration of certain heat exchangers used in light-water reactor (LWR) power plants. The heat exchangers covered are those 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. This Part establishes test methods, test intervals, parameters to be measured and evaluated, acceptance criteria, corrective actions, and records requirements.

2 DEFINITIONS

The following list of definitions is provided to ensure a uniform understanding of selected terms used in this Part:

acceptance criteria: criteria that establish whether or not further investigation or follow-up actions are needed based on results of the vibration assessment.

conditions: primary and secondary fluid temperatures, pressures, and flow rates; settings of valves in piping adjacent to the heat exchanger.

first of a kind: a heat exchanger having a design, operating condition, or installation that differs significantly from heat exchangers that have been tested or that have an adequate operating experience.

flow rate plateau: a flow rate at which steady-state conditions are maintained and data are acquired.

normal operating conditions: the service conditions a heat exchanger would experience when performing its intended function.

operating limitations: limitations on heat exchanger operating conditions to prevent unacceptable vibrations.

Owner: the organization legally responsible for the construction, or operation, or both, of a nuclear facility including but not limited to one who has applied for, or who has been granted, a construction permit or operating license by the regulatory authority having lawful jurisdiction.

shell-side flow: the flow in passages between the outside of the heat exchanger tubes and the inside of the shell.

steady state: the state in which conditions do not change with time and during which initial transients or fluctuations have disappeared.

tube-side flow: the flow inside the heat exchanger tubes.

NOTE: Definition of wave analysis terms such as *power spectral density, cross-power spectral density,* and *coherence* can be found in the reference of para. 3(a).

3 REFERENCES

The following is a list of publications referenced in this Part.

ANSI S2.10-1971, Methods for Analysis and Presentation of Shock and Vibration Data

Publisher: American National Standards Institute (ANSI), 25 West 43rd Street, New York, NY 10036

M. K. Au-Yang and K. P. Maynard, "Guidelines for the Reduction of Random Modal Test Data," Proceedings of the 3rd International Modal Analysis Conference, Orlando, FL, Vol. 1

Publisher: Union College Press

4 BACKGROUND DESCRIPTION

Heat exchangers of various types and service requirements are used extensively in nuclear power plants. As examples, a typical boiling water reactor (BWR) plant may have as many as 30 heat exchangers while a pressurized water reactor (PWR) plant may have between 50 and 60 heat exchangers. These heat exchangers can range in size from a 2 gpm (126 cm^3/hr) 10 tube distillate cooler to a 58,200 tube condenser and can include straight, U-tube, coil, and hairpin configurations. The various shell- side fluids include air, steam, water, glycol, hydrogen, and oils. In general, heat exchangers that can directly affect the operability or safety, or both, of the plant are the units of most concern. These include, for example, steam generators with primary coolant on the tube side, feedwater heaters, condensers, and residual heat removal heat exchangers.

There is a history of tube vibration problems in shell-and-tube heat exchangers used in the power and process industries. For the most part, the tube vibration is induced by the shell-side cross-flow, which represents a source of energy that can excite and sustain vibration. The mechanisms responsible for exciting tube vibration are addressed in Nonmandatory Appendix A.

While a tube bundle vibration analysis will provide important design guidance, available information and experience to support assumptions in the analysis may not allow for sufficiently accurate prediction of actual vibration behavior. Therefore, a program of vibration measurement is often needed to determine whether vibration levels are acceptable.

The intent of the vibration assessment in this Part is to minimize impact on plant operation by early identification of excessive vibration levels. The primary application is for first-of-a-kind heat exchanger designs. Other applications would be for heat exchanger designs suspected to be susceptible to excessive vibration based on the following:

(a) operating experience of similar units

(b) design calculations

(c) a need to operate the heat exchanger at higher flow rates

This Part can also be applied to evaluate the effectiveness of modifications.

5 SELECTION OF EQUIPMENT TO BE TESTED

5.1 Equipment Selection Factors

Factors to be considered in establishing the need for a test and in selecting the type of measurement shall include at least the following:

(a) the importance of the heat exchanger

(b) previous operational experience with a similar design

(c) available design analysis and laboratory test data

(d) equipment configuration

5.1.1 A large nuclear steam generator of essentially new design, the failure of which may cause major impact on plant operation, shall be tested by the Direct Method (see paras. 6.1 and 7.1). Prior test results and operational experience may be used (in lieu of new tests) to demonstrate the adequacy of a heat exchanger under the following conditions:

(a) The design of the heat exchanger under consideration is "sufficiently similar" to a reference design (prototype) with proven structural integrity to permit a comparative flow-induced vibration analysis, using the reference design as the basis.

The following factors shall be considered to establish that a new design is sufficiently similar to the reference design:

(1) geometries, size, materials, and fabrication processes

(2) shell-side and tube-side fluid velocity and density distribution

(3) environmental conditions such as temperature, pressure, and water chemistry

(b) A comparative analysis shows that the heat exchanger under consideration is no more susceptible to fluidelastic instability, turbulence, and vortex-induced vibration than the reference design and, consequently, is subject to no more flow-induced wear and fatigue than the reference design.

A comparative flow-induced vibration analysis is one in which the empirical input parameters in the vibration prediction equations are common to, or can be simply extrapolated from, those of the reference design. The new design is "sufficiently similar" to the reference design if the factors in paras. 5.1.1(a)(1) through (3) do not invalidate these simple extrapolations. Nonmandatory Appendix B includes correlations that may be used in lieu of more specific information.

5.1.2 For steam generators or other heat exchanger designs that are similar to a reference design in accordance with paras. 5.1.1(a)(1) through (3), but have some geometry or flow differences that do not significantly change the flow distribution in the heat exchanger or tube support conditions and probabilities, an in-plant tube vibration measurement program is not required if the following apply:

(a) Prior test results and operational experience on unit(s) exhibiting no unacceptable tube wear over extended time are available for the reference design.

(b) Analysis results for the design under consideration show that the margins for fluidelastic instability, turbulence, and vortex-induced vibration are adequate to accommodate uncertainties in the analysis and uncertainties in criteria established from laboratory testing, plant testing, and experience.

(c) The laboratory tests are shown to be applicable to the operating conditions of the steam generator or heat exchanger.

It is suggested that the Owner review the planned or available laboratory tests; plant test results; and experience, analysis, and criteria and agree that these are sufficient to demonstrate the adequacy of the design under consideration.

5.1.3 Examples of differences that might be shown to be acceptable according to paras. 5.1.2(a) through (c) are as follows:

(a) changes in tube support bundle pitch or pattern, where the fluidelastic stability constant for the design under consideration has been established by laboratory testing

(b) changes in tube support spacing or hole geometry without a significant increase in clearance at the tube support

(c) modest flow increases, such as the increases associated with power upratings

System (piping and valve configurations) and heat exchanger supports should be similar if previous experience is to be applied. Changes in the fluid system or heat exchanger supports could result in flow imbalance or tube support motions that are reflected in tube vibration.

For some heat exchanger designs, mechanical testing to determine dynamic characteristics of tubes may support the similarity of subsequently manufactured units to a flow-tested unit. Guidelines for conducting these tests are provided in Nonmandatory Appendix C.

6 SELECTION OF TEST METHOD

6.1 Test Measurement Methods

There are three types of measurement methods to consider. In order of increasing complexity, time, and cost of application, the methods are as follows:

(a) External Monitoring for Impacting. Impact detection from signals of accelerometers mounted on the exterior surfaces of the heat exchanger.

(b) Microphone Scan to Detect Impacting. Impact detection from signals of microphones installed at the tube ends.

(c) Direct Measurement of Tube Response. Measurement of tube response by transducers mounted on or adjacent to individual tubes.

6.1.1 Impacting is considered to include metal-to-metal contact between heat exchanger component pairs that has the potential to cause failure by wear. Component pairs include the following:

(a) adjacent tubes

(b) tubes and tube support plates

(c) auxiliary components, such as tie-rods and shell

6.1.2 The implementation of each of these measurement methods and guidelines for evaluation and interpretation of the results are provided in para. 7. The information obtained from each test method and their limitations are summarized.

(a) External Monitoring for Impacting. This method can do the following:

(1) detect the presence of severe tube vibration

(2) identify the threshold shell-side flow rate for impacting or determine that impacting does not occur for flow rates up to an established (design, operating, or test) flow rate limit

(3) provide a basis for establishing acceptable shell-side operating flow rate limits

(4) provide a criterion to determine the need for additional, more-detailed tests (e.g., microphone scan and/or direct measurement) or structural modifications

(5) in some cases, indicate the general location of impacting

(6) be limited as follows:

(a) Impacts may not be adequately detectable for determination of the flow rate at which impacting occurs by external accelerometers.

(b) The particular tubes or number of tubes that are impacting cannot be identified for further investigation of specific tubes.

(c) Quantitative information, as provided by the direct measurement method, is not obtained.

(b) Microphone Scan to Detect Impacting. This method can do the following:

(1) identify the threshold shell-side flow rate for impacting or determine that impacting does not occur for flow rates up to an established (design, operating, or test) flow rate limit

(2) identify the number and specific location of impacting tubes

(3) provide a basis for establishing an acceptable shell-side operating flow rate limit

(4) provide a basis for deciding if more direct measurements (using the method outlined in para. 7.1) or remedial actions are required

(5) identify specific tubes to be instrumented for direct measurement of tube response

(6) in some cases, provide an approximate indication of the relative severity of impacts of various tubes

(7) be limited as follows:

(a) This method cannot provide detailed quantitative data such as can be acquired by direct measurement with in-tube probes.

(b) The tube sheet must be accessible during testing.

(c) Direct Measurement of Tube Response. This method can provide vibration response amplitude and frequency information for specific tubes. It provides the best basis for assessing the potential for vibration-induced wear or fatigue.

The limitation of this method is that replacement of failed transducers and instrumentation of a large number of tubes is impractical for some configurations.

6.2 Bases for Selection

The direct measurement method is the only method that provides quantitative information on tube response. Information for both impacting and nonimpacting tube vibration for evaluation of tube fatigue and wear is obtained from the direct measurement method. Primary system steam generators and other heat exchangers considered to be critical to the operation of the plant shall be tested by the direct method.

The direct measurement method shall also be applied to heat exchangers, for which the following applies:

(a) Information to evaluate fatigue is required.

(b) Simpler measurements cannot be applied or interpreted.

For many heat exchangers, depending on the availability of pertinent supporting information, application of either or both of the impact detection methods, with no indication of impacting or with identification of a threshold flow rate for impacting that does not limit operation, may be considered adequate for vibration assessment.

If only external monitoring for impacting is used, adequate detection of impacts by externally mounted accelerometers shall be demonstrated for the heat exchanger under consideration. Impact detection is limited by impact amplitude, transmission path, and background noise level.

If impacting is detected within the operating limits of the shell-side flow rate by one of the impact detection methods, and the heat exchanger cannot be operated at the required reduced flow rate, further action is required. In such cases, structural modifications to increase the operating limit may be implemented or the direct measurement method may be applied to obtain further information on the source and location of the impacting to provide the basis for corrective action.

6.3 Precautions

Potentially damaging vibration can exist without generating metal-to-metal impact noise. The only way to guard against this possibility is to measure the tube vibration directly (e.g., with an in-tube vibration probe or other tube-mounted sensors). As indicated in para. 6.2, the direct measurement method shall be used for steam generators. In most cases, such an elaborate test will not be justified. However, for exchangers considered marginal in design, or highly critical to production or safety, such direct measurements or their equivalent shall be specified or available from other testing.

Experience has shown that detected impacting is not always related to tube vibration. As an example, tie-rods have been known to experience vibration and to impact with the shell. In such a case, reducing shell-side flow rate accordingly may not be appropriate if the situation can be easily corrected by strengthening the tie-rod. This is a concern when basing action on the results of only the external monitoring method.

External vibration surveys to assess externally generated sources of tube excitation such as floor vibration may, in conjunction with other tests, be useful in the determination or elimination of potential vibration sources. External surveys are discussed in Nonmandatory Appendix D.

7 TEST REQUIREMENTS

7.1 Direct Measurement of Tube Vibration

7.1.1 Introduction. Data from direct measurement of tube vibration are used to do the following:

(a) identify tubes or tube bundle regions having high vibration levels

(b) establish vibration levels as a function of flow rate

(c) detect the occurrence and variation of impacting of a tube or tubes with adjacent tubes or supports as a function of flow rate

(d) detect the onset of fluidelastic vibration

(e) identify vibration modes, and in some cases, the source of excitation

(f) provide a database for evaluation of fatigue and, if appropriate, for subsequent detailed wear evaluations

7.1.2 Tube Selection. The selection of tubes to be instrumented shall be based on the following:

(a) experience with similar units with consideration for design differences

(b) calculations, review of design information, and/or relevant model tests to determine tube locations that are anticipated to become unstable first as shell-side flow is increased

(c) tubes susceptible to high-level turbulence excitation

Where possible, an acoustic survey of the tube ends at the tube sheet (see para. 7.2) should be conducted to identify those tubes that are vibrating at amplitudes sufficiently large to cause impacting within the tube support plate hole or impacting with one another.

7.1.2.1 The determination of tubes that are likely to be more susceptible to fluidelastic instability and turbulence excitation, or both, shall include consideration of design features that can result in high velocity and/or turbulence regions. These include the following:

(a) the size and location of inlet nozzle

(b) the type and size of impingement plates

(c) baffle-type, cut, and spacing

(d) leakage paths between the shell and tube bundle, between the shell and baffles, and through tube-to-tube support plate clearances

7.1.2.2 In particular, regions of concern include the following:

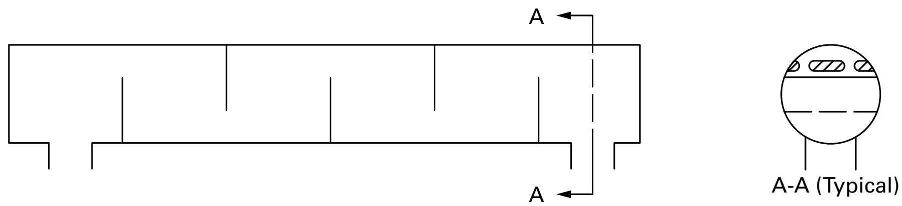
(a) tubes with long unsupported spans

(b) tube rows adjacent to a baffle cut

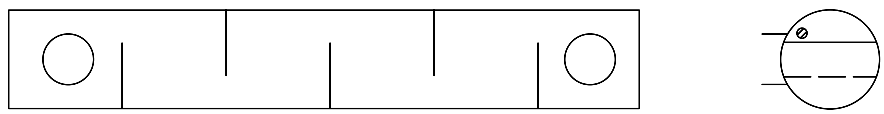
(c) tubes subjected to high local flow velocities or highly turbulent flow (e.g., tubes beneath the inlet nozzle)

For fluidelastic instability, information from detailed tube vibration flow tests of an industrial size shell-and-tube exchanger with segmental baffles are available (see Nonmandatory Appendix E). The results of these tests provide useful guidelines for the selection of tubes to be considered for instrumentation in a heat exchanger tube vibration assessment program. In particular, in Fig. 1, various tube bundle configurations which have been tested are shown together with bundle cross sections denoting the tube groupings, relative to locations of the baffle cuts, most susceptible to fluidelastic instability. An examination of the various cases shown in Fig. 1 reveals that the tubes with the longest spans exposed to high cross-flow velocities are most susceptible to vibration. If a particular tube bundle design is similar to one of the design cases shown in Fig. 1, it is recommended that tubes from the groupings indicated

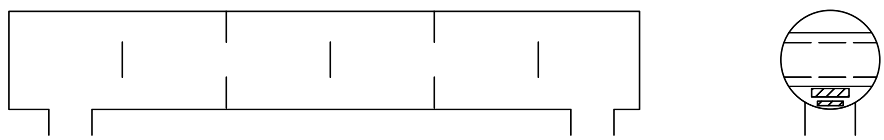
Fig. 1 Tube Bundle Configuration With Tube Groupings Most Susceptible to Fluidelastic Instability Denoted by Cross-Hatching



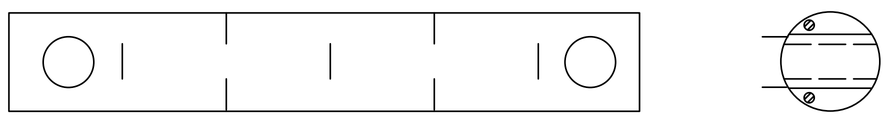
(a) Signal-Segmental, Transverse-Cut Baffles



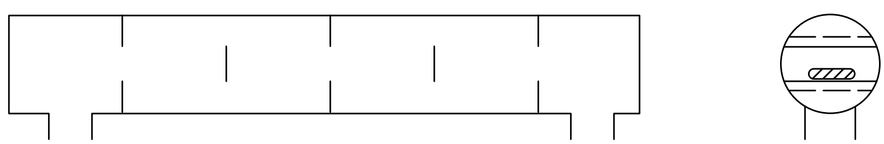
(b) Signal-Segmental, Parallel-Cut Baffles



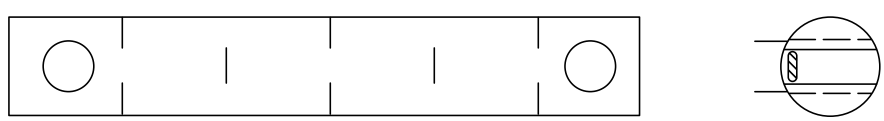
(c) Double-Segmental, Transverse-Cut Baffles



(d) Double-Segmental, Parallel-Cut Baffles



(e) Double-Segmental, Transverse-Cut Baffles



(f) Double-Segmental, Parallel-Cut Baffles

in the appropriate sketch in Fig. 1 be included in those chosen to be instrumented in a vibration monitoring program.

As a precaution, it should be noted that the heat exchanger flow tests have also shown that the tube rows directly exposed to inlet nozzle flow often experience significant excitation in a higher mode (e.g., fifth mode). In such cases, the vibration frequency is high and, while the displacement levels may be low, the velocity and/or acceleration levels can be high. Since tube wear at the tube-baffle interface is a concern, consideration should be given to instrumenting tubes in this region as well.

The primary tube locations that should be considered in the evaluation of vortex shedding are those locations that experience single-phase flow and are on the periphery of the bundle or adjacent to tube lanes or adjacent to other open areas.

7.1.3 Sensor Selection. Piezoelectric accelerometers are the most adaptable sensors because they are available in the miniature sizes and light weights required for heat exchanger testing. Piezoresistive accelerometers may be used for some tests. Piezoresistive accelerometers have a wide frequency response extending to zero frequency, but are typically limited to a maximum operating temperature of less than 200°F (93°C). Accelerometers are very suitable for the detection of metal-to-metal impacting. Strain gages and displacement transducers provide better low frequency (less than 10 Hz) information than do accelerometers.

(a) Accelerometers should be installed to measure vibration in two orthogonal directions in a plane that is perpendicular to the tube center line. The accelerometers should be positioned axially within a heat exchanger tube at a point that will result in sufficiently large acceleration signals for all modes of interest. Calculations should be used to determine this point. The calculation should be sufficiently detailed to account for multiple bending modes. When it is possible to do so, preliminary testing (moving an accelerometer axially within a tube) may be used to determine the optimal location or to verify calculations. Moving an accelerometer axially within a tube or use of multiple accelerometers is needed to determine the mode shapes of the tube vibration.

(1) Accelerometer selection shall be determined by the following factors:

(a) temperature, chemistry, radiation, and humidity (or pressure, if underwater)

(b) mounted natural frequencies

(c) sensitivity

(d) size

The effect of dissolved gases on sensor life shall be evaluated. Mounted natural frequencies should be at least a factor of three and preferably five greater than the highest modal frequency anticipated to be significant. The mounted natural frequencies shall be determined by calculation or by testing. The sensitivity of piezoelectric accelerometers should be greater than 10 pc/g. Miniature accelerometers, which may be required for some applications, are acceptable but may have sensitivities less than 10 pc/g. Low sensitivity could impair detection of low acceleration responses.

Biaxial accelerometers should be used. If two single axis accelerometers are used, the effects of the separation of the accelerometers should be considered. The accelerometers used shall be tested immediately prior to mounting to ensure operability and must be handled with care in the installation process.

(2) Cables frequently require more consideration than the accelerometer. The following requirements shall be met:

(a) Cables must be restrained and protected to prevent chafing, fretting, and noise generated by cable whip.

(b) Metal-sheated cables with a mineral oxide dielectric shall be used when temperatures exceed 500°F (260°C).

(c) Low-noise (treated) cables designed specifically for accelerometer applications shall be used.

(d) The cable length recommended by the signal conditioner manufacturer shall not be exceeded.

(3) Signal conditioners specifically designed for application with the test accelerometer shall be used. The following shall be considered in the selection of signal conditioning instrumentation:

(a) Remote charge converters or preamplifiers shall be used for piezoelectric accelerometers without internal amplifying electronics when cable runs exceed 100 ft (30 m) and should be considered when cable runs exceed 25 ft (7.6 m).

(b) The signal conditioner shall be used in accordance with the manufacturer's environmental ratings (remote monitoring location or test enclosures may be necessary).

(c) The signal conditioner shall have multiple gain ranges to allow maximum amplification without signal distortion.

(d) The signals should be filtered to minimize the effects of sensor resonance, except when impacts are to be detected.

(b) Strain gages may be used to supplement accelerometer data or in some cases may be more suitable for the necessary measurements. Additionally, strain gages can be used to determine axial preload or axial loading during thermal changes. In application, the following shall be considered:

(1) Strain gages shall be mounted in orthogonal pairs.

(2) Axial position shall be in the region of maximum bending, typically at the tube sheet.

(3) The axes of sensitivity of the gages shall be aligned with the tube axis.

(4) Three gages at a single axial location are required when axial and bending loads are measured. Four gages at a single cross-section are suggested for redundancy.

(a) Strain gage selection shall be determined by the following factors:

(1) temperature, chemistry, radiation, and humidity (or pressure, if underwater)

(2) sensitivity of the strain gage shall be suitable for measuring anticipated loads calculated by material, clearance, and span lengths

(b) Strain gages have been successfully cemented and welded inside heat exchanger tubes; however, mounting is an extremely delicate process and has been limited by tooling constraints to depths of approximately 24 in. (600 mm) from the tube end. Nonmandatory Appendix G contains information on strain gage mounting; as a minimum, the following shall be considered:

(1) Gage integrity shall be checked both before and after installation.

(2) The inner tube surface shall be prepared for strain gage installation.

(3) Gage position shall be accurately and completely documented.

(c) In addition, the following should be considered:

(1) redundant gages.

(2) thermocouples installed at the strain gage location so that the data can be properly temperature compensated.

(3) if mean strains are to be acquired, the gages, after mounting, should be subjected to at least one temperature cycle before test data are acquired.

(4) lead wire resistance and length of sheath should be measured so that the gage sensitivity may be known accurately.

(d) Strain gage cables are subject to damage and the following considerations and precautions shall be taken:

(1) During installation excessive bending or pulling of the strain gage cable shall be avoided.

(2) After installation cables shall be restrained to prevent chafing, fretting, or separation from the strain gage.

(3) Metal-sheathed cables with a mineral oxide dielectric shall be used when temperatures exceed 500°F (260°C) a breach in the outer sheath may result in cable failure).

(e) Strain gage amplifiers shall be used in accordance with the following:

(1) Each strain gage signal shall be individually connected to separate amplifiers (i.e., quarter bridges).

(2) Signal conditioners shall have provisions for balancing the gage and for sensitivity compensation.

(3) The signal conditioners shall have multiple gain ranges to prevent signal over or under range.

(4) The signal conditioner shall be used in accordance with the manufacturer's environmental ratings (remote monitoring location or test enclosures may be necessary).

(c) Noncontacting displacement transducers (or proximity probes) can be used to measure tube motion in the tube bundle periphery. Such transducers should be located at the point of maximum displacement as determined by calculation or measurement. Noncontacting displacement transducer selection shall be determined by the following:

(1) The transducer shall be rated for the temperature, chemistry, radiation, and humidity (or pressure, if underwater) condition to be encountered in testing.

(2) The transducer shall be calibrated (or compensation curves provided) for the tube (target) material.

(3) The transducer tip size shall be such that the eddy field is primarily unaffected by lateral tube motion and tube geometry.

(4) The transducer design shall be such that the eddy field is unaffected by tubes adjacent to bounding the target tube.

(5) The transducer design shall allow it to be used without modifying the heat exchanger tube properties being evaluated.

Two noncontacting displacement transducers separated by a known angle and targeted on the same tube should be used so that the orbital tube motion can be determined. The transducer shall be mounted so that heat exchanger components other than the targeted tube do not influence the measurement.

The transducer cable must be adequately restrained to prevent failure due to flow turbulence if encountered and to prevent heat exchanger damage if fluid flow is present.

The noncontacting transducer shall be powered and the signal conditioned as recommended by the manufacturer.

7.1.4 Data Acquisition. Details of data acquisition and reduction can be found in the reference in para. 3 (see para. 7.1.5). A summary of guidelines to be observed is provided here.

In comprehensive or complex tests, the data will be recorded for off-line analysis. If analog tape recorders are used, they shall be Inter-Range Instrumentation Group (IRIG) compatible, with a 1 in. (25.4 mm) tape recommended. Data shall be recorded in either FM (frequency-modulated) Wide-Band Group I or Intermediate Band. The recording speed shall be selected to ensure frequency response greater than the highest vibration mode to be observed or to ensure recording of impacts, depending on the purpose of the record. If digital records are used, the sampling rate should be set at least 2.3 times the maximum frequency of interest,

F_{max}. Also, the signal should be low-passed filtered before recording as per para. 7.1.5(d). For example, with a 48 dB/octave filter, the filter limit can be set between 1.1 F_{max} and F_{NY} [see para. 7.1.5(c)].

Prior to use, the tape recorder shall be checked for operability and calibrated. All pertinent information (signal recorded, data track designations, signal conditioner gain, tape speed, tape count, etc.) shall be completely and accurately entered in a comprehensive tape log; the tape log or a copy shall be stored inside the data tape container. If multiple data sets are recorded on a single tape, the tape should be advanced to leave a short unrecorded segment between data sets. A reference signal shall be recorded on each tape.

Signal gain changes should be avoided during recording sets. It is suggested that data recording be interrupted if a signal gain is changed. It is also suggested that a voice log be included on the tapes. The data being recorded shall be monitored on-line to add assurance of data quality and to meet precautions of para. 10.

The following guidelines are for determining the record time length:

(a) Determine the parameters for which the data are to be reduced. Examples are rms accelerations, velocities, displacements, strains, power spectral densities, cross-spectral densities, coherences, and peak values.

(b) Determine what channels of data are to be cross-correlated in the subsequent data analysis or in the follow-up diagnosis. The channels to be cross-correlated must either be multiplexed or simultaneously recorded on the same multichannel magnetic tape or otherwise time phased.

(c) Determine the frequency range of interest.

(d) Determine the frequency resolution in the subsequent data analysis. From the reference in para. 3, this can be estimated by

$$B_e \leq 2/\pi \ \xi_n f_n[(1 + p)^2 - 1]^{1/2} \tag{1}$$

where

B_e = frequency resolution
ξ_n = estimated damping ratio
f_n = estimated modal frequency
p = acceptable fractional deviation from the true value (e.g., $p = 0.2$)

As a rough guide, the bias error [see para. 3(b)] is acceptable if $p < 0.2$ so $p = 0.2$ is a good value for a first estimate of the frequency resolution.

Typical damping ratios in steam generator tube vary between 0.005 and 0.03. Therefore, $\xi = 0.005$ is a good conservative choice to estimate B_e. However, if in doubt, the resolution B_e should be varied to see if there is any significant change in the measured amplitude.

(e) Determine the record time length, T, required [see para. 3(b)] as follows:

$$T = \frac{1}{\epsilon^2 B_e} \tag{2}$$

where ϵ is the acceptable normalized error. In general, ϵ should be between 0.25 and 0.1. Equation (2) is true only if the bias error is acceptable [see para. 3(b)].

7.1.5 Data Reduction. Modern data reduction is almost universally done with specialized Fourier analyzers in which the analyst chooses some of the parameters while the Fourier analyzers' internal software sets the others. The procedure for data reduction depends on the particular Fourier analyzer used, but the following rules generally apply:

(a) Based on eq. (1), choose a suitable frequency resolution B_e.

(b) Choose a suitable block size N [see para. 3(b)]. In most Fourier analyzers, N is restricted to powers of 2 with an upper limit. Possible choices of N are 512, 1024, 2048, and so on.

(c) The frequency resolution B_e and the block size together determine the *theoretical* maximum frequency, or the Nyquist frequency $F_{NY} = 0.5\ NB_e$. The actual maximum frequency of interest, F_{max}, should be always below the Nyquist frequency. How much below depends on the antialiasing filter used [see para. 7.1.5(d)]. For a 48 dB/octave filter, e.g., F_{max} should be below F_{NY}. If this is not satisfied, either B_e or N should be adjusted. If a steeper filter is used, F_{max} can be closer to F_{NY}.

(d) Set the antialiasing filter slightly above F_{max} but below F_{NY}. For an analyzer with a 48 dB/octave filter, the cut-off point can be set between 1.1 F_{max} and F_{NY}. In some Fourier analyzers, the cut-off point is automatically set once F_{max} or F_{NY} is specified.

(e) Choose the number of averages n desired according to

$$n = \frac{1}{\epsilon^2}$$

where ϵ is the normalized error [see para. 3(b)]. Normally n should be between 16 and 100.

(f) The record time length per average is $1/B_e$. The total time length of record required is therefore n/B_e. This should be smaller than the total record time length recorded on tape.

7.1.6 Acceptance Guidelines and Follow-up Actions. Data that is acquired and reduced following the guidelines provided in paras. 7.1.4 and 7.1.5 will permit the determination of vibration parameters that are generally needed to determine tube vibration characteristics and to support estimation of whether or not the vibration levels are acceptable. The parameters usually include the following:

(a) true rms or peak values of tube displacement and vibration velocity as a function of flow rate

(b) the occurrence, relative severity, and frequency of impacting

Information to support the interpretation of the data is provided in Nonmandatory Appendix E.

Acceptance criteria shall be established by the Owner, generally with the support of the manufacturer or other experienced sources for the specific heat exchanger under assessment. Guidelines to assist the Owner in identification of vibration levels that require further action are provided in Nonmandatory Appendix F. In some cases, specific information may be available regarding acceptable vibration levels for the heat exchanger being assessed. One example of such information would be the availability of both wear data and vibration data for numerous tubes. These data may enable the establishment of a relationship between measured tube vibration levels and resulting tube wear for the heat exchanger under evaluation. When available, such information shall take precedence over the guidelines in Nonmandatory Appendix F.

7.2 Microphone Scan for Tube Impacting

7.2.1 Introduction. The microphone scan method for impacting provides a method that can quickly and positively determine which particular tubes are vibrating severely enough to be impacting, a basis for deciding if more direct measurements (using the method outlined in para. 7.1) or remedial action are required. In some cases, this method also provides an approximate indication of the relative severity of impact of various tubes. It cannot provide detailed quantitative data such as can be acquired by direct measurement with in-tube probes.

Since the tube sheet must be accessible, the tubes are not subjected to the effects of tube-side fluid mass and temperature. Therefore, effects related to the absence of tube-side fluid should be considered when interpreting results from the application of this method.

7.2.2 Specification of Microphones and Signal Conditioners

(a) Basic System. A basic system consists of a microphone, audio amplifier, and headset. The recommended microphone is a $\frac{1}{2}$ in. (12.7 mm) diameter size of the electret type, i.e., condenser microphone with built-in preamplifier. The amplifier should be a small battery-operated type, with plug-in jacks for microphone input and headset output and variable volume control. The earphones of the headset should be of a type that excludes extraneous sounds coming in from the room.

A recommended enhancement is to replace the amplifier with a small battery-powered tape recorder. This will provide the amplifier and volume control function and the capability to record microphone signals for the record and future reference.

(b) Filtering. The microphone signal will in general consist of two components arising from the impact. One is the low frequency mode of the air column in the tube. The other is high frequency structure-borne sound. Either component may be selected by filtering: low-pass filtering for the low frequency airborne sound and band-pass filtering (typically 2 kHz to 7 kHz) for the structure-borne sound.

For general use, switchable analog filter boxes employing Butterworth filters with sharp roll-off characteristics are recommended. For a specific application, fixed filters for the bandwidth of interest may be built.

(c) Chart Recording. For a quantitative permanent record, the microphone signals representing impact can be recorded on a strip chart recorder.

The frequency response of strip chart recorders is typically limited to below 50 Hz to 100 Hz. Microphone signals representing impact will normally contain higher frequencies. Therefore, the signals should be passed through full-wave rectification and peakhold detection circuits prior to recording. This process will convert a high frequency burst of multiple tube impacts to a single event on the chart.

(d) Frequency Analysis. Frequency spectrum analysis will be useful in some cases. For example, it can identify the low frequency and high frequency content in the signals to assist with filter setting. Frequency analysis can also assist in relating observed impact rates to known or predicted tube vibration frequencies.

Frequency analysis can be performed on any FFT analyzer (or personal computer, with appropriate software).

Most analyzers and software also have the capability to capture time-waveform signals. This feature can assist with analysis and interpretation of data. For example, the time-waveform will show the individual impacts of a multiple impact burst, whereas the chart recording method will lump them into a single event.

7.2.3 Data Acquisition. Application of the method requires the following:

(a) access to the tube sheet(s)

(b) an air environment on the tube side

(c) shell-side flow

The microphone must be either inserted into or placed over an open tube end. Since the sound of metal-to-metal contact is transmitted to the microphone via the air column in the tube, it is important that the air column be sealed from the external environment at the opposite tube end using a suitable rubber plug or boot.

7.2.3.1 In application, the shell-side flow rate is varied (typically increased in steps) and the tube sheet (tube ends) is scanned with the microphone. Data acquisition methods include the following:

(a) audio monitoring using a headset (the quickest and simplest method)

(b) recording the time signals on tape (quantitative data are obtained for subsequent data reduction and analysis)

Audio monitoring is typically conducted first. Results from the audio survey are used to identify tubes from which more detailed, quantitative data are required.

7.2.4 Data Reduction and Interpretation. By carefully listening to sounds from the various tubes (audio monitoring with headset), it is possible to do the following:

(a) differentiate between an impacting and nonimpacting tube

(b) identify the tube groupings, or zones, that are experiencing impacting

(c) determine the threshold flow rate for impacting

7.2.4.1 Time histories are processed using techniques that involve the following:

(a) frequency spectral analysis

(b) filtering

(c) amplitude metering

(d) chart recording

7.2.4.2 Impacting is identified, in general, as a sudden burst followed by an exponential decay of the signal amplitude.

(a) Spectrum analysis provides the frequency content of the impact bursts. (Normally this will fall in the range of 0 kHz to 10 kHz, but extending the range to 20 kHz may be useful in some cases.)

(b) A quantitative indication of intensity is obtained by rms, or "peak" metering of the time signal. (Normally the impact burst is the dominant part of the total signal and the raw signal can be metered. Where extraneous components are present, filtering should be used to select only the impacting components for metering.)

(c) Limited experience indicates that amplitude of the microphone signal can be correlated with impact acceleration or directly measured with an in-tube probe. (This relationship has not been fully developed and generalized and, therefore, should be used as a guide and confirmed in any specific case.)

Case histories illustrating the use of tube sheet microphones are included in Nonmandatory Appendix E.

7.2.5 Impact Detection Guidelines and Remedial Actions. In all but exceptional cases, severe tube vibration can be detected by microphone scanning of the tube ends. Impact detection guidelines, as regards the character of the noise as a function of flow rate and vibration severity, are the same as those given in para. 7.3.6 for external monitoring for impacting. The main result of the microphone scanning is the identification of specific tubes for direct vibration measurement (see para. 7.1) or remedial modifications (see para. 7.3.6).

7.3 External Monitoring for Impacting

7.3.1 Introduction. Very often the internals of an operational heat exchanger are not accessible without disassembly. Under this circumstance, external monitoring is the only way to check for severe tube vibration. To pinpoint the location and severity of the impacting, external monitoring can range from simply listening with the unaided ear to an externally shell-mounted accelerometer with an amplifier and a headset to multiple shell-mounted accelerometers with arrays of amplifiers and recorders for offsite correlation and wave analysis. Fundamentals of acquiring and reducing random vibration data are discussed in paras. 7.1.4 and 7.1.5.

7.3.2 Transducer Locations. Impacting has been successfully detected by transducers mounted on the heat exchanger shell adjacent to baffle edges, at locations of the tube sheet where there is direct mechanical contact to the shell, or at locations where local flow velocity is high and shell-to-tube (or tie-rod) clearance is minimum. Further information that will assist in sensor location may be obtained from the naked ear, from a hand-held accelerometer survey, or from design information that indicates the tube(s) and span(s) most susceptible to flow-induced vibration.

7.3.3 Accelerometer Selection. Accelerometers are considered to be the best transducer for detecting metal-to-metal impacts. The following factors shall be considered in choosing an accelerometer for external monitoring of impacting:

(a) sensitivity

(b) frequency range

Accelerometer sensitivity must be high; often the energy release during impacting is very small. The frequency range should be sensitive to at least 10 kHz to measure higher mode response frequencies.

7.3.4 Accelerometer Mounting. Accelerometer mounting is very important to the quality of signal recorded. For detecting metal-to-metal impacts, neither magnetic nor strap mounting is recommended as these mountings are not rigid enough to ensure quality high frequency signals. While the thread-mounted method is the best, it may not be necessary for qualitative detection of impacting. For this purpose, the best compromise between efficiency and quality is either cement mounting or epoxy mounting.

7.3.5 Accelerometer Cables and Signal Conditioning. The following shall be considered regarding accelerometer cables and in the selection of signal conditioning instrumentation:

(a) Low-noise (treated) cables designed specifically for accelerometer applications shall be used.

(b) The cable length recommended by the signal conditioner manufacturer shall not be exceeded.

(c) Remote charge converters or preamplifiers shall be used for piezoelectric accelerometers without internal amplifying electronics when cable runs exceed 100 ft

(30 m) and should be considered when cable runs exceed 25 ft (7.6 m).

(d) The signal conditioner shall be used in accordance with the manufacturer's environmental ratings (remote monitoring location or test enclosures may be necessary).

(e) The signal conditioner shall have multiple gain ranges to prevent signal over or under range.

(f) The signals should be filtered to minimize the effects of sensor resonance.

7.3.6 Impact Detection Guidelines and Remedial Actions. Minor vibrations that have characteristic sounds of light impacting often involve only one or two tubes and are intermittent rather than sustained. Severe vibrations, such as those from flow-excited instability, will be loud, sustained, and usually involve numerous tubes, producing a general clatter.

In some cases, initial identification of impacting may be more readily accomplished at flow rates that produce bursts of impacting than at flow rates that result in sustained impacting.

Follow-up actions when impacting is detected include one or more of the following:

(a) If a clear threshold is detected, limit operation to a flow rate that is below the threshold.

(b) Modify the equipment to eliminate expected causes of excessive vibration based on available structural and design information or data from additional testing.

(c) Identify impacting tubes by a microphone scan of the tube sheet (see para. 7.2). Remove these tubes from service by plugging and stabilization.

(d) Obtain direct tube vibration data to permit more specific evaluation of the impacts (see para. 7.1).

8 TEST CONDITIONS

Various test conditions may have to be considered and depend on the specifics of each case. Results of a test may dictate conditions for follow-up tests.

8.1 Shell-Side Flow Rate

The test should generally cover a range of flow rates. This test procedure will allow identification of tube vibrations that only occur over a particular range of shell- side flow rate. Additionally, operational requirements of the heat exchanger may specify its operation at reduced flow for extended periods before full flow is reached, and this condition shall be tested for excessive tube vibration.

Data shall be taken for the following conditions:

(a) shell-side flow rate incrementally increased 5% to 10% with associated steady states reached between 25% and 100% of maximum shell-side flow rate. Flow sweeps may be used to identify flow rates at which significant changes in signal levels occur. Smaller increments of flow change around these apparent flow rates shall be performed to adequately determine the flow rates at which changes in signal level occur and associated vibrational signal magnitude.

(b) shell-side flow rate at 100% flow and any flow rate condition associated with planned extended heat exchanger operation. These conditions are considered the most important steady-state operating conditions that affect tube integrity.

(c) shell-side flow rate of at least 110% of design flow unless prohibited by the manufacturer or precluded by operating constraints. This overflow condition will provide some insurance and documentation of margin against any severe tube vibration instability.

(d) the maximum flow rate if greater than the operating steady-state value at full power.

Caution is noted on maintaining a given flow rate at a condition that indicates significant tube vibration. In some cases, fluidelastically induced tube excitation can compromise tube integrity within a short period of time.

8.2 Rough Process Conditions

Shell-side flow rate is the primary variable in tube vibration. However, other process circuit parameters, such as fluid temperature, back pressure, flow imbalance or unsteadiness, off-design rough operation and valve settings, can be important. An effort shall be made to ensure that such conditions are covered by the test matrix.

9 DOCUMENTATION

The flow conditions and all significant process parameters for the test shall be documented. Direct measurements of shell-side flow and/or pressure drop across the shell are preferred. Where these are not available, the use of pump head characteristics and valve positions should be validated and carefully documented. Flow rates may be calculated using some of these characteristics.

The evaluation of tube vibration levels in accordance with para. 10(c) shall be documented.

10 PRECAUTIONS

The following precautions shall be observed during the planning and execution of heat exchanger vibration measurement programs:

(a) Adequate precautions shall be taken to ensure the safety of personnel associated with the test or near the equipment during all phases of the program.

(b) Instrumentation and other test hardware installation and removal shall be in accordance with all applicable codes and standards for the equipment being tested.

(c) Tube vibration levels shall be reviewed at each flow rate plateau. Acceptability should be determined before proceeding to higher flow rates.

PART 11
NONMANDATORY APPENDIX A
Causes of Vibration

A-1 DISCUSSION

In general, tubes in a heat exchanger will vibrate at all flow rates. However, it is the large-amplitude motion associated with fluidelastic instability that is usually of most concern. This large motion has the potential to lead to early failure of the equipment. The small-amplitude motion associated with subcritical flow rates is generally acceptable. However, there are situations in which vortex shedding or high turbulence levels in combination with adverse or inadequate support conditions or support deterioration can cause unacceptable tube vibration.

Acoustic noise has also been a problem encountered in heat exchangers. For the most part, the problems that have been reported are for larger exchangers with a gas or two-phase fluid flowing on the shell side. The resulting intense sound level generated in the area of the heat exchanger is usually intolerable and the potential for acoustic excitation of the heat exchanger walls must be considered. Tube bundle vibration is generally not a concern except where there is a triple coincidence among the fluid excitation, acoustic vibration, and tube vibration frequencies.

Significant progress has been made in understanding the fluid excitation mechanisms and in the development of related design guidelines. For the most part, the studies and design methodology are based on idealized laboratory tests involving single-span tube arrays subjected to uniform cross-flow. However, application to an actual heat exchanger is not at all straightforward because of the complex flow distribution in shell and tube exchangers and the complexities associated with the tube support arrangement, such as tube support plate clearances. Inlet/outlet nozzle sizes, impingement plates, inlet/outlet flow distributors, baffle size and spacing, and leakage paths, both between shell and tube bundle and between tubes and baffle plate holes, will all affect the flow velocity distribution. Tube vibrational characteristics (e.g., natural frequencies, mode shapes, damping, and degree of nonlinearity in response) will be determined by baffle spacing, tube-to-baffle-hole clearance, baffle plate alignment, tube straightness, mechanical fit-up of the tubes and tube axial loads both initially and under operating conditions, tube layout (i.e., pattern and pitch), and the properties of the shell-side fluid.

In addition to excitation by shell-side flow, there is the possibility for structural-borne excitation to contribute to the vibration of tube bundles. Excitation sources would include floor vibration, as might be caused by rotating machinery. Transmission paths would include heat exchanger support structures and connecting piping. In general, it is difficult to predict such vibration sources and related energy transmission *a priori*, as they will be site specific.

The dynamic behavior of a typical industrial size heat exchanger tube bundle is reported in the references in paras. A-2(a) through (f). In general, the tube vibration behavior as the shell-side flow rate is increased can be summarized as follows: at low flow rates, small-amplitude tube motions occur, typically random in nature; these increase to cause rattling within the baffle (support) plate hole as the flow rate is increased; large-amplitude motion and typically tube-to-tube and/or tube-to-baffle plate impacting results when the flow rate becomes sufficiently high. This behavior is shown in Fig. A-1, where one can see the small-amplitude response at low flow rates and can identify a threshold flow rate [in this case, ~1,950 gpm (442.8 m^3/hr)] above which large-amplitude tube vibration and tube impacting occurs.

Figure A-2 shows typical power spectral density (PSD) representations of the acceleration response of a tube for a range of flow rates. For this example, the threshold or critical flow rate occurs in the range 2,200 gpm to 2,400 gpm (499.6 m^3/hr to 545.0 m^3/hr). It is interesting to note that at subcritical (below the threshold flow rate for large-amplitude vibration) flow rates, the tube response includes contributions from a band of frequencies, while above the critical flow rate the tube response is at a single frequency involving a particular mode.

The three mechanisms generally regarded as responsible for the vibration of heat exchanger tubes are turbulent buffeting, vortex shedding, and fluid-elastic instability.

Turbulent buffeting is present at all flow rates and includes random pressure fluctuations associated with the turbulent boundary layer, as well as turbulent wake flows from upstream tubes or other flow path obstructions or irregularities such as the inlet. In general, it is random in nature and can be generally considered responsible for the low level tube vibration and rattling

Fig. A-1 Rms Acceleration Versus Flow Rate From Three Typical Tubes

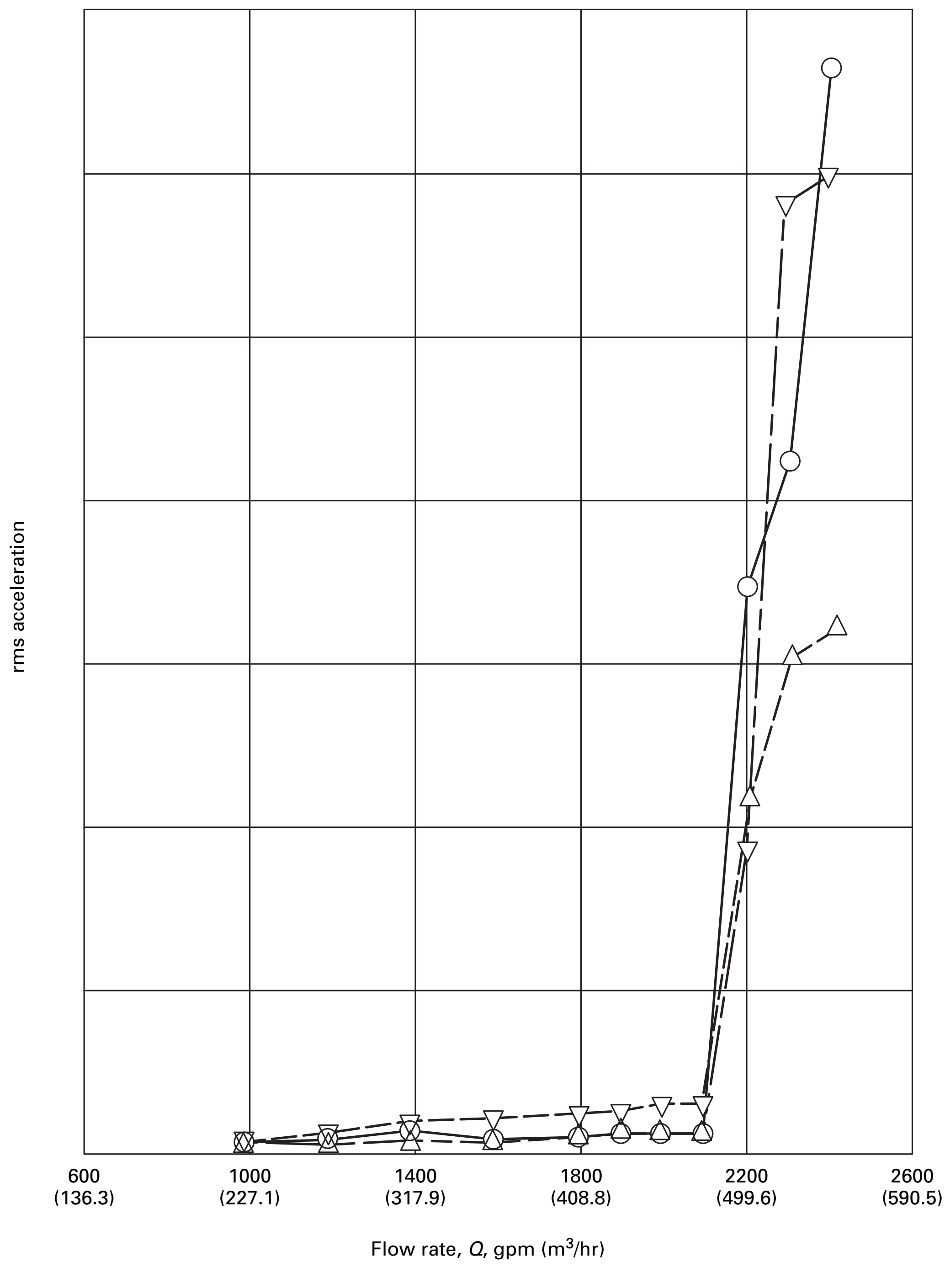
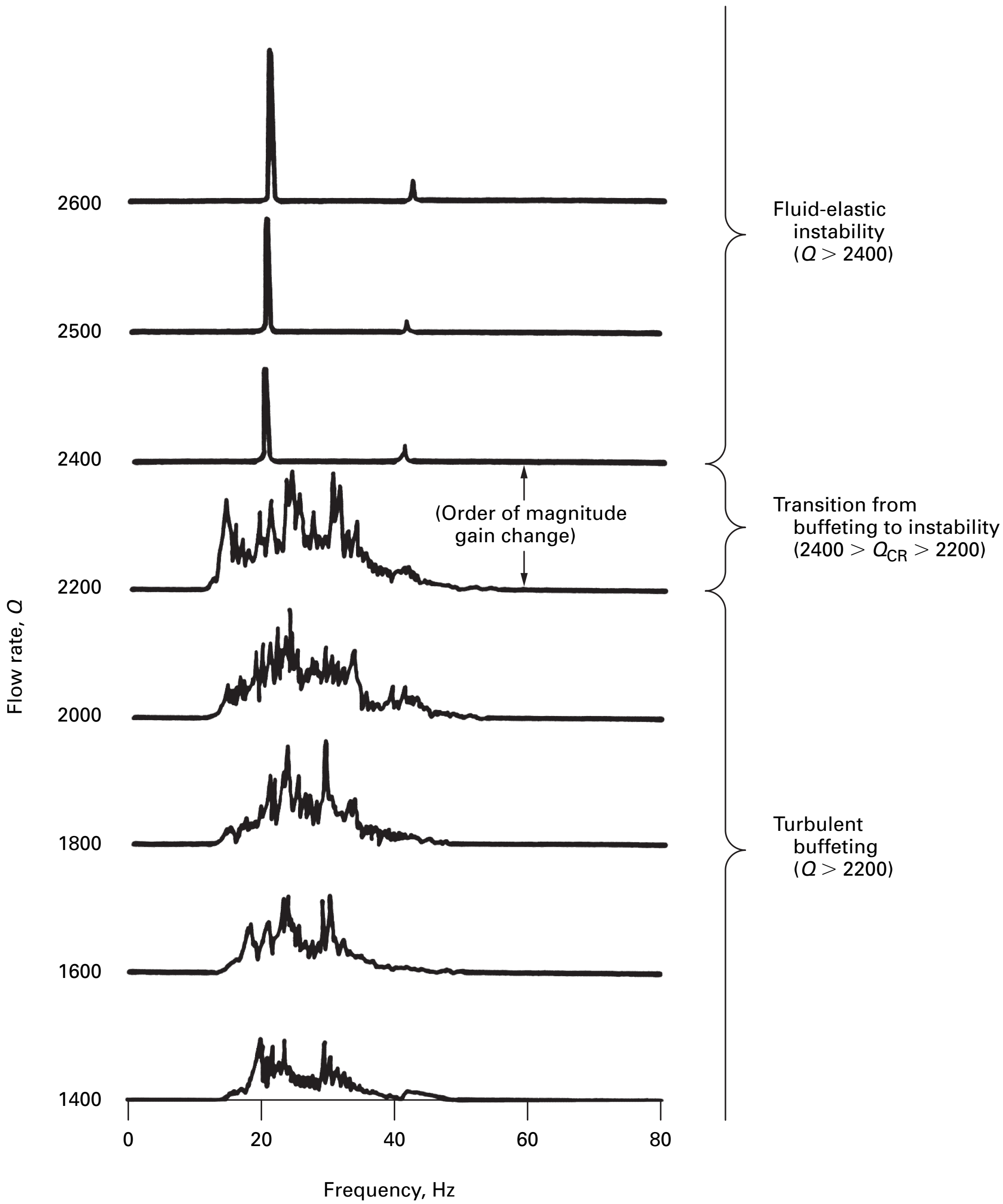


Fig. A-2 Tube Response PSDs for Various Shell-Side Flow Rates (Ordinate Not to Scale)



experienced at subcritical flow rates. See Figs. A-1 and A-2 for examples of response behavior. In some cases, inlet turbulence can generate significant tube motion. Analysis methods for buffeting response are based on random vibration theory or measured excitation forces [see para. A-2(g)].

Vortex shedding, while an important mechanism for single cylinders exposed to cross-flow, is generally not important for a tube bundle unless the tube spacing is large (pitch-to-diameter ratio, $P/d > 2.0$). For most industrial heat exchangers the spacing is relatively small with typical values of P/d ranging from 1.25 to 1.40.

The mechanism generally of most concern is fluidelastic instability, as it leads to large-amplitude motion that persists once the threshold flow rate is exceeded. Fluidelastic instability, of the type responsible for tube bundle vibration, has been the subject of a considerable number of investigations, both experimental and theoretical [see, for example, paras. A-2(h) and A-2(i)].

While significant progress is being made in developing an understanding of fluidelastic instability phenomena in tube bundles, the state-of-the-art has not yet progressed to the point that would allow calculation of the fluid dynamic force coefficients required for an analytical prediction of the threshold flow velocity for a particular tube bundle. Consequently, in design, it is still necessary to rely on experimental data obtained from laboratory tests. In a design guide, available experimental data have been assembled and stability diagrams plotted in the form of dimensionless parameters [see para. A-2(j)]. However, application of the stability diagrams, as well as the equation forms of the stability criteria, to the design evaluation of an actual heat exchanger is not straightforward. In particular, application is complicated by the complexities of the flow distribution within the heat exchanger, not to mention inherent uncertainties and nonlinearities related to the degree of tube support provided by the baffles that will directly affect tube vibrational characteristics.

A-2 REFERENCES

The following is a list of publications referenced in this Appendix.

H. Halle and M. W. Wambsganss, "Tube Vibration in Industrial Size Test Heat Exchanger," ANL Technical Memorandum ANL-CT-80-18 (March 1980)

H. Halle, J. M. Chenoweth, and M. W. Wambsganss, "Flow-Induced Tube Vibration Tests of Typical Industrial Heat Exchanger Configurations," ASME 81-DET-37, 8th ASME Vibrations Conference (Hartford, CT, September 1981)

M. W. Wambsganss, H. Halle, and W. P. Lawrence, "Tube Vibration in Industrial Size Test Heat Exchanger (30° Triangular Layout—6 Crosspass Configuration)," ANL Technical Memorandum ANL-CT-81-42 (October 1981)

H. Halle and M. W. Wambsganss, "Tube Vibration in Industrial Size Test Heat Exchanger (90° Square Layout)," ANL Report ANL-83-10 (February 1983)

H. Halle, J. M. Chenoweth, and M. W. Wambsganss; M. P. Paidoussis, J. M. Chenoweth, and M. D. Bernstein, eds.; "Flow-Induced Tube Vibration Thresholds in Heat Exchangers from Shellside Water Tests," ASME Symposium on Flow-Induced Vibration; Vol. 3, Vibration in Heat Exchangers (New York, NY, 1984): 17–32

H. Halle, J. M. Chenoweth, and M. W. Wambsganss, "Tube Vibration in Industrial Size Heat Exchanger (22 Additional Configurations)," ANL Report ANL-85-66 (December 1985)

T. M. Frick, "Summary of Preheat Steam Generator Experiences and the Basis for a Turbulent Force Modeling Procedure," Transactions of the 8th International Conference on Structural Mechanics in Reactor Technology, Vol. D, Paper D3/2 (1985): 283–287

M. P. Paidoussis, "Flow-Induced Instabilities of Cylindrical Structures," ASME Applied Mechanics Review, Vol. 40 (2) (1987): 163–175

S. S. Chen, "Flow-Induced Vibration of Circular Cylindrical Structures," Hemisphere Publishing Corp. (Washington, 1987)

S. S. Chen, "Guidelines for the Instability Flow Velocity of Tube Arrays in Crossflow," ASME Journal of Sound and Vibration, Vol. 93 (1984): 439–455

PART 11
NONMANDATORY APPENDIX B
Methods for Comparative Evaluation of Fluidelastic and Turbulence-Induced Vibration

B-1 INTRODUCTION

This Appendix gives simplified methods to assess the need for detailed testing. Very often a particular design of proven field performance is modified to suit a specific need or as a result of field repair or operation. However, if the modification is sufficiently minor that the integrity of the "new" design can be established by comparative analyses with a heat exchanger of proven field performance as the reference, detailed tests may not be necessary. Because the following methods are highly simplified, they are conservative. Failure to meet the criteria, therefore, does not necessarily mean that the design is inadequate. It simply means that either testing or a more exact method of analysis, probably with vendor-specific data as input, is necessary.

B-2 NOMENCLATURE

B = fluidelastic stability constant, dimensionless
C = mode shape weighting factor, dimensionless
C_r = random lift coefficient, $\sec^{-1/2}$
D = tube outside diameter, in. (m)
E = Young's modulus, psi ($N \cdot m^2$)
f_j = tube modal frequency, Hz
i = span index
j = modal index
L = characteristic length, in. (m)
l = moment of inertia, $in.^4$ (m^4)
= tube overall length, in. (m)
l_i = length of span i of the tube, in. (m)
m = total mass (structural, fluid, and virtual) per unit tube length, lb $\sec^2/in.^4$ (kg/m)
m_o = reference (usually an averaged value) total mass per unit length, lb $\sec^2/in.^4$ (kg/m)
M_j = modal generalized (total) mass, unit depends on mode shape normalization
Q = shell-side volumetric flow rate, $in.^3$/sec (m^3/s)
U_e = equivalent mode shape weighted cross-flow velocity, in./sec (m/s)
U_m = mean cross-flow gap velocity, in./sec (m/s)
$U(x)$ = cross-flow gap velocity, in./sec (m/s)
y = tube vibration amplitude, in. (m)
$Y(x)$ = cross-flow velocity distribution function, dimensionless
ξ_j = modal equivalent viscous damping ratio, dimensionless
ϕ_j = tube vibration mode shape, unit depends on normalization convention
ρ = fluid mass density, lb $\sec^2/in.^4$ (kg/m^3)
ρ_o = reference (usually an averaged value) fluid mass density, lb $\sec^2/in.^4$ (kg/m^3)

B-3 FLUIDELASTIC INSTABILITY

A parameter grouping can be defined and used as "figure of merit" to assess the design acceptability from the standpoint of fluidelastic instability and for the determination of the need for testing or redesign. The parameter grouping applies to designs that have single-phase flow on the shell side and are geometrically similar to a reference design that has been determined acceptable via testing or successful operation, or both, but are subject to differences in service conditions (e.g., flow rate and temperature), shell-side fluid flow, or tube material.

A fluidelastic stability margin can be defined as

$$R_j = U_c/U_{ej} \tag{B-1}$$

where U_c is the critical velocity for fluidelastic instability given by

$$U_c = Bf_jD(2\pi\xi_j m_o/\rho_0 D^2)^{1/2} \tag{B-2}$$

and U_{ej} is an equivalent mode weighted cross-flow velocity for mode j defined as

$$U_{ej} = \left\{ \frac{(1/\rho_o)\int_o^l \rho(x)U^2(x)\phi_j^2(x)\,dx}{(1/m_o)\int_o^l m(x)\phi_j^2(x)\,dx} \right\}^{1/2} \tag{B-3}$$

Equations (B-1) through (B-3) together indicate that a given heat exchanger tube bundle will experience fluidelastic instability if $R_j < 1.0$

Furthermore, the larger the R_j above unity, the larger the fluidelastic stability margin. Equation (B-1) can be interpreted as the stability criterion. Note that in eq. (B-1) the reference mass densities m_o and ρ_0 cancel out. In eq. (B-3), $U(x)$ can be represented as

$$U(x) = U_m Y(x) \tag{B-4}$$

Substituting eq. (B-4) into eq. (B-3) yields

$$U_{ei} = C_j U_m \tag{B-5}$$

where C_j is a mode weighting factor defined as

$$C_j = \left\{ \frac{(1/\rho_o) \int_o^l \rho(x) Y^2(x) \phi_j^2(x)\, dx}{(1/m_o) \int_o^l m(x) \phi_j^2(x)\, dx} \right\}^{1/2} \tag{B-6}$$

For geometrically similar heat exchangers, in which the fluid density and total tube mass is also uniform along the length of the tube, C_j can be assumed to be the same and the following proportionalities can be used:

$$f_j^2 \alpha EI/L^4 m \tag{B-7}$$

$$U_m \alpha Q/L^2 \tag{B-8}$$

Equations (B-1), (B-2), and (B-5) through (B-8) together give

$$R_j \alpha K = (EI\zeta/\rho Q^2)^{1/2} \tag{B-9}$$

where it has further been assumed that $\xi_j = \xi_i$, i.e., for a given heat exchanger the equivalent viscous damping ratio is the same for all modes.

The parameter grouping K, defined by eq. (B-9), can be used to assess a geometrically similar design by carrying out the following procedure:

(a) Calculate K for the reference design and designate it K'.

(b) Calculate K for the design under consideration.

(c) Calculate the ratio $S = K/K'$.

(d) If $S > 1.0$, testing is not required.

(e) If $S < 1.0$ and the reference design has been tested and known to have been operating close to the critical flow, the design is unacceptable.

(f) If $S < 1.0$ and the reference design is operating below the critical flow, testing is required.

B-4 SIMPLIFIED METHOD FOR ESTIMATING TURBULENCE-INDUCED VIBRATION IN A SIMILAR DESIGN

For designs with single-phase flow on the shell side that are similar to a reference design that has been determined acceptable via testing or successful operation, or both, but are subject to differences in operating conditions (e.g., flow rate and temperature) and tube-to-support plate clearances (due to chemical deposit or cleaning) with resulting differences in flow velocities, fluid densities, tube axial load (and thus tube natural frequencies), and damping ratios, the following simplified equation can be used to estimate the ratio of the turbulence-induced vibration amplitude of the "new" design to that of the reference design:

$$\frac{y}{y_R} = \sum_j \frac{\rho Q^2 C_r(f_j)}{\rho_R Q_R^2 C_r(f_{Rj})} \left\{ \frac{M_{Rj}^2 f_{Rj}^3 \zeta_{Rj}^3}{M_j^2 f^3 \zeta_l} \right\}^{1/2} \tag{B-10}$$

where the summation is over all the important modes and subscript R denotes the reference design. $C_r(f)$ is the random turbulence excitation coefficient at frequency f. From Pettigrew's data [see para. B-5(a)], an upper bound estimate for the turbulence excitation coefficient can be derived (see Table B-1).

NOTE: As defined in eq. (B-10) and in para. B-5(a), C_r has dimensions of sec$^{-1/2}$.

Table B-1 Upper Bound Estimate of the Random Turbulence Excitation Coefficient for Tube Bundle

Frequency, Hz	C_r, sec$^{-1/2}$
0–40	0.025
50	0.017
60	0.012
70	0.0083
80	0.0058
90	0.0040
100	0.0028
110	0.0019
120	0.0013
140	0.00092
160	0.00031
180	0.00015
200	0.000071

If $y < y_R$ by a margin large enough to accommodate the uncertainties in the parameters that determine the responses, then testing is not necessary.

For designs that are geometrically similar but not identical to a reference design, a more detailed analysis is necessary to alleviate testing [see para. B-5(b)]. Following the reference in para. B-5(c), the upper bound mean square response of a multispan tube bundle is given by

$$y^2(x) = \sum_j \sum_i \frac{l_i G_\rho^{(i)}(f_j) \phi_j^2(x)}{64\pi^3 M_j^2 f_j^3 \zeta_j} \tag{B-11}$$

where

$$G_\rho^{(i)}(f) = (D/2)^2 C_r^2(f) \int_o^{l_i} [\rho(x) U^2(x)]^2 \phi_j^2(x)\, dx \tag{B-12}$$

is the mode shaped, weighted, span-averaged turbulence pressure power spectral density and the summation is over all the spans i and all the important modes

j contributing to the response. Extensive testing is not necessary if application of eqs. (B-11) and (B-12) to both the new and the reference designs shows that

(a) the amplitudes of response and the resulting stresses are well within the allowable limits for wear and fatigue for both the new and the reference designs.

(b) the computed vibration amplitude and stress for the new design are equal to or less than those of the reference design.

Equation (B-11) is a very conservative estimate of the turbulence-induced vibration amplitude of a multispan tube bundle and bounds the lock-in vortex-induced vibration amplitude. Failure to meet the above requirements, therefore, does not necessarily mean that the design is not acceptable, or even that detailed tests must be done. It just means that a more detailed analysis [see the reference in para. B-5(b)], possibly backed up by more refined vendor-input data, is necessary to alleviate detailed tests.

B-5 REFERENCES

The following is a list of publications referenced in this Appendix.

M. J. Pettigrew and D. J. Gorman, P. Y. Chen, ed., "Vibration of Heat Exchanger Tube Bundles in Liquid and Two-Phase Cross Flow," Flow-Induced Vibration Design Guidelines, ASME PVP-Vol. 52 (1981)

M. K. Au-Yang and B. Brenneman, "Flow-Induced Vibration Analysis of an Integral Economizer Once-Through Steam Generator," ASME Journal of Pressure Vessel Technology, Vol. III (1989): 501–506

M. K. Au-Yang, "Turbulent Buffeting of a Multi-Span Tube Bundle," ASME Journal of Vibration, Stress, Acoustics, and Reliability in Design, Vol. 108 (1986): 150–154

PART 11
NONMANDATORY APPENDIX C
Test Guidelines for Dynamic Characterization of Tubes

C-1 TUBE MECHANICAL VIBRATION CHARACTERISTICS

Test guidelines are outlined below for the following:

(a) modal frequency determination

(b) mode shape characterization

(c) modal damping estimates

In using the results, consideration should be given to the effects of fluid if the test is performed in air and also to motion of the surrounding tubes.

C-2 MODAL FREQUENCIES AND DAMPING DETERMINATION

The following is the test procedure:

(a) Identify the location of each tube selected for testing. A minimum of three tubes is necessary to give reasonable statistical confidence.

(b) Install one or more biaxial accelerometers in each of the tubes selected. Usually some specially developed tools are necessary to install the accelerometers.

(c) Connect the accelerometer to the signal conditioners, tape recorders, and online spectrum analyzer.

(d) Set the appropriate frequency range of the spectrum analyzer and adjust the analyzer to capture a single transient. For most applications, an upper frequency limit of 500 Hz is suitable.

(e) Impulsively excite the tubes by hammer impacting the tubes directly or by impacting the exterior of the shell.

(f) Determine the tube modal frequencies from the spectrum peaks.

(g) Determine the modal damping ratio by the logarithmic decay method. If X_n and X_{n+1} are the amplitudes of two consecutive cycles, then

$$\xi = \frac{C}{C_C} = \frac{1}{2\pi} \log_e \frac{x_n}{X_{n+1}}$$

where C is the damping coefficient and C_C is the critical damping ratio. In practice, plotting of this function on semilog paper over several cycles is necessary to obtain reliable results.

(h) Repeat the above procedure for each of the tubes selected.

(i) Using statistical analysis technique, check for normality, mean, and standard deviation of the modal frequencies and damping ratios determined from the ensemble of tubes selected for testing.

C-3 MODE SHAPE CHARACTERIZATION

The following are the test procedures:

(a) Install a reference biaxial accelerometer, with its sensitive axes perpendicular to the tube, approximately $\frac{1}{8}$ span from the support plate.

(b) Install a movable biaxial accelerometer in the tube with its sensitive axes perpendicular to the tube.

(c) Connect both accelerometers to the signal conditioner, spectrum analyzer, and tape recorder.

(d) Excite the tubes as outlined in para. C-2. Record the tube responses at the locations of both the reference and movable accelerometers.

(e) Move the movable accelerometer to another location and repeat the procedure.

(f) Determine the amplitude ratio and phase relative to the reference accelerometer at each of the movable accelerometer locations.

(g) Determine the mode shape of the tested tube span by curve fitting of the data points.

PART 11
NONMANDATORY APPENDIX D
External Vibration Surveys

D-1 INTRODUCTION

The purposes of an external survey are as follows:

(a) to assess the likelihood of significant tube vibration due to motion of tube supports by vibration transmitted from supporting structures, piping, valves, or machinery.

(b) to assist in the determination of causes of tube vibration or wear detected by other means. A walkaround inspection should be made of the tube sheets, shell and supporting structure, and nearby connected piping to identify unusually large vibrations.

D-2 MEASUREMENT LOCATIONS

Vibration at the tube sheets and shell should be measured and recorded. If determined to be excessive, vibration at other locations on structure, piping, valves, and the like should be measured and recorded for diagnostic purposes.

D-3 ACCEPTANCE GUIDELINES AND RECOMMENDED FOLLOW-UP

Acceptance levels should be established by the Owner. If system-specific information is not available, reference can be made to various standards for machinery, piping, and structural vibration (see Nonmandatory Appendix F). If the survey indicates significant levels, the vibration data should be examined for frequency content near the natural frequencies of the tubes. If such content is present, the effects should be determined by analysis or additional measurements. Determination of tube natural frequencies should consider the potential for ineffective support at one or more tube supports.

PART 11
NONMANDATORY APPENDIX E
Detection Methods and Data Interpretation

E-1 INTRODUCTION

The threshold flow velocity corresponding to the onset of instability is not always easy to determine in laboratory tests and is even more difficult to establish in the case of real heat exchange equipment. The situation involving a real heat exchanger is complicated by the large number of tubes in the bundle, several possible tube support arrangements, and the complex (nonuniform) flow distribution, all of which will result in specific groups of tubes experiencing instability at a different flow rate than other groups of tubes.

The methods and data described in this Appendix are provided to assist the user in identifying tube impacting and in the recognition of impacting in signal time histories, and to provide guidance on the identification of threshold levels for large amplitude vibrations due to fluidelastic excitation. There are numerous methods available for detecting tube impacting and for defining the threshold flow rate for instability from tests and associated test data. These are reviewed below together with sample data plots.

E-2 AURAL OBSERVATIONS

In general, tube vibration amplitudes increase dramatically when the critical flow rate is reached, often causing the tubes to impact with one another or with the tube support plates. Typically, a distinctive, loud noise associated with the metal-to-metal impacting is readily audible. The method is applied by increasing the flow in steps, or continuously at a slow rate, and listening for an abrupt increase in sound level. When the tubes are vibrating at sufficiently large amplitudes to cause audible impacting, it should be regarded as evidence that excessive tube vibration is highly probable.

One disadvantage of this method is that it is somewhat subjective and requires some engineering judgment and experience. A second disadvantage is that the results may not be conservative, considering that the tubes may have gone unstable at moderate amplitudes without impacting, at a somewhat lower flow than that identified by listening. An obvious advantage is that the method is fast, easy to apply, and allows for surveillance of the entire bundle at one time.

E-3 ACCELEROMETER SIGNAL CHARACTERISTICS DURING METAL-TO-METAL IMPACTING

The use of shell-mounted or in-tube accelerometers and microphones mounted in tube ends to detect metal-to-metal impact is reported in the references in paras. E-6(a) and (b). The appearance of an accelerometer signal time history with tube impacting is shown in Fig. E-1. In some cases, impacting is buried in the wide-band signal and may not be detectable without filtering [see para. E-6(k)]. In such cases, high-pass filtering improves the detection of impacting (see Fig. E-1). Further characterization of the impacting is possible with the use of an envelope detector [see para. E-6(b)]. Figure E-2 presents a comparison of concurrent time histories of an in-tube accelerometer and a tube-end microphone mounted in the same tube, demonstrating the one-to-one correspondence of events.

Impacting is also reflected in the acceleration signal frequency spectrum as a high frequency narrow-band peak (see Fig. E-2).

E-4 DETECTION OF VIBRATION CAUSED BY FLUIDELASTIC EXCITATION WITH TUBE-MOUNTED SENSORS

The methods described below each require instrumenting selected tubes with accelerometers or other motion-sensing devices. Again, the flow is increased in steps or swept at a slow rate starting from a low value. Typically, the response time histories are recorded on magnetic tape for subsequent data processing. With tube-mounted vibration sensors, indications of the possible onset of fluidelastic vibration are as follows:

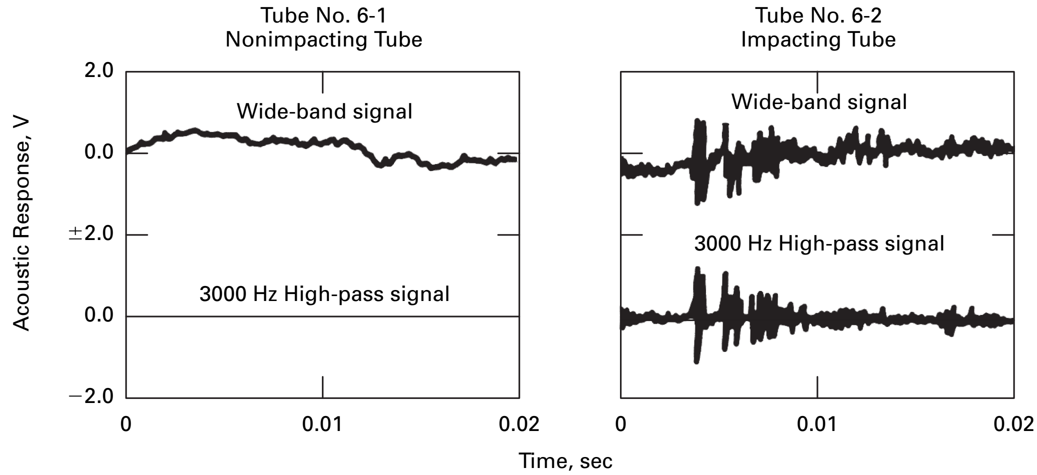
(a) high rate of increase in the tube vibration response versus increase in flow rate

(b) change in frequency response from multiple, closely spaced frequencies to a single, well-defined frequency

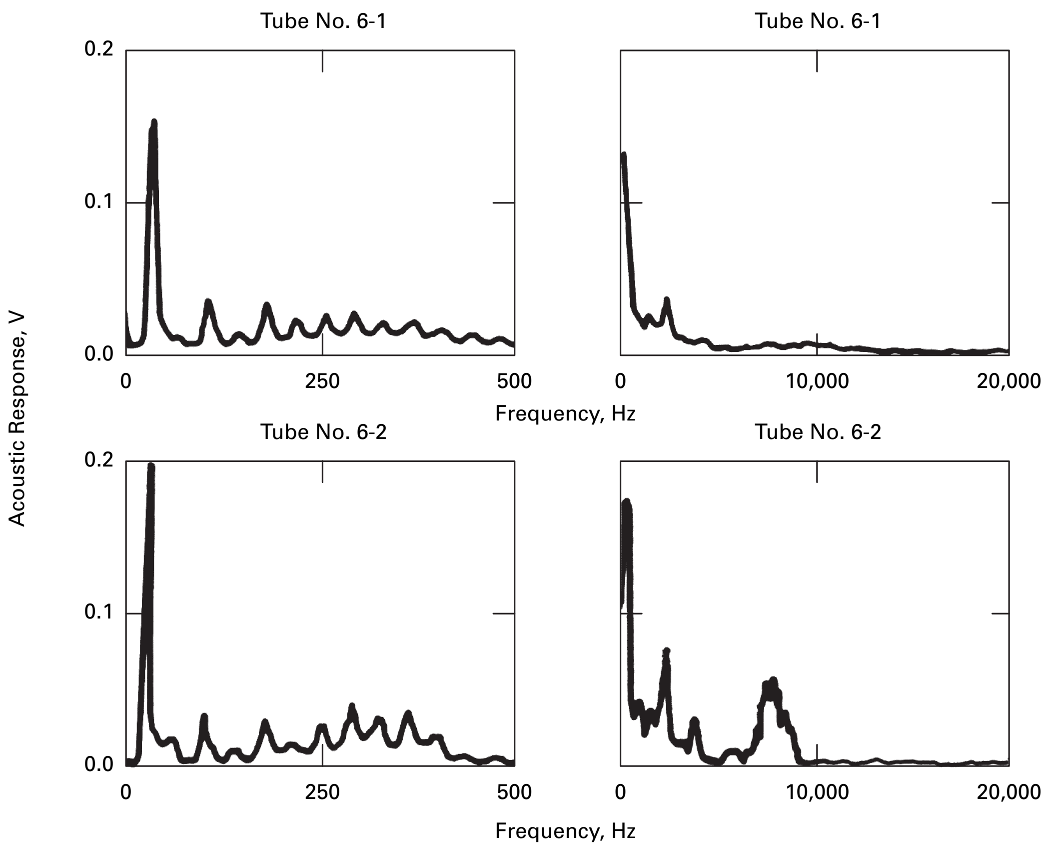
(c) change from a random to a well-defined tube trajectory

Several examples of heat exchanger tube amplitude plots and frequency spectra are presented as further background on the detection of vibration caused by fluidelastic excitation described in Nonmandatory Appendix A. These examples have been chosen to show the

Fig. E-1 Acoustic rms Spectrum for Nonimpacting Tube (No. 6-1) and Impacting Tube (No. 6-2)

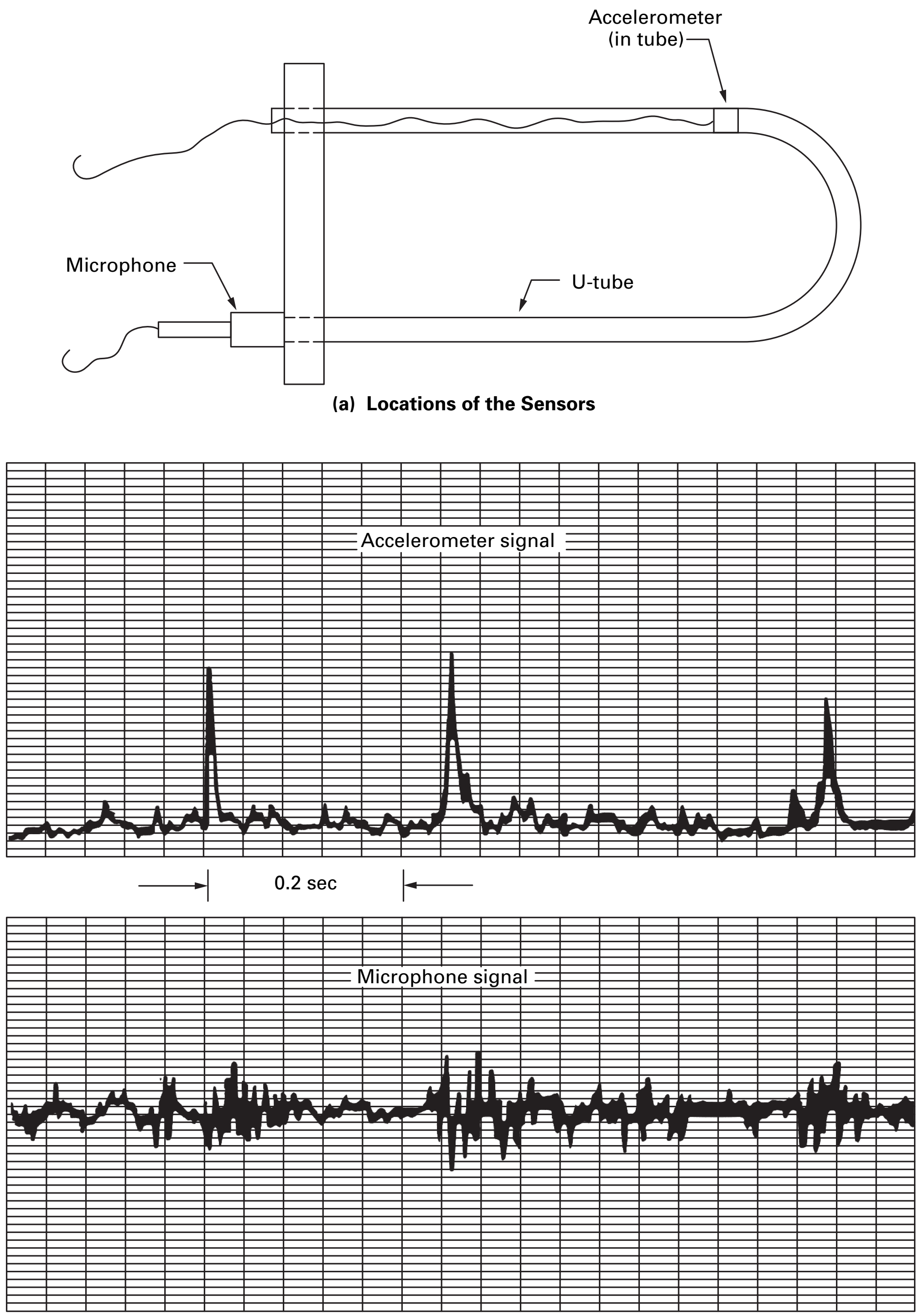


(a) Time History Plots for Impacting and Nonimpacting Tubes



(b) Acoustic rms Spectrum for Nonimpacting Tube (No. 6-1) and Impacting Tube (No. 6-2)

Fig. E-2 Correlation of Signals From Microphone and In-Tube Accelerometer



(b) One-to-One Correspondence of Events

detection methods and to point out difficulties inherent in interpretation of the data.

E-4.1 Vibration Amplitude Versus Flow Response Rate

The tube vibration response time histories are processed to obtain rms values of acceleration or displacement. The rms response is plotted as a function of flow velocity or flow rate. Illustrations of the types of curves that can be obtained are shown in Fig. E-3. The flow velocity at which the tube experiences a rapid increase in response is defined as the critical flow velocity. The reference in para. E-6(c) defines the critical flow velocity as the intersection of the velocity axis and the tangent to that portion of the curve that is rapidly rising [see Fig. E-3, sketch (a)].

Figure E-3, sketch (a) is the ideal and there is no problem in defining the critical flow rate with this method. However, typically (with water on the shell side) the response versus flow curve may peak, drop off, and then show a rapid rise. See, for example, Fig. E-3, sketch (b). There is uncertainty in such cases as to whether or not the first peak indicates instability. Problems in definition also arise in cases in which the rms response exhibits a gradual increase to a high level, as in Fig. E-3, sketch (c), rather than an abrupt increase, as in Fig. E-3, sketch (a). This gradual trend has been observed to occur with two phase flow on the shell side of the heat exchanger.

Typical response versus flow curves are given in Figs. E-4 and E-5. The data given in Fig. E-4, sketch (a) are from laboratory tests of a 5 × 5 tube array exposed to cross-flow; the curves correspond to various tubes within the array [see para. E-6(a)]. Figure E-4, sketch (a) represents an example of a well-defined instability similar to that illustrated in Fig. E-3, sketch (a); the critical flow velocity can be readily established. The curves of Fig. E-4, sketch (b), on the other hand, are of the type illustrated in Fig. E-3, sketch (b) and are more difficult to interpret. It has been suggested that the peak in the response curve may be associated with response due to vortex shedding. Experience has shown that the instability is better defined for cases involving high damping.

The data given in Fig. E-5 are from four different tubes in a vibration test of an industrial size, segmentally baffled, shell-and-tube heat exchanger with water as the shell-side fluid; data were obtained both sweeping up and sweeping down in flow [see para. E-6(e)]. Examination of the curves of Fig. E-5 leads to the following observations, which serve to demonstrate the types of response one can expect from a vibration test:

(a) All four tubes exhibit a peak in the response curve with increasing flow rate; the peak is nonexistent for decreasing flow.

(b) Hysteresis is present for two cases [see Fig. E-5, sketches (b) and (c)]; the flow rate at which the instability

Fig. E-3 Rms Tube Response Versus Flow Velocity

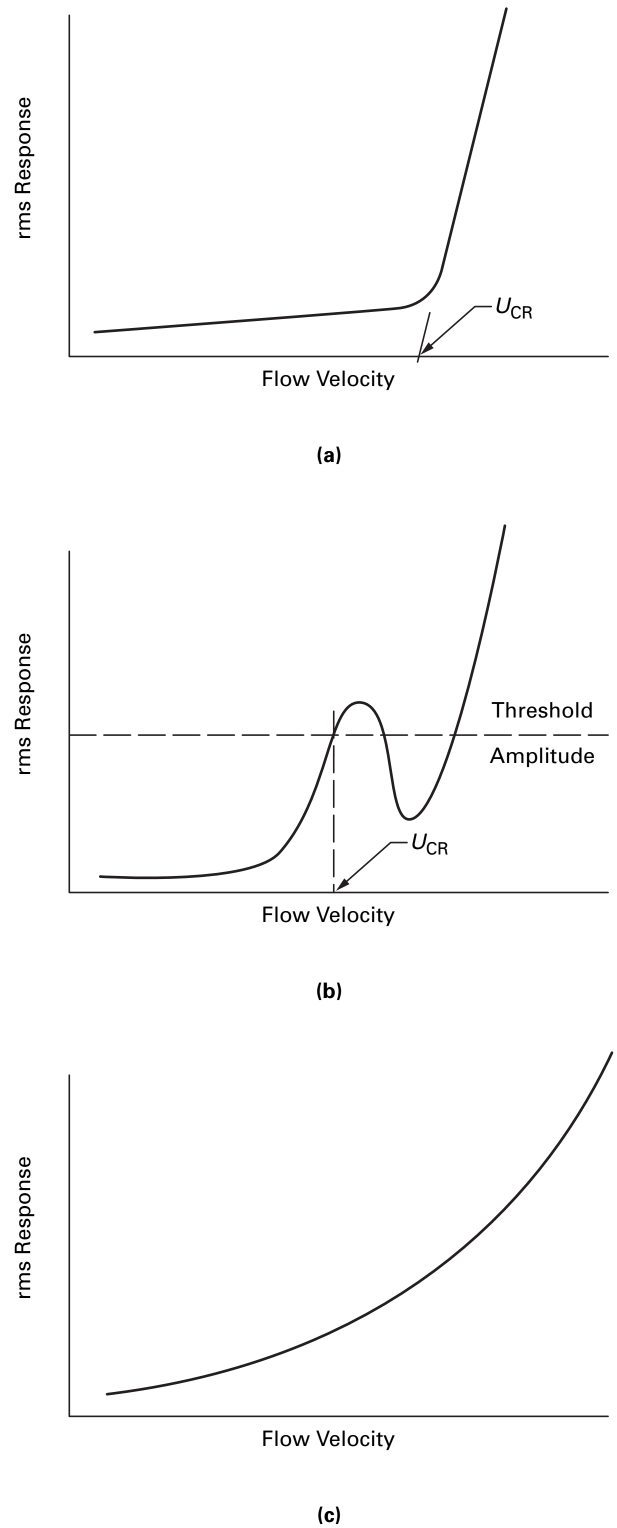
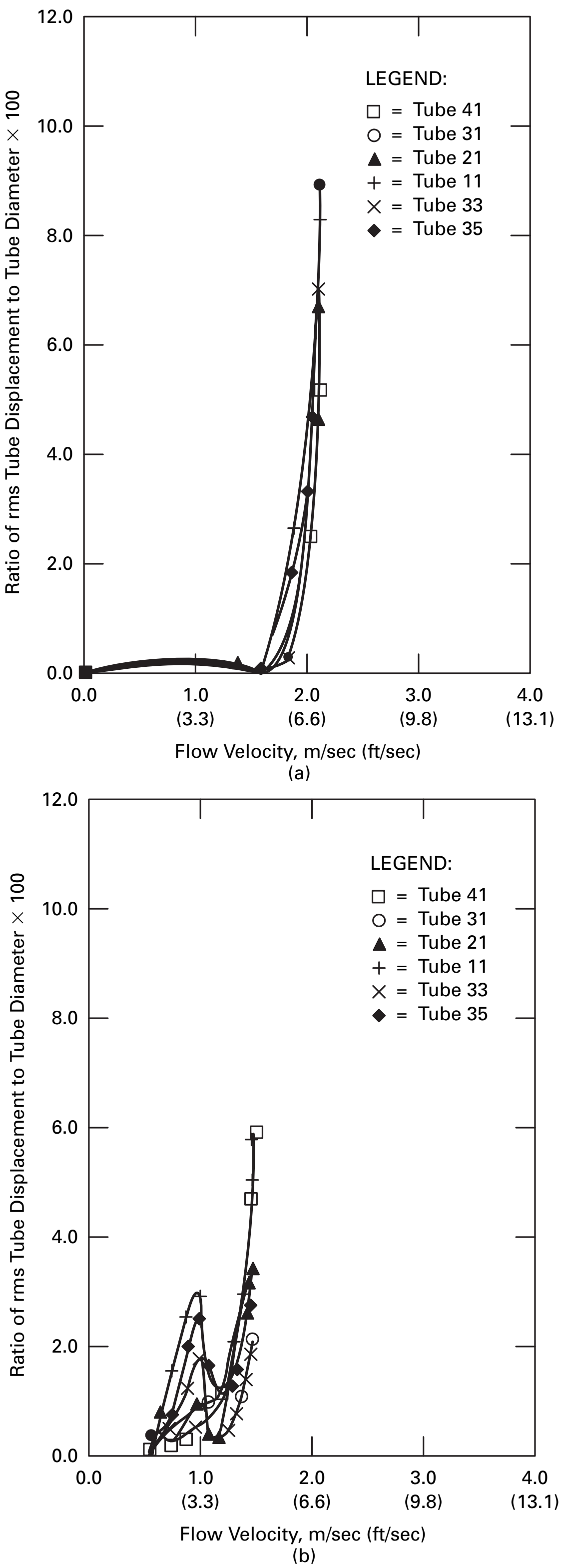


Fig. E-4 Response Versus Flow Velocity (Laboratory Test of 5 × 5 Tube Array)



drops out is less than the threshold for the onset of instability.

(c) The instability flow rate is well defined in Fig. E-5, sketches (b) and (c); the increase in response is very abrupt.

(d) It is more difficult to define a critical flow rate in Fig. E-5, sketch (a); the rate of increase of response with flow rate is relatively gradual.

E-4.2 Vibration Amplitude Versus Flow Amplitude Threshold

To overcome the ambiguity in establishing the critical flow velocity for cases in which the rms response versus flow curves exhibit "undulations," a gradual rise, or both, several investigators have established a "threshold displacement amplitude." The critical flow velocity is defined as the velocity at which the threshold displacement is first exceeded.

Once a threshold amplitude is established, the method is straightforward in application [see Fig. E-3, sketch (b)]. However, again, engineering judgment is required in the selection and application of the criterion. See, for example, para. E-6(f).

E-4.3 Time History

A slow sweep up in flow is performed while tube acceleration time histories are recorded on magnetic tape. A careful examination of the time histories is carried out to determine the time (corresponding to a particular flow) at which large amplitudes suddenly occur. Peak amplitudes can be compared with the available clearance to determine if impacting between tubes can be expected to be occurring (with measurements from adjacent tubes or on the assumption of similar amplitudes of adjacent tubes).

In application of this method, the relationship of the vibration mode relative to the axial location of the accelerometer in the tube must be considered. Depending on the mode shape, the peak response in one span can be significantly greater than that in an adjacent span. Therefore, if the accelerometer is located in a span with a smaller relative motion, analysis of the response peaks may indicate that impacting is not occurring whereas it may, in fact, be occurring in an adjacent span. This method can be rather tedious and time-consuming to apply. It, too, requires engineering judgment.

Sample time histories from a heat exchanger tube vibration test are shown in Figs. E-6 and E-7 [see para. 6(g)]. The flow rate is being slowly increased with time. The rather abrupt buildup of large-amplitude motion is the result of a fluidelastic instability. The time of occurrence can be correlated with a flow rate versus time history to determine the critical flow rate. Displacement time histories are also useful in assessing possible tube-to-tube impacting; peak amplitudes can be compared with tube spacings and available clearance. In addition,

Fig. E-5 Response Versus Flow Rate for Four Tubes in Industrial Size Shell-and-Tube Heat Exchanger (Open Symbol: Increasing Flow; Solid Symbol: Decreasing Flow)

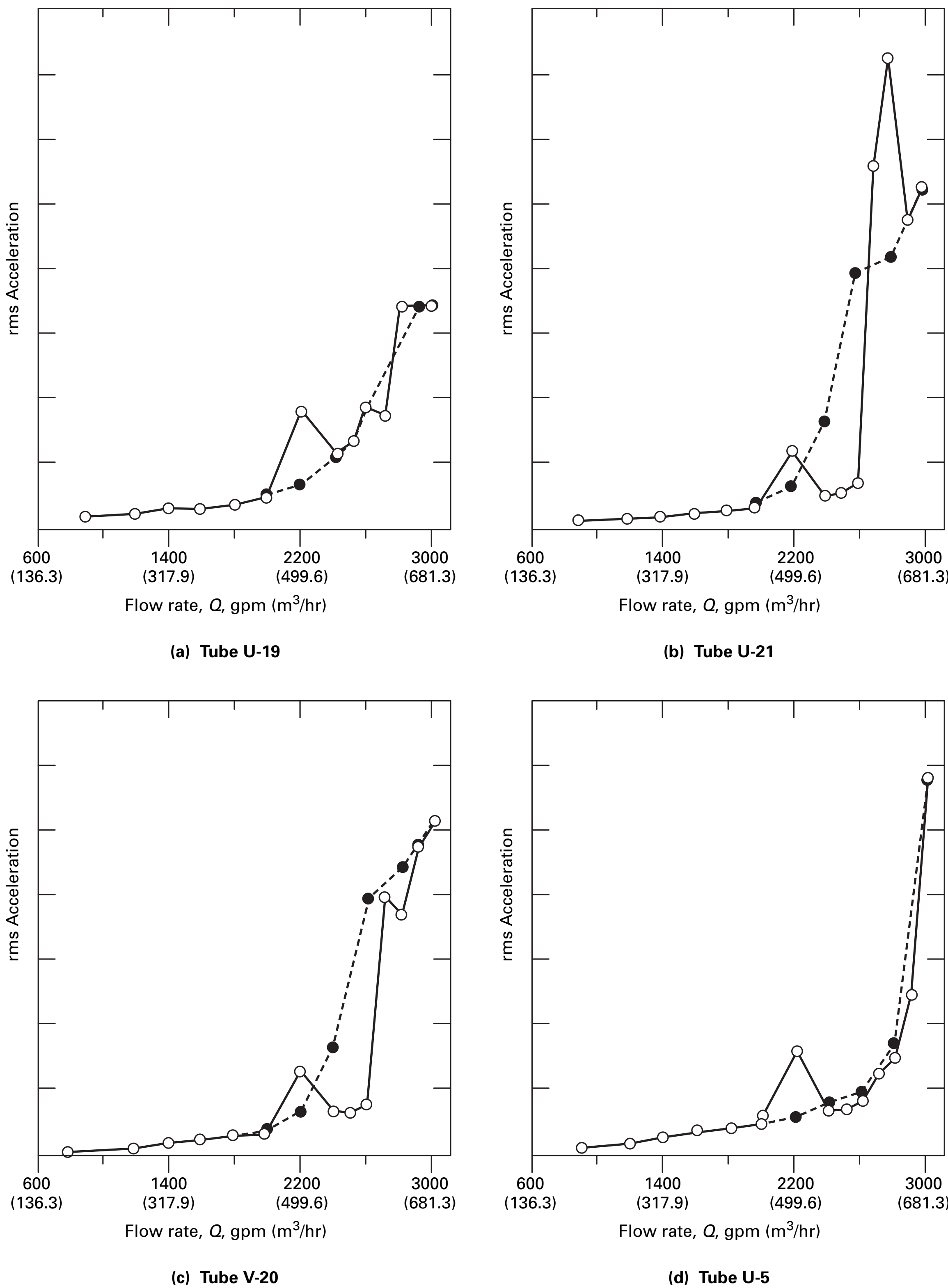


Fig. E-6 Displacement Time Histories From Accelerometer Pair in Heat Exchanger Tube Vibration Test

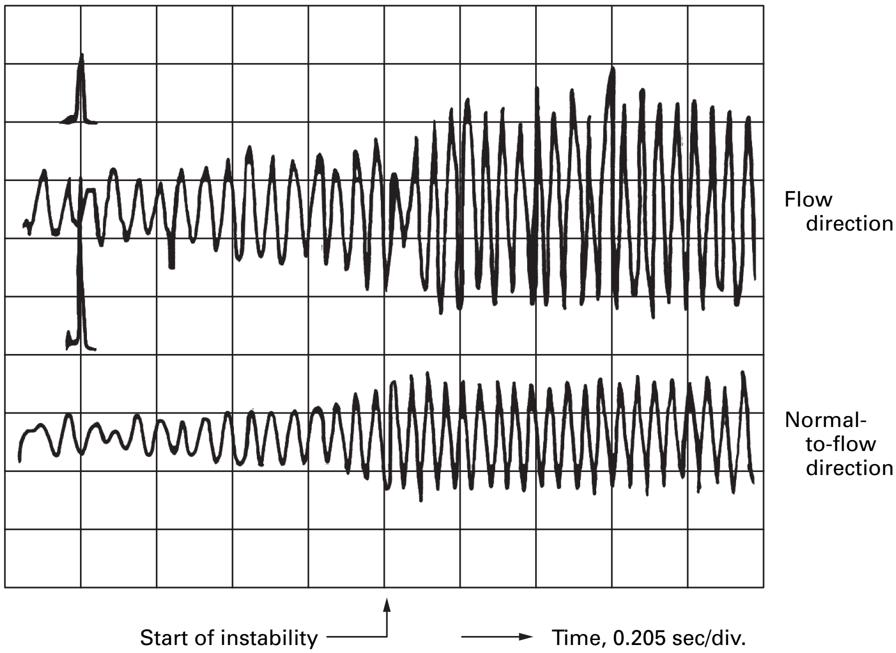
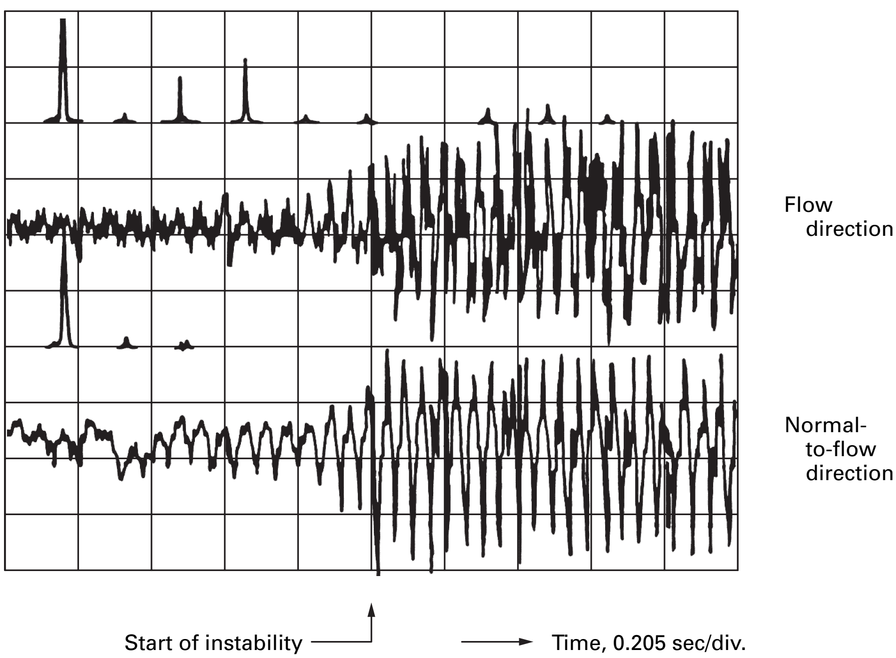


Fig. E-7 Acceleration Time Histories From Accelerometer Pair in Heat Exchanger Tube Vibration Test

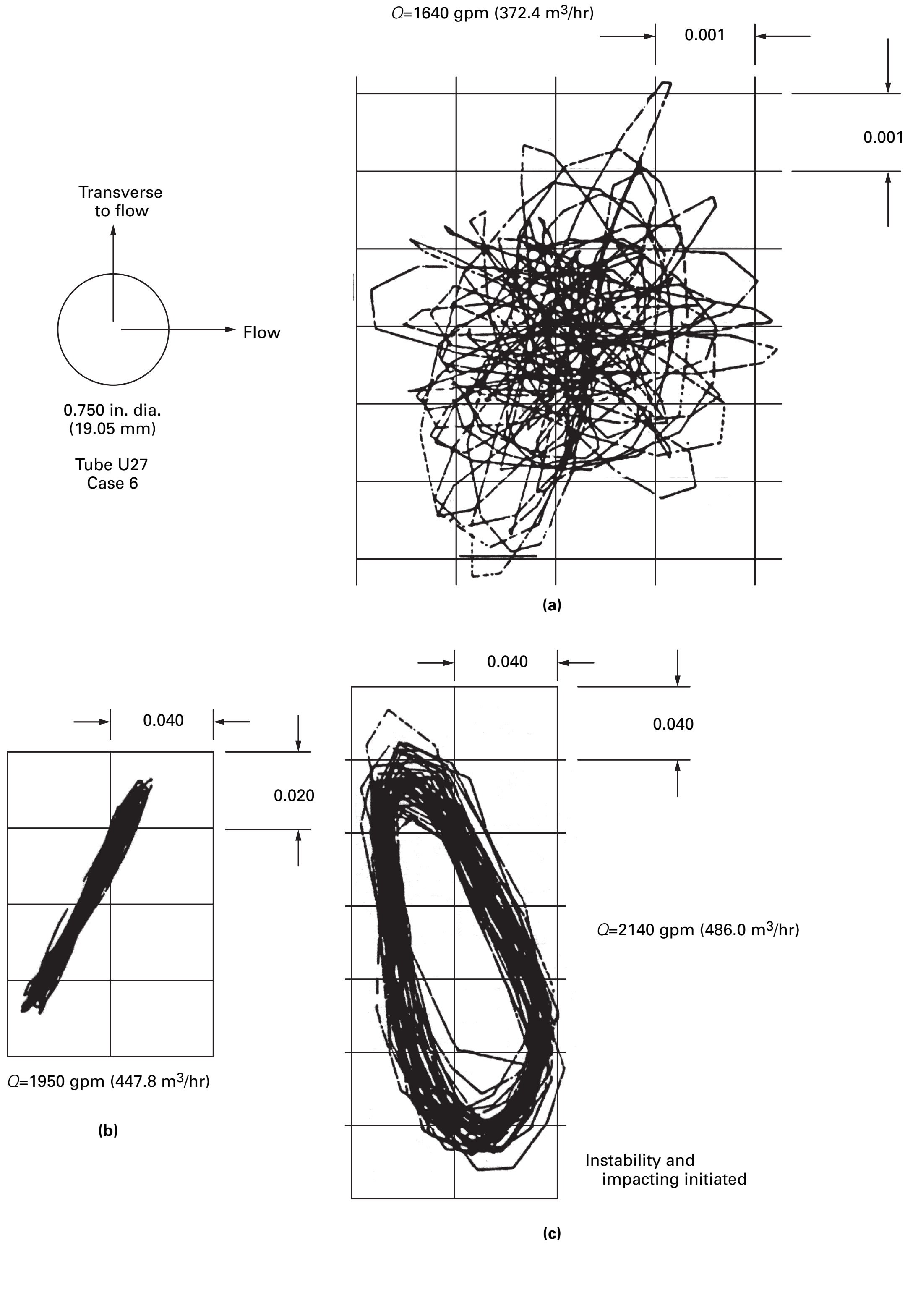


acceleration time histories should be reviewed for indications of impacting as discussed in para. E-3.

E-4.4 Tube Trajectory

In situations in which an accelerometer pair, with axes in an orthogonal orientation, is employed, patterns of the spatial trajectories (x-y motion) of a tube, obtained from time histories, can be useful in interpreting the dynamic response and onset of instability. A typical example is given in Fig. E-8 [see para. E-6(e)]; the trajectories are from an accelerometer pair located in a tube of an industrial-size, shell-and-tube heat exchanger. At a flow rate of 1,640 gpm (372.4 m^3/hr), the pattern of tube motion is random and the amplitude of response

Fig. E-8 Tube Vibration Patterns From X-Y Probe and Test of Industrial Size Shell-and-Tube Heat Exchanger



is low [peak-to-peak amplitude of 6 mils (0.15 mm)]. At approximately the instability flow rate [1,950 gpm (442.8 m^3/hr)], the motion becomes organized into a nearly straight-line pattern primarily in the transverse-to-flow direction; the peak-to-peak amplitude has increased to approximately 60 mils (1.5 mm), ten times that of the lower flow rate. As the flow rate is increased further, to 2,140 gpm (486.0 m^3/hr), the tube begins to whirl and to impact adjacent tubes; the peak-to-peak amplitude is now greater than 240 mils (6.1 mm) with the motion limited by impacting.

E-4.5 Frequency Response Data

The critical flow velocity can be thought of as the flow velocity defining the transition from turbulent buffeting to fluidelastic instability. When a tube bundle is immersed in a dense fluid such as water, fluid structure coupling occurs, which gives rise to a broad band of closely spaced frequencies, centered about what would be the natural frequency of an isolated tube in the fluid. At flow velocities below the critical value, turbulent buffeting is the dominant excitation mechanism. It excites this broad range of coupled frequencies, as evidenced from the response power spectral density curves. On the other hand, the vibration at instability will typically be at a well-defined, single frequency (corresponding to the instability mode).

In application of this method, the vibration response time histories are processed on a Fast Fourier Transform Analyzer to obtain power spectral density (PSD) representations of the data. The flow velocity (or flow rate) at which the response PSD changes from a relatively broad-band spectrum to a narrow-band (single-frequency) spectrum is defined as the critical flow velocity (see, for example, Nonmandatory Appendix A, Fig. A2).

Figure E-9 is from a vibration test in which the flow was both increased and decreased in incremental steps [see para. E-6(e)]. Response spectra for flow rates from 900 gpm to 2,600 gpm (204.4 m^3/hr to 590.5 m^3/hr) are representative of turbulent buffeting excitation. The sharp, single-frequency response at 2,700 gpm (613.2 m^3/hr) is interpreted to indicate that the transition from turbulent buffeting to fluidelastic instability took place in the range 2,600 gpm to 2,700 gpm (590.5 m^3/hr to 613.2 m^3/hr). The multiple-frequency response at flow rates from 2,800 gpm to 3,000 gpm (635.9 m^3/hr to 681.3 m^3/hr) is expected to be the result of impacting with adjacent tubes and/or rattling in the baffles. As the flow rate is decreased from 3,000 gpm (681.3 m^3/hr), it is interesting to observe that a well-defined, single-frequency instability mode frequency appears once again. The dropout of instability or transition from instability to a dominant turbulence response occurs between 2,200 gpm and 2,000 gpm (499.6 m^3/hr to 454.2 m^3/hr), as indicated by the change in character of the response spectra. These results are in good agreement with the results from sensory observations.

In general, this method is felt to be reasonably reliable for heat exchangers with dense shell-side fluids. However, engineering judgment is still required in situations in which the broad-band spectra associated with turbulent buffeting "narrow" significantly before becoming extremely sharp or when the amplitude and/or frequency change abruptly due to a change in the tube support configuration. Also, in cases in which the instability is very abrupt, the large amplitudes might initiate impacting that, in turn, will be represented as a broad frequency range on the PSD. In this case, the single-frequency spike representative of instability might not be detected.

Each of the above methods are somewhat subjective and dependent on engineering judgment. In determining the critical flow rate for a heat exchanger bundle, it is advisable to employ all the available methods and to compare the results from one against those from another. In particular, since it is practically possible to instrument only a small percentage of the large number of tubes in the bundle, it is necessary to scan the tube ends to identify those tubes and groups of tubes that first experience large-amplitude motion. Selected tubes, from those so identified, can then be instrumented, and one or more of the other methods, which are dependent on response data, can be applied to determine more accurately the onset and dropout (with decreasing flow) of instability.

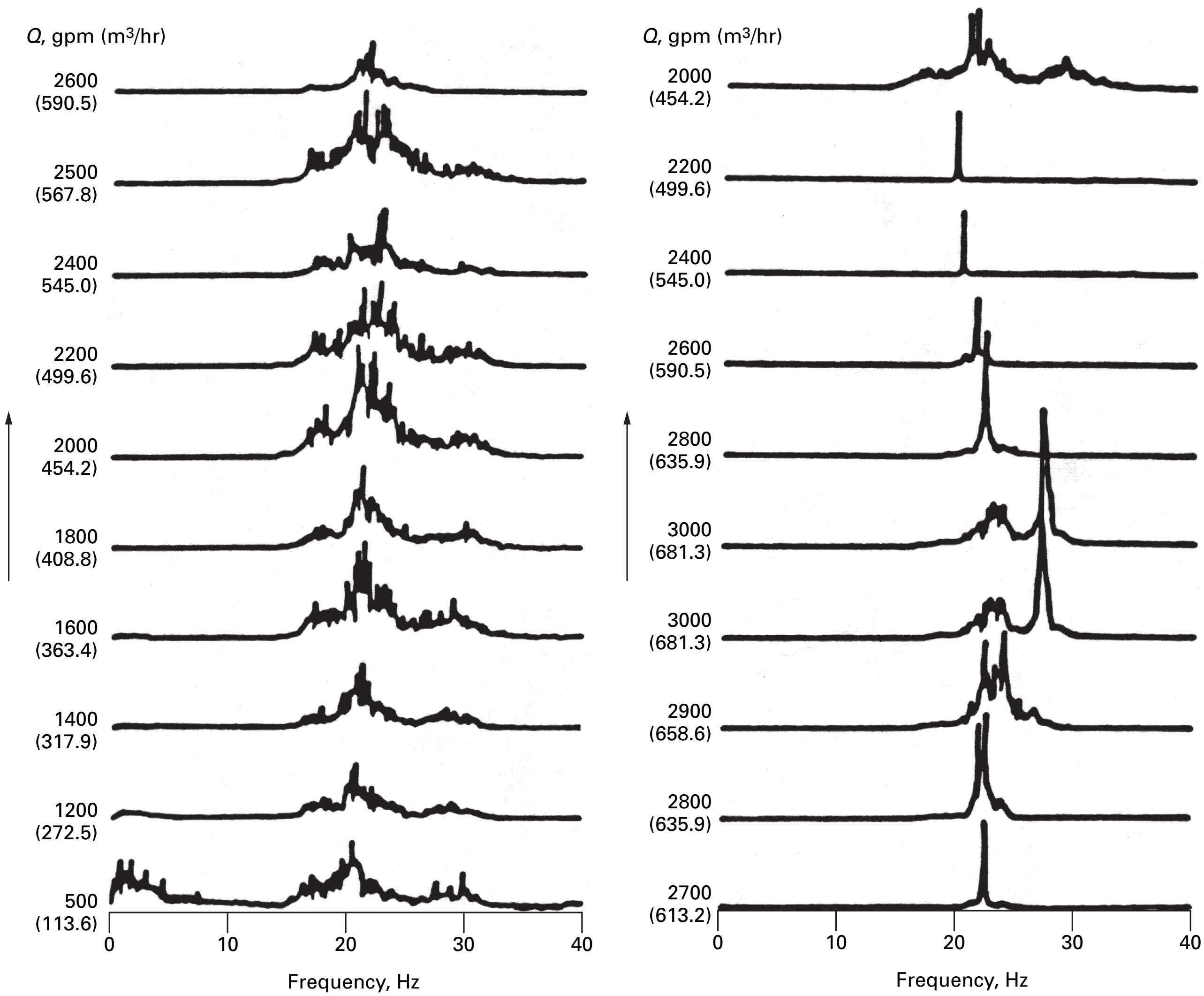
E-5 TUBE SUPPORT PLATE INTERACTION

Clearances between tubes and tube support plate holes are inherent in the design of heat exchangers; it is common for the tube holes to be drilled 0.4 mm to 0.8 mm over the outside diameter of the tubes. Depending on initial tube straightness, mechanical fit-up, and operating conditions, it is possible for a tube to be effectively centered within the tube support plate hole. In such cases the tube support plate does not provide effective support and the tube may vibrate due to turbulence excitation or experience instability in a so-called tube support plate inactive mode. Steady drag is an important consideration. The potential for occurrence of this phenomenon is increased for heat exchangers with relatively large tube to support plate hole clearances and short (stiff) spans (tubes with long, inherently flexible spans will respond to the steady drag exerted by the shell-side flow and will typically be forced against the support plate).

This vibration of a tube in a tube support plate inactive mode has been observed in the field and in laboratory tests. Discussions of effects of tube and support interaction due to turbulence excitation are included in the references in paras. E-6(h) through (m). Laboratory results obtained regarding the effects of clearances on fluidelastic response of tubes are discussed below.

The laboratory setup and typical results are given in Figs. E-10 through E-13 [see para. 6(n)]. Again, initial

Fig. E-9 Frequency Response Curves for Tubes in Industrial Size Shell-and-Tube Heat Exchanger



clearance, initial preload for the case of initial clearance equal to zero, and steady drag are all important, contributing factors. Figure E-11 is a plot of tube response as a function of flow velocity for two measurement locations as indicated in Figs. E-10 and E-11. It clearly shows the existence of the two instability types. Figure E-12 gives representative frequency response spectra as a function of flow velocity. Sample time histories corresponding to selected flow rates are given in Fig. E-13. The data are presented as a further aid to the user in interpretation of data obtained from vibration tests.

E-6 REFERENCES

The following is a list of publications referenced in this Appendix.

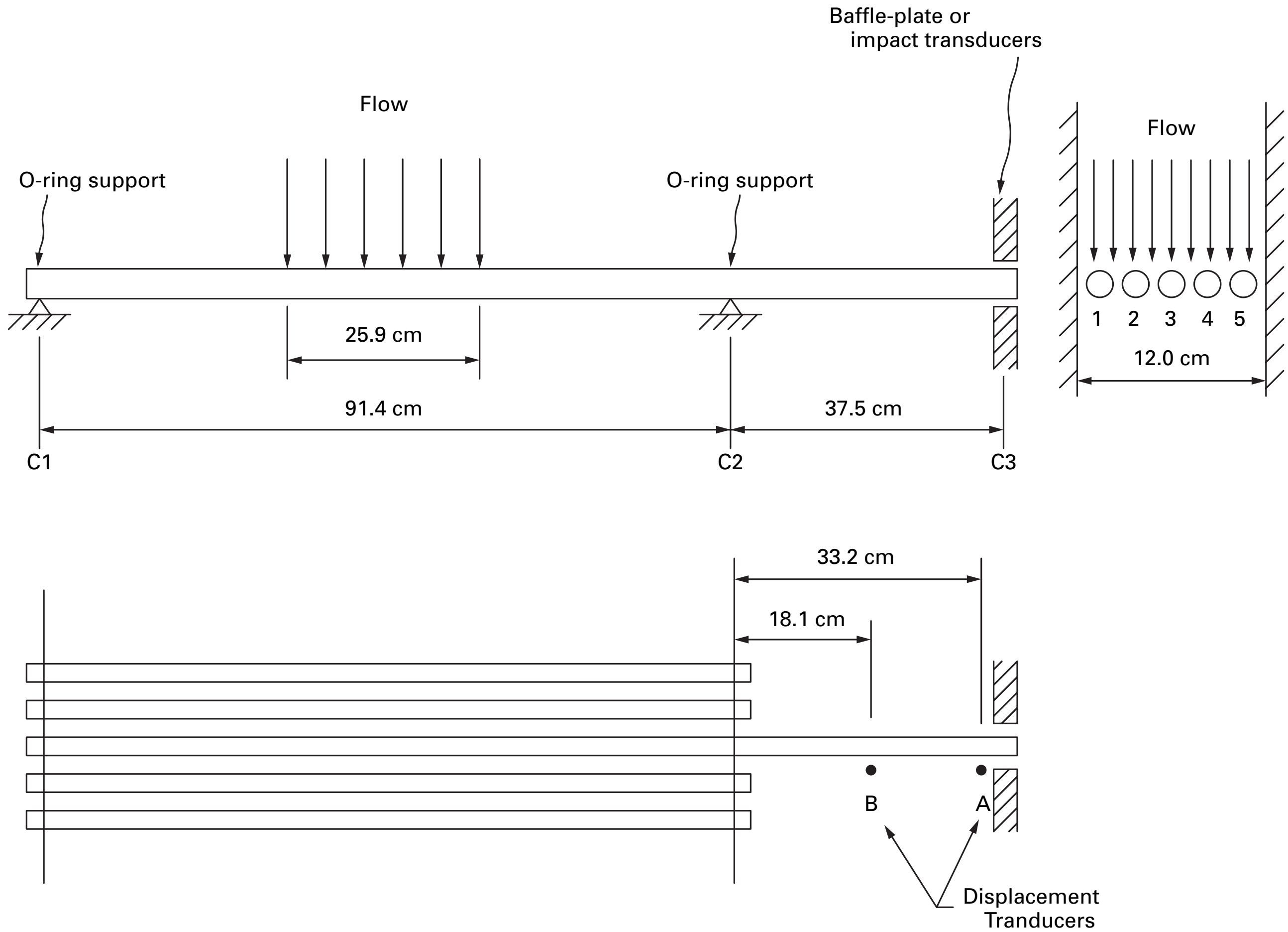
R. T. Hartlen and W. Jaster, "Flow-Induced Vibration of Tubes in Operational Heat Exchangers: Some Experiences in Detection and Diagnosis by Vibroacoustics Measurements," ASME HTD-Vol. 9, Flow-Induced Heat Exchanger Tube Vibration (1980)

R. B. Wilson and J. E. Gillett, "Vibroacoustic Method to Detect Heat Exchanger Tube Vibrational Impacting," ASME 84-NE-1 (1984)

B. M. H. Soper; J. M. Chenoweth and J. R. Stenner, eds.; "The Effect of Tube Layout on the Fluidelastic Instability of Tube Bundles in Cross Flow," Flow-Induced Heat Exchanger Tube Vibration, ASME HTD-Vol. 9 (1980): 1–9

J. A. Jendrzejczyk, personal communication with (Argonne National Laboratories, 1984)

Fig. E-10 Schematic of Test Setup



H. Halle and M. W. Wambsganss, "Tube Vibration in Industrial Size Test Heat Exchanger (90 Deg. Square Layout)," ANL Report ANL-83-10 (February 1983)

H. C. Yeung and D. S. Weaver, "The Effect of Approach Flow Direction on the Flow-Induced Vibrations of a Triangular Tube Array," ASME Journal of Vibration, Acoustics, Stress, and Reliability, Vol. 105 (1981): 76–82

H. Halle, personal communication with (Argonne National Laboratory, 1984)

R. Bouecke and G. Schuctanz, "Experience With KWU Steam Generators," Part 2, KWU Steam Generator Concept with Economizer, NEA/CSNI-UN-IPEDE Specialist Meeting on Steam Generators (Stockholm, Sweden; October 1–5, 1984): Section 6.3

T. M. Frick, T. E. Sobek, and J. R. Reavis, "Overview on the Development and Implementation of Methodologies to Compute Vibration and Wear of Steam Generator Tubes," Flow-Induced Vibration in Heat Exchangers, Symposium on Flow-Induced Vibration, ASME Winter Annual Meeting (New Orleans, LA; Dec. 9–13, 1984)

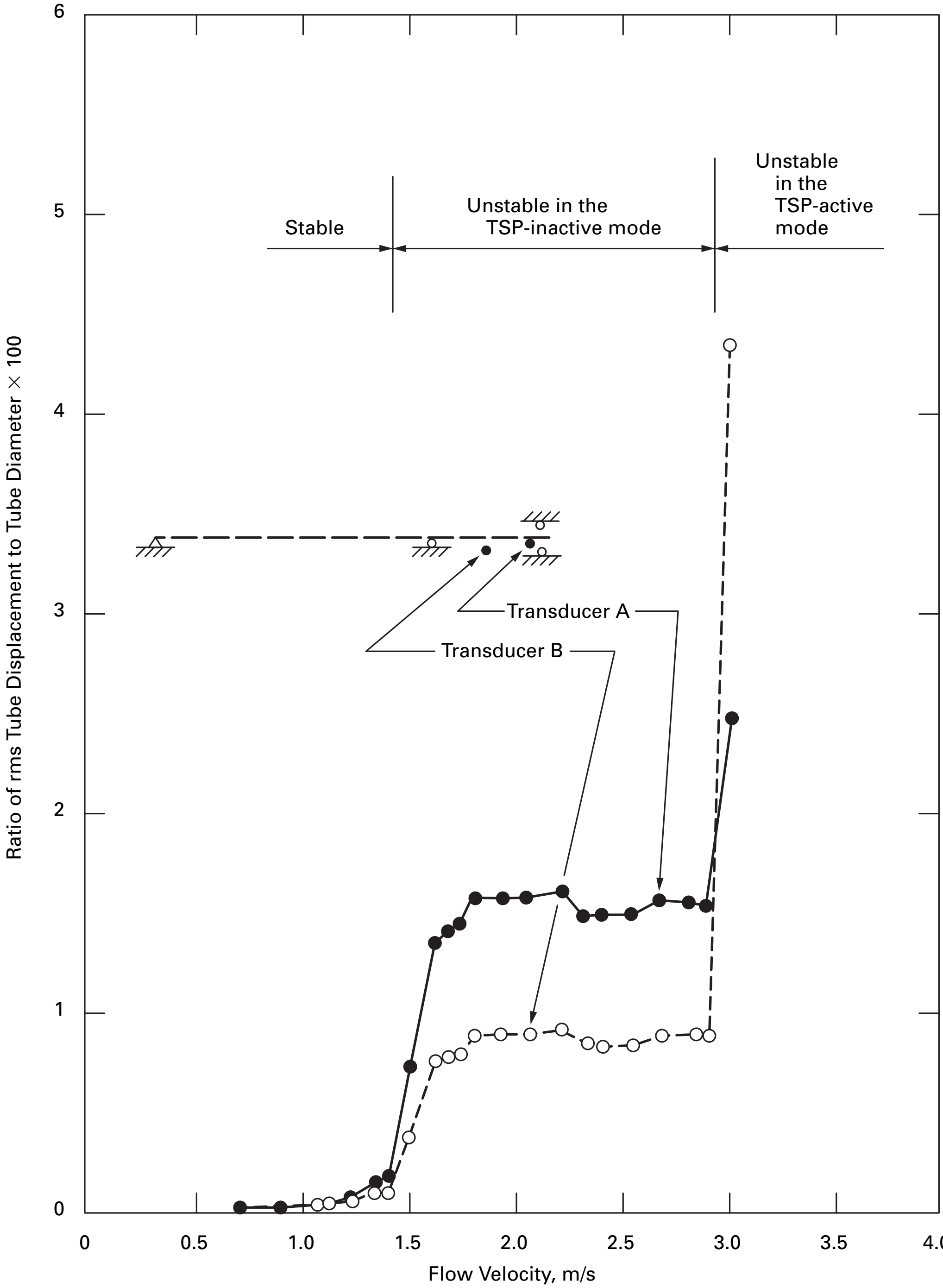
K. H. Haslinger and D. A. Steininger, "Steam Generator Tube/Tube Support Plate Interaction Characteristics," Symposium on Flow-Induced Vibration, ASME Winter Annual Meeting (New Orleans, LA; December 9–14, 1984): Vol. 3

P. J. Hofmann, T. Schettler, and D. A. Steininger, "Pressurized Water Reactor Steam Generator Tube Fretting and Fatigue Wear Characteristics," ASME PVP-2, ASME PVP Conference (Chicago, July 21–24, 1986)

M. J. Pettigrew and P. L. Ko, "A Comprehensive Approach to Avoid Vibration and Fretting in Shell-and-Tube Heat Exchangers," Flow-Induced Vibration of Power Plant Components, ASME PVP-41 (August 1980)

N. R. Singleton, "Design Resolution of Westinghouse Reheat Steam Generator Flow-Induced Vibration Concerns," NEA/CSNI-UNIPEDE Specialist Meeting on Steam Generators (Stockholm, Sweden; October 1–5, 1984): Section 1.6

Fig. E-11 Rms Tube Displacements As Function of Flow Velocity (Diametral Gap of 1.02 mm)



S. S. Chen, J. A. Jendrzejczyk, and M. W. Wambsganss, "Dynamics of Tubes in Fluid With Tube-Baffle Interaction," ASME Pressure Vessel Technology, Vol. 107 (1985): 7–17

Fig. E-12 Frequency Spectra of Tube Displacement at Location "A" (Diametral Gap of 1.27 mm)

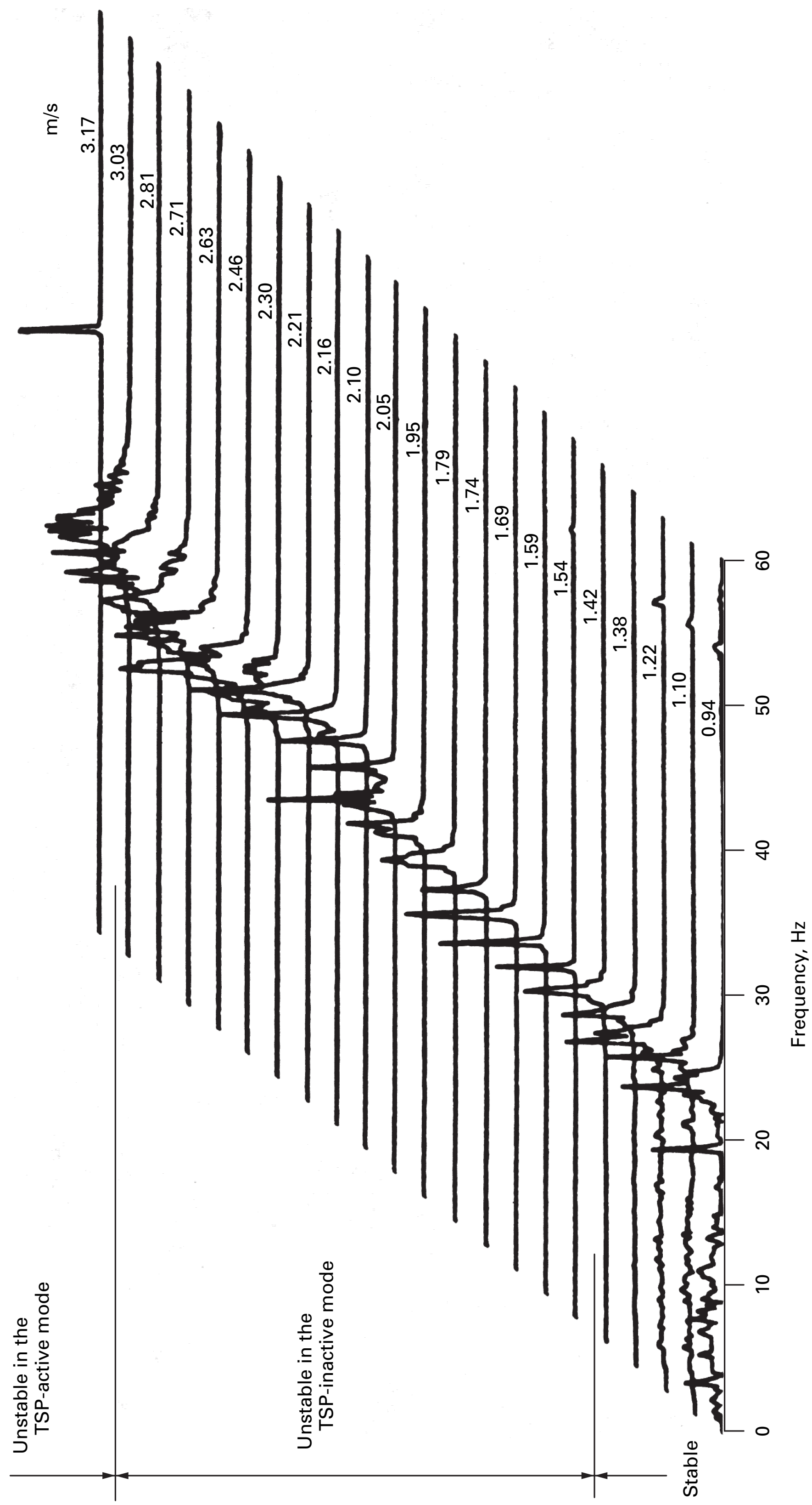
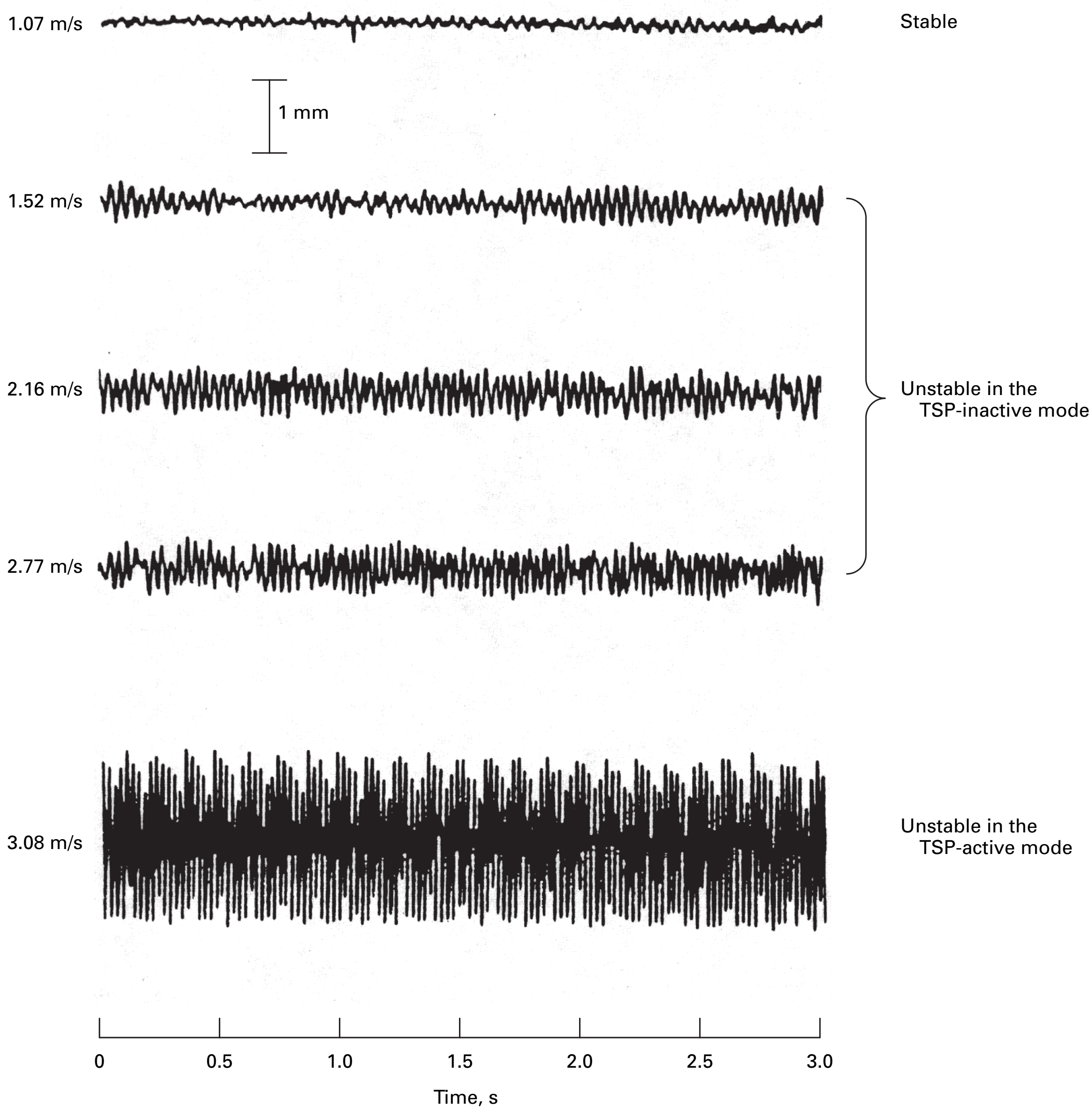


Fig. E-13 Tube Displacement Time Histories at Location "A" (Diametral Gap of 0.51 mm)



PART 11
NONMANDATORY APPENDIX F
Vibration Acceptance Guidelines

F-1 INTRODUCTION

For some heat exchangers, a review of the data that reveals no indications of strong vibration may be an adequate basis for acceptance. In some cases, periodic inspection for wear, by eddy current testing, for example, may be appropriate [see para. F-6(a)].

Guidelines for an initial assessment are provided in para. F-2. Possible follow-up actions are listed in para. F-3. If a more complete assessment is justified by the importance of the heat exchanger, previous experience, or unacceptable results from the initial evaluation, a more detailed program may be required. Information in the literature that may support a detailed assessment of the wear rate implied by tube vibration measurements are summarized in para. F-4. Sources of background information relative to external surveys are provided in para. F-5.

F-2 GUIDELINES FOR INITIAL ASSESSMENT

Data evaluation results for which further action is recommended are described below.

(a) Excessive Fatigue Stresses. Review the data to determine tube displacement shapes and amplitudes. Calculate and evaluate fatigue stresses.

(b) Contact Between Adjacent Tubes. Determine maximum zero-to-peak tube vibration displacement amplitudes. Compare these amplitudes to tube-to-tube clearances to ensure that the likelihood of contact is adequately low.

(c) Frequent Impacting Between the Tube and Tube Support. Although tube vibration may be acceptable with some impacting, if continuous or intermittent impacting is present, further action (such as listed below) is recommended unless information is available that indicates this is not necessary. Sample time histories and techniques for the detection of impacting are provided in Nonmandatory Appendix E.

(d) Presence of Fluidelastic Vibration. Review the data for indications of vibration caused by fluidelastic excitation. Fluidelastic vibration is usually evidenced by an increase in the rate of change of vibration level as flow rate is increased (although this could also be a result of vibration in a different mode due to a change in the tube support pattern). Indications that the tube is undergoing circular motions or sharpening of the frequency spectrum also can indicate that the tube is vibrating due to fluidelastic excitation (see Nonmandatory Appendix E). Although the existence of fluidelastically excited tube vibration does not necessarily imply an unacceptable wear rate, this mechanism is frequently the cause of excessively high vibration levels.

F-3 FOLLOW-UP ACTIONS

One or more of the following can be implemented if vibration levels are not acceptable:

(a) Review existing design information and perform additional analysis as indicated to attempt to identify the cause and possible remedial actions.

(b) Limit the heat exchanger flow rate.

(c) Install modifications to reduce vibration levels and retest to verify adequacy.

(d) If it can be shown that an acceptably small number of tubes are considered to be potentially unacceptable, these tubes may be removed from service with consideration of the need for precautions against subsequent damage.

(e) Perform a detailed assessment.

F-4 METHODS FOR DETAILED WEAR ASSESSMENTS

Several approaches that may support detailed assessment of the wear implied by accelerometer data and support the development of more specific acceptance criteria are in the literature [see the references in paras. F-6(a) through (g)].

These references report the following:

(a) the use of laboratory flow model wear measurements to project the wear of a specific heat exchanger with subsequent field verification

(b) the use of nonlinear modal analysis and experimental fluctuating force data to predict flow-induced tube motion and wear rate

(c) work on the development of correlations between tube motion characteristics and wear rate

(d) the correlations of tube-tube support interaction forces with wear rate

(e) correlation of field wear data and field accelerometer vibration measurements for wear evaluation of similar units

Extensive information is needed for the use of these approaches. The suitability of these methods for a particular heat exchanger should be determined on a case-by-case basis.

F-5 GUIDELINES FOR THE EVALUATION OF EXTERNAL VIBRATION LEVELS

In the absence of specific criteria for the equipment being tested, references may provide guidance for the evaluation of external vibration levels.

(a) Hartlen, Elmaraghy, and Slingerland, "Vibration Velocity as a General Severity Criterion," Canadian Electric Association Spring Meeting (March 1982).

This paper presents the rationale for using vibration velocity as the most generally useful parameter, and for expecting acceptance criteria to be roughly independent of the particular system details.

(b) DIN 4150, the German code addressing vibration in structures. There are three parts: Part 1, principles, predetermination, and measurement of the amplitude of oscillations; Part 2, influence on persons in buildings; and Part 3, influence on construction (in German).

(c) Part 3 of this document, ASME OM-S/G-2003, Requirements for Preoperational and Initial Start-Up Vibration Testing of Nuclear Power Plant Piping Systems.

Several methods for evaluating the severity of piping system vibrations are provided in this Part.

F-6 REFERENCES

The following is a list of publications referenced in this Appendix.

"Evaluation of Eddy-Current Procedures for Measuring Wear Scars in Preheat Steam Generators," Electric Power Research Institute Final Report, NP-3928 (April 1985)

R. Bouecke and G. Schuctanz, "Experience With KWU Steam Generators," Part 2, KWU Steam Generator Concept With Economizer, NEA/CSNI-UNIPEDE Specialist Meeting on Steam Generators (Stockholm, Sweden; October 1–5, 1984): Section 6.3

T. M. Frick, T. E. Sobek, and J. R. Reavis, "Overview on the Development and Implementation of Methodologies to Compute Vibration and Wear of Steam Generator Tubes," Symposium on Flow-Induced Vibration in Heat Exchangers, ASME Winter Annual Meeting (New Orleans, LA; December 9–13, 1984)

K. H. Haslinger and D. A. Steininger, "Steam Generator Tube/Tube Support Plate Interaction Characteristics," Symposium on Flow-Induced Vibration in Heat Exchangers, ASME Winter Annual Meeting (New Orleans, LA; December 9–14, 1984): Vol. 3

P. J. Hofmann, T. Schettler, and D. A. Steininger, "Pressurized Water Reactor Steam Generator Tube Fretting and Fatigue Wear Characteristics," ASME PVP-2, ASME PVP Conference (Chicago, IL; July 21–24, 1986)

M. J. Pettigrew and P. L. Ko, "A Comprehensive Approach to Avoid Vibration and Fretting in Shell-and-Tube Heat Exchangers," Flow-Induced Vibration of Power Plant Components, ASME PVP-41 (August 1980)

N. R. Singleton, "Design Resolution of Westinghouse Reheat Steam Generator Flow-Induced Vibration Concerns," NEA/CSNI-UNIPEDE Specialist Meeting on Steam Generators (Stockholm, Sweden; October 1–5, 1984): Section 1.6

PART 11
NONMANDATORY APPENDIX G
Installation of Strain Gages

Significant operations are required to install strain gages on the inner surface of tubes. Prior to installing the gages, the lead wires are attached to each gage to accommodate a three-wire bridge; two wires are attached to one strain gage terminal and one wire to the other terminal. The inside surface of the tube is cleaned using an expandable brake cylinder hone. During this operation, care must be taken to ensure that the interior surface of the tube is not damaged.

After honing, the surface should be inspected with a borescope. The surface is then cleaned using gauze swabs saturated with an appropriate cleaner. After the tubes are thoroughly cleaned the interior surface of the tube is heated. Heating the tube surface ensures that it is moisture-free and accelerates the curing of the strain gage adhesive. The strain gage is fixed to the surface of a length of surgical tubing. One end of the tube is plugged and the other end attached to a regulated air supply. The strain gage is coated with a few drops of glue. The rubber tube is inserted into the tube.

Once the strain gage is positioned, the rubber tube is inflated. After the glue cures, the rubber insertion tool is deflated and removed. The resistance of the gage must be checked and the gage installation examined using a borescope. If the installation is acceptable, then the gage is waterproofed and spliced to the signal cable.

PART 14

PART 14
Vibration Monitoring of Rotating Equipment in Nuclear Power Plants

1 INTRODUCTION

Existing standards provide rules for the proper use of vibration monitoring instrumentation, acceptance testing of equipment at the manufacturer's facility, and to some extent, *in situ* evaluation of mechanical vibration. There is, however, a need for guidance for *in situ* vibration monitoring of rotating equipment for the purpose of scheduling or extending maintenance periods. The intent of this Part is to fill that need. The main paragraphs of this Guide are as follows:

(a) Paragraph 4, Vibration Monitoring, describes periodic and continuous monitoring and important considerations that affect quality of acquired data.

(b) Paragraph 5, Establishing the Baseline, describes collection and use of baseline data.

(c) Paragraph 6, Establishing Vibration Limits, provides a procedure and criteria for determining when maintenance should be scheduled for rotating equipment.

(d) Paragraph 7, Data Acquisition, presents the recommended practices for installation of data acquisition instrumentation.

(e) Paragraph 8, Hardware, describes the various types of transducers and continuous monitoring systems and recommends the characteristics that should be considered when selecting transducers and related equipment.

(f) Paragraph 9, Diagnostics, provides guidelines for performing vibration analysis and identifying possible causes of increasing or excessive vibration.

1.1 Scope

This Part provides guidance for preservice and inservice vibration monitoring of rotating equipment used in light-water reactor (LWR) power plants. This Part recommends monitoring methods, intervals, parameters to be measured and evaluated, acceptance criteria, corrective actions, and records requirements.

1.2 Purpose

The purpose of this Part is to present guidelines for implementing a vibration monitoring program that will provide vibration data that can be used for the following:

(a) to compare the vibration level of equipment to equipment of the same type with similar mounting conditions or to establish vibration guidelines and standards

(b) to detect changes in an equipment's vibration level that indicate that the equipment is approaching an inoperable condition or when continued operation might damage the machine

(c) to assist in the development of a predictive maintenance program by providing the basis for appropriate scheduling of maintenance

2 DEFINITIONS

The following list of definitions is provided to ensure a uniform understanding of selected terms used in this Part:

absolute measurement: measurement of machine vibration relative to a fixed point in free space.

acceleration: a vector that specifies the time derivative of velocity.

amplitude: the maximum value of a quantity.

diagnostics: methods used to identify sources and/or causes of vibrations from data gathered using vibration-monitoring and analytical equipment.

displacement: a vector quantity that specifies the change of position of a body, or particle, with respect to a reference frame.

electrical runout: a source of error on the output signal of a noncontacting probe system resulting from nonuniform electrical conductivity/resistivity/permeability properties of the observed material or from the presence of a local magnetic field at a point on the shaft surface.

filter (electronic): a device for separating components of a signal on the basis of their frequency. It allows components in one or more frequency bands to pass relatively unattenuated and it attenuates components in other frequency bands.

frequency range: the frequency range over which the transducer (system) sensitivity does not vary more than a stated percentage from the rated sensitivity.

frequency response: the output signal expressed as a function of the frequency of the input signal. The frequency response is usually given graphically by curves showing the relationship of the output signal and, where applicable, phase shift or phase angle as a function of frequency.

in situ: in the natural or original installed (or operational) position.

natural frequency: frequency of free oscillation of a system.

noncontacting probe: a probe that has the capability to measure the distance between the probe face and a surface such as that of a shaft. Sometimes also referred to as proximity probe.

phase angle: the fractional part of a period through which a sinusoidal quantity has advanced as measured from a value of the independent variable as a reference.

relative displacement: the relative displacement between two points is the vector difference between the absolute displacement vectors of the two points.

resonance: occurs when a system is forced to oscillate at a natural frequency of the system.

root mean square: the root mean square (rms) value of a set of numbers is the square root of the average of their squared values.

sensitivity: the ratio of a specific output quantity to a specific input quantity.

transducer: a device that measures dynamic motion of a system and produces an electrical output signal with amplitude that is proportional to the motion measured.

velocity: a vector that specifies the time-derivative of displacement.

3 REFERENCES

3.1 Referenced Standards

The following is a list of standards referenced in this Part.

ANSI S2.17-1980, American National Standard Techniques of Machinery Vibration Measurement
Publisher: American National Standards Institute (ANSI), 25 West 43rd Street, New York, NY 10036

API 670-1976, Non-Contacting Vibration and Axial Position Monitoring System
API 678-1981, Accelerometer-Based Vibration Monitoring System
Publisher: American Petroleum Institute (API), 1220 L Street, NW, Washington, DC 20005-4070

ASME OM Code-1990, Subsection ISTB, Inservice Testing of Pumps in Light-Water Reactor Power Plants
Publisher: The American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016-5990; Order Department: 22 Law Drive, P.O. Box 2300, Fairfield, NJ 07007-2300

ISO 2041-1975, Vibration and Shock-Vocabulary
ISO 2372-1974, Mechanical Vibration of Machines With Operating Speeds From 10 to 200 Rev/s — Basis for Specifying Evaluation Standards
ISO 2373-1974, Mechanical Vibration of Certain Rotating Electric Machinery With Shaft Heights Between 80 and 400 mm — Measurement and Evaluation of the Vibration Severity
ISO 3945-1977, Mechanical Vibration of Large Rotating Machines With Speed Range From 10 to 200 Rev/s — Measurement and Evaluation of Vibration Severity In Situ
Publisher: International Organization for Standardization (ISO), 1 rue de Varembé, Case Postale 56, CH-1211, Genève 20, Switzerland/Suisse

Standards for Centrifugal, Rotary, and Reciprocal Pumps, 4th Edition
Publisher: Hydraulic Institute (HI), 9 Sylvan Way, Parsippany, NJ 07054

3.2 Referenced Publications

References listed below can be used as aids in developing or performing rotating equipment related vibration monitoring activities.

Bloch, Heinze P., "Practical Machinery Management for Process Plants, Vol. I, Improving Machinery Reliability," Gulf Publishing Co., Houston, Texas, 1983

"Computerized PPM Systems," *Compressed Air Magazine*, July 1984. pp. 21–26

Dodd, V. Ray, and East, John R., "The Third Generation of Vibration Surveillance," ASME paper presented at 37th Petroleum Mechanical Engineering Workshop and Conference, Dallas, Texas, September 1981

Gilstrap, Mark, "Transducer Selection for Vibration Monitoring of Rotating Machinery," *Sound and Vibration*, February 1984

Goldmen, Steve, "Periodic Machinery Monitoring: Do It Right," *Hydrocarbon Processing*, August 1984, pp. 51–56

Hewlett-Packard, "Dynamic Signal Analyzer Application-Effective Machinery Maintenance Using Vibration Analysis," Hewlett-Packard Application Note 243-1, 1983

Jackson, Charles, "The Practical Vibration Primer," Gulf Publishing Co., Houston, Texas, 1979

Maxwell, A.S., "Experience With Use of Vibration Standards," presented at 6th Machinery Dynamics Seminar, Sept. 22 and 23, 1980, National Research Council of Canada, Reprint by Bentley Nevada Corp., Minden, Nevada, NO. L0477-00, 1982

Mitchell, John S., "An Introduction to Machinery Analysis and Monitoring," Penn Well Book, Tulsa, Oklahoma, 1981

Mitchell, John S., "How to Develop a Machinery Monitoring Program," *Sound and Vibration*, February 1984

Sohre, John S., "Operating Problems With High Speed Turbomachinery, Causes and Correction," ASME paper presented at the ASME Petroleum Mechanical Engineering Conference, September 23, 1968, Dallas, Texas

Taylor, James I., "Determination of Antifriction Bearing Condition by Spectral Analysis," The Vibration Institute, Clarendon Hills, Illinois, 1978

Taylor, James I., "Identification of Gear Defects by Vibration Analysis," The Vibration Institute, Clarendon Hills, Illinois, 1979

4 VIBRATION MONITORING

4.1 Types of Monitoring

Vibration monitoring involves the measurement of overall vibration parameters (displacement, velocity, or acceleration) for which some evaluation can be made, either through comparison to a standard, a manufacturer's specification, or previously acquired data from the same or similar equipment. In its broader definition, vibration monitoring can include other related parameters such as thrust, position, or differential expansion. This Part provides for the periodic and continuous monitoring of rotating equipment. The relative advantages of each type of monitoring are listed in Table 1.

Periodic vibration monitoring is the process of measuring the vibration of equipment at fixed intervals of time or operating hours. Continuous vibration monitoring is the process of continuous 24 hr/day surveillance of the vibration of equipment. The monitored data can either be continuously recorded or monitored with respect to criteria and an alarm sounded if the criteria are exceeded.

4.2 Quality Considerations

Since the basic technique used to detect equipment deterioration is trend analysis, data should be taken in as consistent a manner as possible to ensure that detected changes in vibration are actually due to machine condition changes and not errors or variations of the data acquisition technique or variations in machine loading. A monitoring program that provides data accurate within ± 10% imposes the restriction that only changes in amplitude in excess of 20% can reliably be used to indicate a machine condition change. Some of the more important considerations that can affect the quality of acquired data are identified below.

4.2.1 Transducer Location. Tables 2 through 6 provide recommended locations for monitoring vibration levels of various types of rotating equipment. In applying these recommendations, each machine should be reviewed for such items as critical speed, mode shapes, seal, or special component protection, i.e., submerged transducers in vertical pumps. These locations and noted directions provide for shaft measurements near the bearings and bearing measurements on a line of action through the shaft center line. The locations of these measurements should be clearly marked and identified to ensure repeatability of location during successive measurements.

If the mounting is external to equipment components, measurements can be influenced by vibrations transmitted to the equipment housing from the surrounding environment (e.g., piping, foundation, adjacent machinery). Therefore, mounting location should be carefully selected so measurements will accurately reflect only vibration of the machine itself, with minimal outside influences.

4.2.2 Transducer Attachment. The method used to attach the transducer to the rotating equipment is one of the most important considerations for repeatable data. All transducer brackets and mount locations must be rigid for the frequency range of interest. Permanently attached transducers are preferred because they are not movable and any attachment errors are the same for all measurements. Other attachment procedures, such as hand held, magnetic base, adhesive mounting, etc., can have some amount of looseness. Looseness will reduce the high-frequency response and improperly transmit high- and low-frequency vibration to the transducer; it can create apparent vibration in the signal not present on the equipment.

4.2.3 Transducer Selection. The choice of transducer must be made considering a large number of factors depending on the individual equipment being monitored and the type of measurement desired. Tables B-1 through B-5 of Nonmandatory Appendix B list advantages and disadvantages of the five principal transducer types and their use. The transducer and data processing equipment should have a flat response over the frequency range of interest.

Displacement transducers should be used where relative displacements are critical such as when evaluating shaft vibration relative to bearing or seal clearance. Velocity probes should be used for low- or medium-frequency measurements such as shaft vibration via shaft riders and casing measurements. Accelerometers should be used for wide-band frequency measurements, in particular for high-frequency measurements such as impacts.

4.2.4 Data Processing Equipment. Data processing equipment should be selected that minimizes distortion

Table 1 Comparison of Periodic and Continuous Monitoring and Relative Advantages

Periodic Monitoring	Continuous Monitoring
1. Less capital investment	1. Provides primary machinery protection from catastrophic failure through local/remote annunciation and/or automatic machine trip and shutdown
2. Less data acquisition equipment maintenance	2. May provide earlier detection of impending mechanical problems
3. Less manpower to ensure calibration of data acquisition system	3. Tracks vibration over all operating conditions
4. More data can be obtained from a machine at relatively small increase in cost	4. Can be used with other data accumulation/reduction devices (computers, data loggers, etc.)
5. More measurement locations	5. Continuous severity assessment
6. More vibration units of measurement (displacement, velocity, or acceleration) available from a single transducer	6. Rate of increase of vibration more readily determined
	7. Abrupt changes such as blade loss can be more promptly recognized
	8. Fewer manpower requirements to acquire data
	9. Data obtained in a more consistent manner; location direction and transducer mounting are repeatable
	10. Fewer measurement errors

Table 2 Transducer Location Guidelines — Turbines

Location	Direction	Periodic		Continuous		Transducer Type	Evaluation Parameters
		Minimum	Recommended	Minimum	Recommended		
Shaft at each bearing	Horizontal		X		X [Note (1)]	Noncontacting probe	Relative displacement
	Vertical		X		X [Note (1)]	Noncontacting probe	Relative displacement
	Vertical	X		X		Shaft rider or combination	Absolute displacement
Shaft axial position				X	X	Noncontacting probe	Relative displacement
Bearing cap	Horizontal	X	X [Note (2)]	X	X	Accelerometer	Displacement or velocity
	Vertical	X	X [Note (2)]	X	X	Accelerometer	Displacement or velocity
	Axial	X	X [Note (2)]	X	X	Accelerometer	Displacement or velocity

NOTES:
(1) Transducer should be installed at 45 deg on either side of the vertical center line in plane of rotation.
(2) Useful for additional information purposes.

Table 3 Transducer Location Guidelines — Equipment With Antifriction Bearings

Location	Direction	Periodic		Continuous		Transducer Type	Evaluation Parameters
		Minimum	Recommended	Minimum	Recommended		
Each bearing housing	Horizontal	X [Note (1)]	X	X [Note (1)]	X [Note (1)]	Velocity or accelerometer	Velocity or accelerometer [Note (2)]
	Vertical		X			Velocity or accelerometer	Velocity or accelerometer [Note (2)]
	Axial		X			Velocity or accelerometer	Velocity or accelerometer [Note (2)]

NOTES:
(1) Should be horizontal or vertical, whichever is higher. Typically, horizontal is higher than vertical.
(2) Acceleration measurements (g's) tend to give better sensitivity when the failure model is characterized by high-frequency vibration.

Table 4 Transducer Location Guidelines — Horizontal Pumps — Fluid Film Bearings

Location	Direction	Periodic		Continuous		Transducer Type	Evaluation Parameters
		Minimum	Recommended	Minimum	Recommended		
Each bearing housing	Horizontal	X	X	X [Note (1)]	X [Note (1)]	Accelerometer or velocity	Velocity or displacement
	Vertical		X			Accelerometer or velocity	Velocity or displacement
	Axial		X			Accelerometer or velocity	Velocity or displacement
Shaft at bearing	Axial			X	X [Note (2)]	Noncontact probe	Displacement
Pump shaft	Vertical	X	X	X	X	Noncontact probe or shaft rider with accelerometer or velocity	Displacement
	Horizontal		X		X	Noncontact probe or shaft rider with accelerometer or velocity	Displacement

NOTES:
(1) Direction of highest vibration.
(2) Normally used on large pumps (reactor feed, recirculating pump, etc.).

of the input signals and extracts the meaningful parameters in a consistent, repeatable manner. Parameters to be considered in selecting processing equipment are as follows:

(a) Frequency response of the processing equipment should be flat over the frequency range of interest.

(b) Processing equipment should not modify the data by such things as filter ringing, inadequate data, sample size, or loss of transient data.

(c) Parameters (displacement, velocity, acceleration) should be selected to include the frequency ranges of importance. For example, acceleration and, to a lesser degree, velocity measurements tend to emphasize high frequency.

4.2.5 Parameters Measured. The selection of the parameter being measured is important for a proper analysis of the vibratory response of rotating equipment. For example,

(a) displacement measurements tend to emphasize response from low-frequency components. Such measurements should be used to determine low multiples of running speed components and subsynchronous vibration.

Table 5 Transducer Location Guidelines — Motor-Driven Vertical Pumps — Fluid Film Bearings

Location	Direction	Periodic		Continuous		Transducer Type	Evaluation Parameters
		Minimum	Recommended	Minimum	Recommended		
Top motor bearing	Vertical	X	X	X	X	Velocity or accelerometer	Displacement or velocity
	Horizontal H_1 [Note (1)]	X	X	X	X	Velocity or accelerometer	Displacement or velocity
	Horizontal H_2 [Note (2)]		X		X	Velocity or accelerometer	Displacement or velocity
Lower motor bearing	Vertical		X			Velocity or accelerometer	Displacement or velocity
	Horizontal H_3 [Note (3)]		X		X	Velocity or accelero-meter	Displacement or velocity
	Horizontal H_4 [Note (3)]		X			Velocity or accelerometer	Displacement or velocity
Pump shaft	Horizontal H_5 [Note (4)]	X	X	X	X	Noncontact probe or shaft rider with accelerometer or velocity [Note (6)]	Displacement
	Horizontal H_6 [Note (5)]		X			Noncontact probe or shaft rider with accelerometer or velocity [Note (6)]	Displacement

NOTES:
(1) H_1 is in the direction of maximum amplitude (if practical).
(2) H_2 is perpendicular to H_1.
(3) H_3 and H_4 are in the same direction as H_1 and H_2, respectively.
(4) Pump shaft at casing/seal penetration, H_5, direction of highest amplitude.
(5) Pump shaft at casing/seal penetration, H_6, perpendicular to H_5.
(6) Noncontact probe is for continuous monitoring; shaft rider is for periodic monitoring.

Table 6 Transducer Location Guidelines — Electric Motors

Location	Direction	Periodic		Continuous Recommended	Transducer Type	Evaluation Parameters
		Minimum	Recommended			
Bearing cap	Horizontal	X [Note (1)]	X	X [Note (1)]	Velocity or accelerometer	Displacement or velocity
	Vertical		X		Velocity or accelerometer	Displacement or velocity
	Axial		X		Velocity or accelerometer	Displacement or velocity

NOTE:
(1) Should be horizontal or vertical, whichever is highest. Typically horizontal is higher than vertical.

(b) velocity measurements can be advantageous for use over a wide frequency range (up to 1 kHz using velocity transducers or up to 5 kHz using accelerometers). They are able to reflect a wide range of problems and are generally accepted as the best measure of overall vibration severity, particularly when many frequency components are present. Since equipment failure is affected by both amplitude and number of cycles, velocity is a convenient measurement parameter.

(c) acceleration measurements tend to emphasize the higher frequency components of machine vibration. Hence, acceleration measurements may be most suitable for detecting high-frequency machine problems such as gear meshing and roller bearing defects.

4.2.6 Meter Reading Techniques. The general techniques for reading an instrument should be well understood by individuals using the equipment. Analog meters should be read only in the upper two-thirds of the meter range. Digital meters can be read throughout their entire range. The procedure for reading swings in meter indications should be defined. Root mean square (rms) amplitudes are useful for varying amplitudes but tend to mask impact signals. Conversely, a system that has fast enough response to measure impact signals may be inconsistently read by multiple operators. Where multiple operators are used to implement the monitoring program, use of an averaging type meter is recommended. The relationship between the normal rms signal value and peak value should be considered when comparing measurements to acceptance criteria.

4.2.7 Data Logging Techniques. Vibration data should be logged on a data sheet such as that in Fig. 1. The information on the data sheet should include an identification of the equipment to be monitored, a schematic figure of the equipment showing the measurement locations, the vibration analyzer used, and a listing of the data to be obtained during each surveillance (periodic or continuous). Also to be included are the operating parameters to be recorded. This particular data sheet is set up to record data for many surveillances.

Data should be logged in such a manner that inconsistent data can be identified as it is being taken. The data sheet should contain the previous data for immediate in-field comparison to new data. This will facilitate the taking and review of repeat measurements. The data sheet should also contain the vibration limits or other acceptance criteria to be used with each piece of equipment. When a computer system is employed to obtain data, the same data should be recorded.

5 ESTABLISHING THE BASELINE

5.1 Baseline Data

Baseline vibration data are those data obtained when the equipment is known to be operating acceptably. Subsequent measurements are compared to the baseline values to detect changes in the level of vibration of the rotating equipment. Baseline data must accurately define the acceptable vibration condition of the equipment under normal operating conditions. Baseline vibration data are established for new and overhauled equipment or equipment whose previous baseline data may have been affected by maintenance. If the equipment is normally operated in more than one mode (e.g., different speeds or loads), baseline data should be established for each mode.

Baseline vibration data should be obtained for all vibration parameters that are commonly used to define the equipment's vibration condition. The more comprehensive the initial definition of baseline, the greater the likelihood of properly detecting, diagnosing, and tracking the deterioration of the rotating equipment. The parameters commonly used to define a vibration baseline include the following:

(a) overall unfiltered amplitude (displacement, velocity, or acceleration)
(b) filtered running speed amplitude (displacement)
(c) filtered running speed phase
(d) frequency spectrum of vibration signals
(e) coastdown frequency response
(f) startup frequency response
(g) shaft orbit

5.1.1 The extent of the baseline signature determination should depend on such items as the following:

(a) importance of rotating equipment
(b) previous history of equipment
(c) analysis equipment available
(d) capabilities of personnel

The locations at which data are obtained need not and should not be limited to those locations that are to be periodically monitored as recommended in para. 4. It is recommended that the baseline be a comprehensive vibration analysis encompassing many more measurement points and directions than could reasonably be collected during periodic or continuous monitoring. After either continuous or periodic monitoring has established that a change in vibration level is taking place, a repeat of the methodology used for baseline analysis can help define the cause of the vibration change.

Operating data should also be taken to document the conditions under which the vibration was measured.

5.2 Methods to Establish Baseline

For new and overhauled equipment, there is often a wear-in period as illustrated in Fig. 2 and it is not uncommon to see a change in vibration level during the first few days or weeks of operation. Time should be allotted for wear-in before baselining. For equipment that has been operating for a significant period and monitored for the first time, machine vibration can exist anywhere on the vibration trend curve. Data taken for baseline should be taken in Zone 2 of Fig. 2. Periodic monitoring will establish the applicable zone. Figure 2 is an example vibration trend curve. The shape of the curve will tend to vary for different rotating equipment.

After monitoring has established that the equipment has reached an acceptable condition, full baseline data should be taken. Monitoring should then continue as originally planned. The initial data and baseline data should be compared to specified criteria to determine the acceptability of the equipment vibration levels. These data are the basis on which future equipment problems will be detected and diagnosed. They must be stored in a manner that is easily retrievable and secure.

Fig. 1 An Example of a Vibration Data Sheet

Sample Machine Diagram

Plant ____________________
Unit ____________________
Equipment (name/number) ____________________

Driver __________ Manufacturer __________
rpm __________ Hp __________ Amps __________
Coupling Type __________ Manufacturer __________

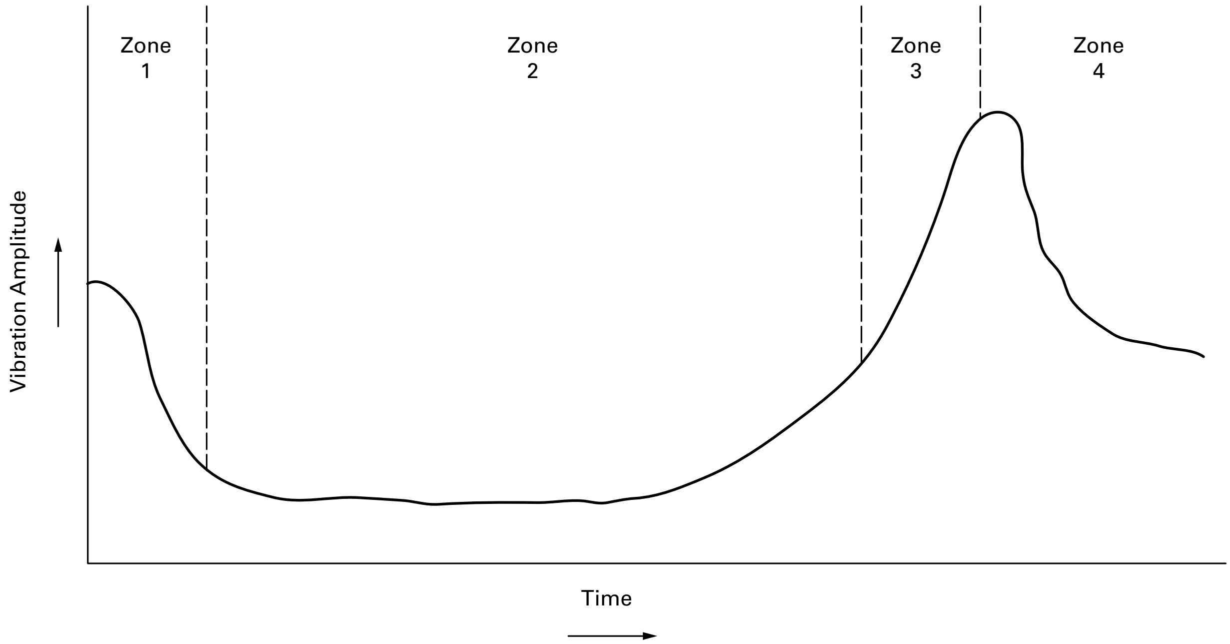
Driven __________ Manufacturer __________
rpm __________ Vibration Equipment Used __________

				Date									
	P	Limits											
Bearing	O S	Disp.	Vel.	Disp.	Vel.	Disp.	Vel.	Disp.	Vel.	Disp.	Vel.	Disp.	Vel.
	H												
	V												
	A												
Temperature, °F													
	H												
	V												
	A												
Temperature, °F													
	H												
	V												
	A												
Temperature, °F													
	H												
	V												
	A												
Temperature, °F													
Amps													
Suction, psig													
Discharge, psig													
ΔP													
Temperature, °F													
Load, MW													
Readings by													

Pickup point Plain bearing Coupling Antifriction bearing

Comments ____________________

Fig. 2 An Example of a Vibration Trend Curve



Zone 1: new machine roughness (wear-in period)
Zone 2: useful machine life
Zone 3: corrective action should be taken
Zone 4: component failure with either continuing increase or partial reduction of vibration

6 ESTABLISHING VIBRATION LIMITS

6.1 Purpose

The purpose of this paragraph is to establish the criteria for determining maintenance schedules for rotating equipment when guidance based on vibration monitoring is not provided by the manufacturer or needs to be enhanced. The criteria provides for the use of data acquired during either periodic or continuous monitoring. The interval of monitoring or data review will vary depending on the level of vibration observed, and the rate at which the vibration level is changing. The current condition of the equipment should be used to specify the frequency of periodic monitoring and minimum period for review of data obtained by continuous monitoring of equipment.

A primary consideration in developing the criteria is consistency with ASME OM Code, Subsection ISTB, which specifies three ranges of vibration: acceptable range, alert range, and required action range. The criteria are such that maintenance occurs prior to reaching the lower limit of the required action range.

6.2 Parameters

Standard practice is to process displacement in mils peak-to-peak, velocity in in./sec zero-to-peak, and acceleration in g's zero-to-peak, or rms. The method of processing peak-to-peak and zero-to-peak varies with the type of meter detector used and should be considered to ensure consistency of data.

6.3 Criteria

The vibration level for rotating equipment is divided into three ranges, an acceptable range, an alert range, and a required action range. Each of these ranges is defined by a vibration limit.

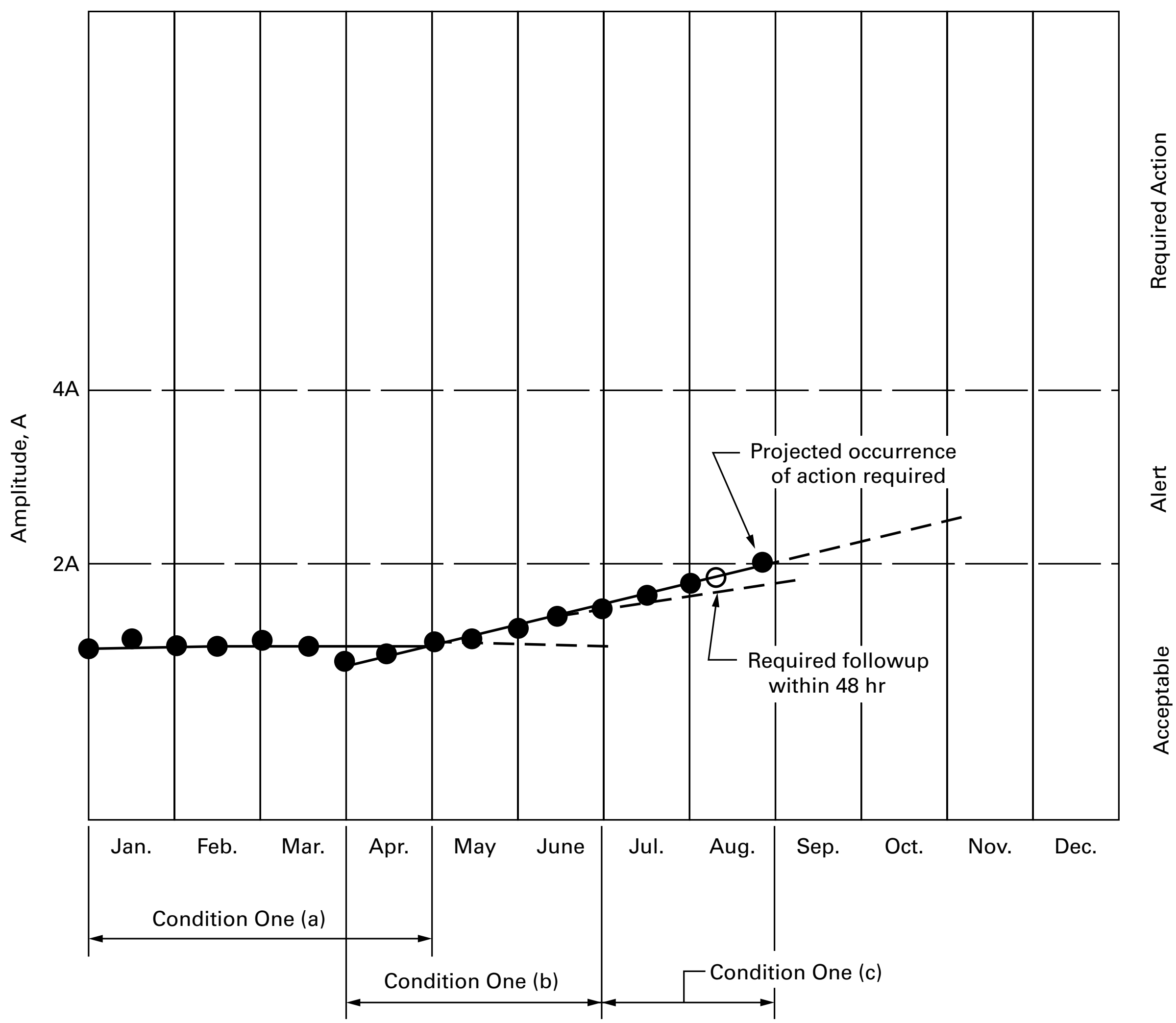
The recommended procedure for establishing limits for each of these ranges is as follows:

(a) Review the manufacturer's vibration criteria if available.

(b) If the manufacturer's vibration criteria are not available (pumps only) and ASME OM Code, Subsection ISTB applies, then Table ISTB 5.2-2 should be used to establish the limits for each of the ranges.

(c) When limits for each of the ranges cannot be established using either of the above methods, the technique

Fig. 3 Vibration Level Trend Plot of Condition One (For Defined Vibration Limits From Manufacturer's Data or Equivalent)



described in para. 5 should be used to determine the baseline vibration level. Structural analysis or engineering judgment should be applied in determining the upper limits for the acceptable range and the alert range. A factor of two increase over baseline vibration for the upper limit of the acceptable range and a factor of four increase over baseline vibration for the upper limit of the alert range are recommended maximum values.

The action required or recommended when equipment is operating in each of these zones depends on the rate at which the vibration level is changing. These actions are described below. Figures 3 and 4 depict two examples of results from a biweekly surveillance.

6.3.1 Condition One. Equipment vibration level is in the acceptable range according to the following:

(a) If there is no increase in level from previous data, then no action is required [Condition One (a)].

(b) If vibration is increasing, confirm rate within 48 hr.

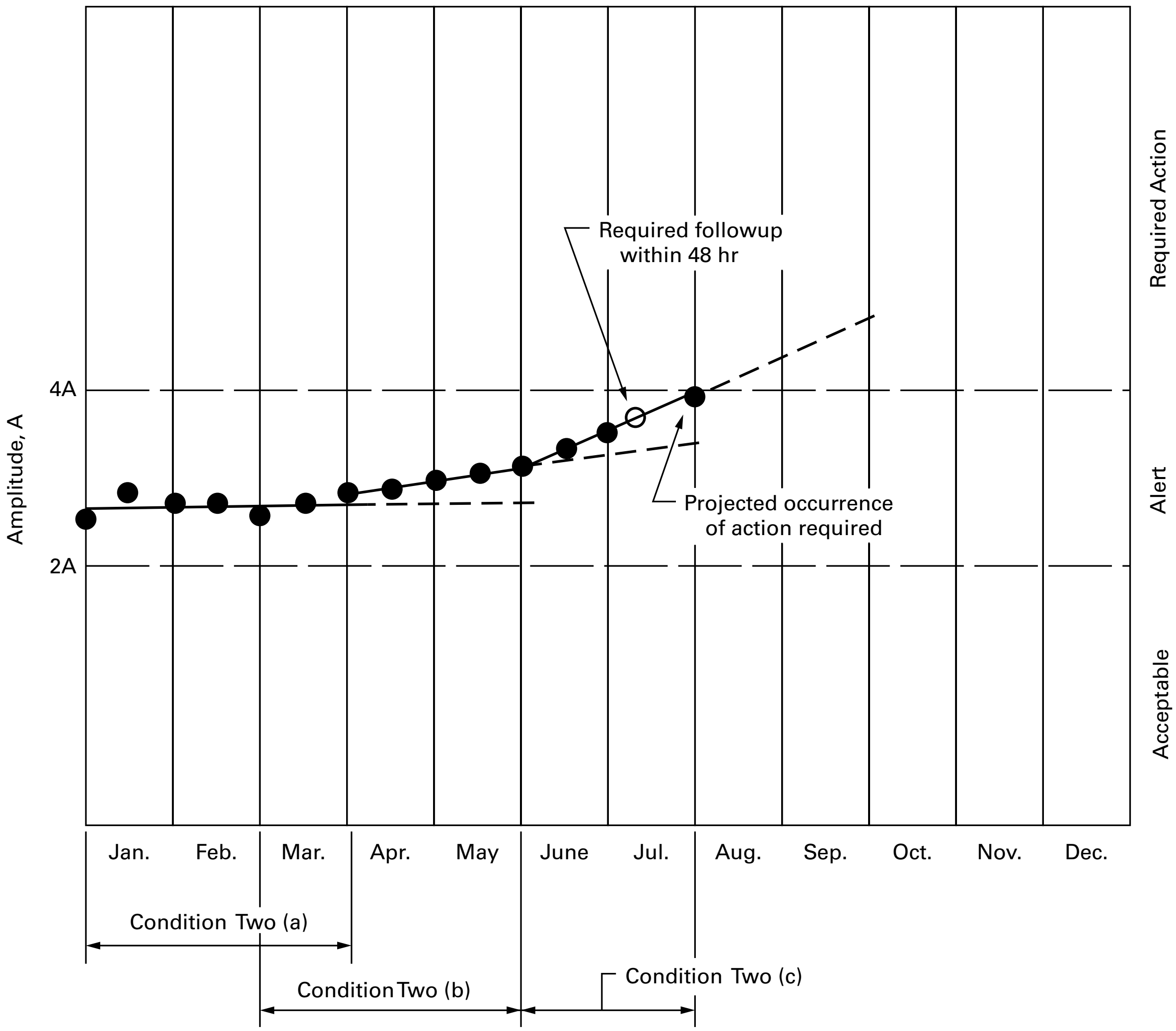
(1) If the rate of increase is linear and does not project to exceed upper limit of normal range before next scheduled surveillance, then no action is required [Condition One (b)].

(2) If the rate of increase is linear and projects to exceed upper limit of normal range before the next scheduled surveillance, schedule more frequent monitoring before upper limit will be reached [Condition One (c)].

(3) If the rate of increase is nonlinear, confirm the rate within 48 hr, schedule more frequent monitoring, and implement a diagnostics program.

(c) A decreasing trend in vibration amplitude is sometimes a symptom of equipment problems and diagnostics may be warranted.

Fig. 4 Vibration Level Trend Plot of Condition Two (For Defined Vibration Limits From Manufacturer's Data or Equivalent)



6.3.2 Condition Two. Current vibration level is in the alert zone according to the following:

(a) If there is no increase in level from previous data, continue to monitor biweekly [Condition Two (a)].

(b) If the level is increasing linearly but does not project to exceed the action level prior to the next scheduled review of the vibration level or scheduled maintenance, confirm the rate of increase within 48 hr and implement a diagnostics program [Condition Two (b)].

(c) If the level is increasing at a linear rate that projects to exceed the action level before the next scheduled surveillance or if the rate of increase is nonlinear, confirm the rate with more frequent readings and reschedule maintenance as required. Increase the frequency of monitoring to ensure that at least three data points are collected prior to rescheduled maintenance. A diagnostics program is recommended to define the problem and identify maintenance required [Condition Two (c)].

If a decrease in vibration level is observed, the biweekly monitoring rate should continue; detailed diagnosis is recommended.

7 DATA ACQUISITION

Instrumentation selection and use are key ingredients in data acquisition. The selection of instrumentation is primarily governed by the type of measurement to be taken (i.e., displacement, velocity, or acceleration), the type of equipment being monitored, the range of frequencies of interest and the environment in which the instruments must operate. Tables 2 through 6 recommend the type of measurement that should be used depending on the type of equipment being monitored. Nonmandatory Appendix A addresses instrumentation installation and calibration, pretest conditions, measuring and recording information, special considerations, and personnel.

8 HARDWARE

Selection of the proper transducer/measurement/monitoring combination is important for equipment protection and for obtaining an accurate measurement. Nonmandatory Appendix B provides guidance in selecting transducers and analysis equipment. Additional information can be found in the standards and publications referenced in para. 3.

9 DIAGNOSTICS

9.1 Purpose

This paragraph is intended as a guide to identify possible causes of equipment vibration. It is recommended that the user refer to the references listed in para. 3 for more details on causes of vibration.

Paragraph 4 suggests methods of formulating or collecting data based on what is suspected to be the cause of the problems and is not intended to be a recommendation of any particular data analysis equipment. In most cases, knowing frequency content and amplitude is sufficient for problem identification, with phase data being desirable for complicated vibration problems. It is recommended that individuals involved in diagnostics have, as a minimum, formal training in rotating equipment vibration analysis or the assistance of trained personnel to be most effective.

9.2 Troubleshooting

Table 7 lists some potential causes of machinery vibration and what is typically observed in terms of frequency content and direction of the vibration, along with appropriate remarks. There are several charts of this type available in the references listed in para. 3, which the user may find useful. These charts are no substitute for experience and engineering judgment.

Table 7 Vibration Troubleshooting Chart

	Frequency of Vibration (Hz = rpm/60)	Direction	Remarks
Rotating members out of balance	1 × rpm	Radial	The most common cause of excess vibration in equipment
Misalignment and bent shaft	Usually 1 × rpm; often 2 × rpm; sometimes 3 × and 4 × rpm	Radial and Axial	The second most common fault
Rubs	1 × rpm and possible higher multiples	Radial	A common cause of excess equipment vibration
Damaged rolling element bearings (ball, roller, etc.)	Impact rates for the individual bearing components; also, vibrations at very high frequencies (20–60 kHz)	Radial	Uneven vibration levels, often with shocks
Journal bearings loose in housings	Subharmonics of shaft rpm; exactly $\frac{1}{2}$ or $\frac{1}{3}$ rpm	Primarily radial	Looseness may only develop at operating speed and temperature (e.g., turbomachines)
Oil film whirl or whip in journal bearings	Less than $\frac{1}{2}$ shaft speed	Primarily radial forward whirl	Vertical and lightly loaded horizontal equipment
Hysteresis whirl	Shaft critical speed	Primarily radial	Vibrations excited when passing through critical shaft speed are maintained at higher shaft speeds; can sometimes be cured by checking tightness of rotor components
Damaged or worn gears	Tooth-meshing frequencies (shaft rpm × number of teeth) and harmonics	Radial and axial	Sidebands around tooth-meshing frequencies indicate modulation (e.g., eccentricity) at frequency corresponding to sideband spacings; normally detectable only with very narrow band analysis
Mechanical looseness	2 × rpm, or 1 × rpm if loose part becomes rotating unbalanced	Radial and axial	Also sub- and interharmonics and for loose journal bearings
Faulty belt drive	1 ×, 2 ×, 3 ×, and 4 × rpm of belt, usually 2 ×	Radial	
Unbalanced reciprocating forces and couples	1 × rpm and/or multiples for higher order unbalance	Primarily radial	
Electrically induced vibrations	1 × rpm or 1 × or 2 × synchronous frequency	Radial and axial	Should disappear when power is turned off
Shaft position changes	All	Radial and axial	Indicates bearing load changes, external forces, and process upsets

PART 14
NONMANDATORY APPENDIX A
Instrumentation Selection and Use

A-1 INSTALLATION OF TRANSDUCERS

A-1.1 Mounting Techniques

Monitoring may be accomplished using either permanently or temporarily mounted transducers. Permanently mounted transducers using manufacturer's specifications are recommended. When using temporarily mounted transducers, care should be taken to follow the special considerations within this Part. The principal effects of the different mounting techniques are to limit the useful frequency range of the transducer, introduce erroneous signals, and reduce reproducibility of the data. Most transducers will amplify signals near the mounted resonance of the transducer.

A-1.1.1 Stud Mounting. Stud mounting is a reliable technique for fastening transducers directly to a surface for measurement. The stud may be fastened to a surface by drilling and tapping or by welding or brazing. Care should be taken to mount the transducer flatly without overhang or surface discontinuity. Suggested mounting techniques supplied by the transducer manufacturer generally provide the desired accuracy and prevent possibilities for transducer damage. Isolation pads are available for electrical insulation when necessary.

A-1.1.2 Hand-Held Measurement. For most periodic vibration checks, a hand-held transducer without extension probe is generally satisfactory. The transducer should be held against a flat surface with its entire face in contact with the surface. Care should be taken to apply only enough pressure to prevent chattering of the transducer on the surface, which can produce a false high-frequency vibration indication. Extension probes should only be used for convenience in reaching out-of-the-way measurement points. Generally, the shorter the probe the better, especially when measuring higher vibration frequencies.

A-1.1.3 Magnetic Transducer Holders. The magnetic holder should provide acceptable results when applied to a reasonably flat, smooth, clean, unpainted surface. Paint, grease, and dirt reduce magnet holding power, thus reducing maximum usable frequency range and introducing the possibility of chatter or rocking.

A-1.1.4 Bonded Mounting. When a more permanent attachment cannot be used, transducers can be installed on structures using adhesives such as epoxy. The adhesive must be specified for the environment in which it is to operate (e.g., temperature or radiation) and must not be detrimental to the surface of the equipment. Preferably, this should be considered a short-term installation with the transducer eventually being more permanently secured with stud or bolt mounting.

A-1.1.5 Quick-Release Mounting. Quick-release mounting provides a positive locking mechanism for periodic monitoring purposes. The usable frequency range and repeatability are also improved when compared to hand-held or magnetic holder methods.

A-1.2 Types of Measurement

A-1.2.1 Bearing Housing Absolute Measurement. Bearing housing absolute measurement can be accomplished using either velocity or accelerometer pickups and is defined as the vibratory motion of the housing in free space.

A-1.2.2 Shaft Absolute Measurement. Shaft absolute measurement is defined as the vibratory motion of the shaft in free space and can be accomplished using the following measurement techniques:

(a) combination shaft probe (see Nonmandatory Appendix B)
(b) shaft riders (see Nonmandatory Appendix B)
(c) shaft stick (see Nonmandatory Appendix B)

A-1.2.3 Shaft Relative Measurement. Measurement of shaft relative vibration can be accomplished using noncontacting probes mounted to the machine support structure. Ideally, the support member should be the bearing, bearing housing, or a direct bearing support element. If there is not looseness between the bearing and bearing housing, this yields a measurement of shaft vibration relative to the bearing clearance. Typically, probes are installed adjacent to the bearing, but installations through the bearing itself are also possible.

Care should be taken to ensure that the probe senses a nonplated, journal-quality shaft surface, free from mechanical and electrical runout in excess of 0.25 mils. If runout criteria cannot be met, this should be compensated for electronically. Runout should be determined on a fully heat-soaked machine. When mounting brackets are required to fix the probe to the machine support structure, the bracket and probe resonant frequency should be well above the range of expected machine vibration frequencies.

A-2 CALIBRATION

Instrumentation used for periodic monitoring should be calibrated in accordance with the Owner's quality assurance program. Recommended calibration intervals are prescribed below.

Equipment	Interval
Accelerometers, noncontacting probes	1 year
Velocity probes	6 months
Meters and instruments	1 year

New or repaired instruments should be calibrated prior to use. A system of records should be established to identify each instrument and calibration date and each instrument may contain an attached tag or sticker identifying the date of last calibration and expiration date.

A-3 PRETEST CONDITIONS

Equipment monitoring should take place with equipment operating conditions identical to those for which baseline data were accumulated. Vibration levels are generally responsive to change in equipment operating conditions. These conditions include pump flow and fluid temperature, motor amperage, bearing and lubricating oil temperature, and rotating speed. Efforts should be made to match machinery operating conditions each time data are gathered.

A-4 MEASURING AND RECORDING INFORMATION

Periodic monitoring data may be gathered using permanently installed or portable instrumentation. Data must be obtained at previously established measurement points on each piece of rotating equipment. For trending, data sheets should be used for equipment identification, discussion of special conditions or machine setup, and tabulation of data. A typical data sheet is shown in Fig. 1. Alternately, microprocessing or storage devices capable of providing the same results are also acceptable.

A-5 SPECIAL CONSIDERATIONS

A-5.1 Natural Frequency

The natural frequency of the transducer or transducer-probe combination should be determined and accounted for in the analysis of data.

A-5.2 Magnetic/Electrical Interference

Alternating magnetic fields, inherent with AC monitors or generators, can interfere with the output of some vibration transducers. This can be evaluated by suspending the transducer in the area where the data are normally taken. No significant signal should be measured when the machine is running. If magnetic/electrical interference exists, shielding should be considered where recommended by the manufacturer. Otherwise, an alternate measurement system should be tried.

Care should also be taken to ensure that instrumentation systems do not cause ground loops emitting 60 Hz signals.

A-5.3 Environment

Care should be taken to select vibration instruments suitable for use in harsh or hazardous environments. Harsh or hazardous environments include, but are not limited to, those areas where instrument reliability could suffer or be lost due to heat, dust, moisture, corrosives, or radiation. In addition, operator safety should not be jeopardized by toxic gases, radiation, or vibration instruments igniting combustibles.

A-6 PERSONNEL

Personnel used for gathering of periodic data should be trained and knowledgeable in the use of vibration instrumentation as applicable to specific policies, procedures, and quality assurance requirements.

PART 14
NONMANDATORY APPENDIX B
Transducers and Analysis Equipment

B-1 TRANSDUCERS

(a) There are three basic parameters (displacement, velocity, and acceleration) commonly measured for equipment vibration applications. The selection of the transducer type used to make these measurements is governed by the following:

(1) type of monitoring program being conducted
(a) periodic
(b) continuous
(2) type of bearing
(a) sleeve
(b) rolling element/antifriction
(3) bearing stiffness
(4) transmissibility
(5) foundation/pedestal flexibility

(b) Periodic monitoring programs usually require portable instrumentation to measure casing or bearing cap vibrations. Care needs to be taken to ensure that readings are taken on a structural part of the machine such as the equipment frame or bearing cap.

(c) Continuous monitoring transducers are permanently mounted to the machines. Tables 2 through 6 provide the guidelines to be considered when selecting which type of transducer to use. Care should be taken to ensure that the transducer and its installation do not significantly alter machine natural frequency.

(d) Considerations in selecting a transducer for a particular job include the following:

(1) sensitivity mV/g
(2) frequency range
(3) size
(4) temperature range
(5) amplitude range
(6) radiation
(7) mounting method
(8) accuracy

(e) The advantages and disadvantages of each transducer type are given in Tables B-1 through B-5.

B-1.1 Noncontact Transducer

A common displacement transducer for rotating equipment monitoring is the noncontacting eddy probe system. This is an electrical device that measures the relative motion between the probe mount (bearing) and target material (shaft). These solid state devices have no moving parts and produce an output signal proportional to component position (DC level) or change in position (AC signal) within a bearing for monitoring or diagnostics purposes.

Standard noncontacting probes that monitor equipment vibration normally have a linear range from 10 mils to 90 mils with either a 100 mV/mil or 200 mV/mil sensitivity and a 0 kHz to 10 kHz frequency range. The shaft material absorbs energy from the magnetic field radiating from the probe. The closer the shaft gets to the probe, the more energy that is removed from the magnetic field, resulting in a reduced output from the oscillator/demodulator and producing a varying voltage proportional to the changing gap between the shaft and the probe. This signal corresponds to the relative motion between the shaft and the bearing. Due to the different electrical properties of different materials the probes must be calibrated for the particular material being observed.

Runout can cause errors in the vibration signal from a noncontacting probe. Mechanical runout caused by misalignment, eccentricities of the shaft, or other surface irregularities can be removed by using established techniques.

Electrical runout caused by factors such as localized carbon or chrome in the shaft material, forging methods, or shaft spraying requires machining of the shaft surface or electronic removal of the runout signal.

B-1.2 Velocity Transducers

Velocity transducers are normally electromechanical devices that use either a reference coil and movable magnet or reference magnet and movable coil to produce an output signal proportional to the velocity of a vibrating component. Mechanical velocity transducers are self-generating devices that develop signals, usable for rotating equipment monitoring or diagnostics. The transducer uses a spring-mass damper system to produce a very low resonance frequency.

This transducer is an electromechanical device that is subject to wear, sticking, corrosion, and stray electrical fields from motors or generators. The standard transducer's damping medium normally limits usable temperatures to about 250°F with output sensitivities from 100 mV/in./sec to 1,000 mV/in./sec. Standard usable frequency range is from 10 Hz to 1,000 Hz.

Table B-1 Noncontacting Displacement Probes — Probe Advantages Versus Disadvantages

Advantages	Disadvantages
1. Measures directly the dynamic motion (relative to point of probe attachment) of the shaft, which is the source of vibration for the most common (frequently occurring) machine malfunctions, such as imbalance, misalignment, rubs, bearing instability, etc.	1. Runout (electrical and mechanical); dependent upon homogeneous shaft material, high-quality shaft surface finish, free from scratches, rust, corrosion, chrome plating, etc., and localized (spot) magnetic fields
2. Measures average rotor position (relative to bearing or housing attachment point) within the bearing clearance, an important indicator of steady-state undirectional preloads on the rotor, such as from misalignment, fluidic, or aerodynamic influences, etc.	2. Sensitive to some shaft materials (metallurgical content); may require special calibration to specific material
3. Ease of calibration; only static calibration required using spindle micrometer and digital voltmeter	3. Requires external DC power source
4. Same type of transducer can also be used for axial thrust position, rotor eccentricity (bow), rotor speed, phase angle (keyphasor reference), and differential expansion measurements	4. Can be difficult to install on some machine (bearing) designs
5. Measures directly in engineering units of displacement	5. Usually difficult to install quickly on a temporary basis; probes should be permanently installed even for periodic measurements
6. Good signal-to-noise ratio; high-level, low-impedance output can be separated from monitor by over 1,000 ft (300 m)	
7. Broad frequency response, from 0 Hz (DC or static position) to 10 kHz	
8. Solid-state for extended reliability (no moving parts)	
9. Modular system design which spreads the cost to cover replaceable components	

Table B-2 Velocity Transducers — Transducer Advantages Versus Disadvantages

Advantages	Disadvantages
1. Ease of installation (mounted to machine externals, e.g., bearing housing)	1. Provides limited information about shaft dynamic motion, requires that the machine have low mechanical impedance
2. Strong signal in the midfrequency ranges (15 Hz to 1 kHz)	2. Mechanical Design (spring/mass/damper) a. Degrades somewhat over a period of time under normal use b. Cross axis sensitivity problems at high temperatures c. Rather large and heavy d. Not extremely rugged
3. Seismic type transducers are self-generating, with no external power source required; accelerometer types are not self-generating	3. Unit construction (any transducer fault requires replacement of complete transducer assembly)
4. Can measure shaft absolute (relative to free space) vibration when mounted to a rider (permanent installations) or "fishtail" (temporary installations)	4. Difficult calibration; requires removal from the machine and use of a shaker table
5. Adequate frequency response for overall evaluation of machines in the midspeed range	5. Amplitude and phase errors introduced at low frequencies
6. Can be temporarily installed with reasonable success using a magnetic base	
7. Models are available for moderately high temperature	
8. Velocity is relatively easy to integrate to displacement	

Table B-3 Accelerometers — Transducer Advantages Versus Disadvantages

Advantages	Disadvantages
1. Ease of installation (mounted to machine externals, e.g., bearing housing) in case-mounted applications (however, refer to item 3 under "disadvantages")	1. Provides only limited information about shaft dynamic motion (for overall evaluation of machine vibration); requires that the machine have low mechanical impedance
2. Very useful for high-frequency measurements, above 2 kHz	2. Susceptible to noise resulting from method of attachment or poor contact to machine housing; requires deliberate effort to achieve effective installation. Frequency response limited when used with a temporary mounting, even more so when hand held
3. Effectively no moving parts; good reliability	3. Unit construction means that any transducer fault requires replacement of complete transducer assembly
4. Models are available for high-temperature applications, beyond the range of other transducers	4. Difficult calibration; requires removal from the machine and use of a shaker table
5. Relatively light weight	5. Difficult to use for some low-speed machines and other low-frequency applications, since low-acceleration levels produce signals which are typically not far above noise floor (poor signal to noise ratio)
6. Broad frequency response	6. Double integration to displacement for overall evaluation of machinery vibration is susceptible to electrical noise and electronic integration problems, particularly in the low-frequency region
	7. Sometimes requires filtering in the monitor, and the filters must be individually determined for each machine case
	8. Somewhat sensitive to damage (requiring replacement) due to harsh impact (dropping on concrete, etc.), particularly in the nonsensitive axis

Table B-4 Combination Probe Attached to Bearing Housing — Transducer Advantages Versus Disadvantages

Advantages	Disadvantages
1. Incorporates all the advantages of the noncontacting probe	1. Phase and amplitude errors at low frequencies (less than 1200 cpm) in absolute measurements which must be corrected by electronic or manual (graphic) means for velocity transducers
2. Provides four pieces of information allowing connection to a wide variety of diagnostic instruments for machine problem investigation: a. shaft absolute motion b. shaft relative motion c. bearing housing motion d. average shaft position in bearing clearance	2. Mechanical design of seismic element-performance will deteriorate over a period of time in normal use
3. Broad frequency response: 4.5 Hz to 1 kHz for absolute measurements, DC to 10 kHz for relative measurements	3. Disadvantages listed in Table B-1 also apply
4. Provides measurement of shaft motion relative to bearing and bearing motion relative to free space; and, therefore, indicates mechanical impedance of the system-actual impedance from shaft through oil film, through the bearing, the bearing support, and out to the location of the seismic transducer	4. Disadvantages listed in Tables B-2 and B-3 apply depending upon transducer used

Table B-5 Shaft Rider — Transducer Advantages Versus Disadvantages

Advantages	Disadvantages
1. Provides shaft absolute dynamic motion directly 2. Self-generating transducer, e.g., does not require power supply	1. Contacting: wear can occur between tip and shaft 2. Limited frequency response: 10 to 120 Hz typically; limited shaft slow roll (bow or eccentricity) measurement 3. Must be located in lubricated area 4. May, under extreme cases, damage shaft or bearing 5. Rider may "hydroplane" on oil film 6. Friction in shaft rider guide can cause errors in output because rider may not exactly follow shaft motion 7. Moving parts: seismic element, slider, spring, rider tip on shaft; performance will deteriorate in time under normal use 8. Slip bounce, squeal, or chatter can occur if proper lubrication and shaft surface finish are not maintained 9. Errors due to mechanical runout 10. Phase and amplitude errors at low frequencies (caused by the seismic element) and at higher frequencies (caused by the mechanical riding system)

An alternative method of developing a velocity signal is to perform integration on a piezoelectric accelerometer signal. This extends the usable frequency range of the velocity transducer.

B-1.3 Acceleration Transducer (Accelerometer)

An accelerometer is a solid state device that normally uses a piezoelectric crystal to develop an output signal proportional to the acceleration of a vibrating component. Accelerometers for machinery applications normally use internal amplifiers and external power to develop a signal usable for machinery monitoring or diagnostics.

Because of their small mass, accelerometers have a wide frequency range (2 Hz to 5,000 Hz) and large dynamic range (90 dB). The accelerometer is solid state, has low mechanical wear, and requires very little calibration with age. However, the internal electronics limit standard accelerometer usage to temperatures below 250°F. For applications above 250°F, accelerometers with external electronics and power supplies are also available.

Typical sensitivities range from 10 mV/g to 100 mV/g (1 g = 386.1 in./sec/sec) and provide strong high-frequency signals.

B-1.4 Combination Transducers

A combination transducer consists of a noncontacting displacement transducer mounted to the bearing housing (see para. B-1.3) to measure shaft-relative vibration and a seismic probe to measure the bearing housing vibration. The signal from the seismic probe is electronically integrated to displacement and combined with the noncontacting transducer output to provide a measurement of shaft absolute vibration (relative to free space) for monitoring or diagnostics. Combining of the two signals is usually accomplished by the readout/monitoring equipment.

Either an accelerometer or a velocity transducer can be used to measure the bearing housing vibration. Electronics are required to compensate for the phase lags associated with velocity transducers (see para. B-1.2).

When using this technique, caution should be exercised to ensure that the seismic probe actually measures the same motion as the noncontact probe support. Erroneous signals have been developed by not installing the seismic probe directly in line and in the same plane as the eddy probe. Erroneous signals have also been generated by not installing the seismic probe rigidly to the noncontact probe support.

B-1.5 Shaft Rider

The shaft rider is a mechanical spring-loaded device that physically rides on the shaft surface. A seismic transducer attached to a rod converts the rod's mechanical motion into an output signal that is proportional to the shaft absolute radial motion. The shaft rider tip is constructed of a material softer than the shaft material yet rigid enough to transmit the shaft's vibration to the seismic transducer. The surface on which the shaft rider rides must be well lubricated (to prevent chatter), smooth, and free from mechanical runout and scratches.

Since the shaft rider mechanically follows the radial shaft motion, its applications are physically limited by shaft speed, circumference, tip material, and amount of lubrication. Most shaft riders are further limited by the transducer system response to less than 200 Hz.

B-1.6 Shaft Stick

A shaft stick is a stick or paddle on which a transducer is mounted and held against a smooth, rotating part of the shaft for measuring absolute motion. Care should be taken in each instance to eliminate chattering. Consider items such as shaft smoothness and geometry, shaft speed, and such. Hand-held sticks should be coated with a medium weight lubricating oil in contact with the shaft, and the stick material should be sufficiently soft to avoid shaft damage. It may be desirable to polish the shaft damage. It may be desirable to polish the shaft with emery cloth prior to taking readings. The shaft stick should ride freely on the shaft and not be jammed into position.

B-1.7 Once Per Turn Phase Angle Reference

There are usually three ways of obtaining a once per turn phase angle reference; they are as follows:

(a) a noncontacting probe observing a notch or projection located on the radial or axial shaft surface

(b) a magnetic transducer observing a notch or projection located on the radial or axial shaft surface

(c) an optical transducer observing an optical discontinuity on the radial or axial surface of the shaft

B-2 CONTINUOUS VIBRATION MONITORING INSTRUMENTS

B-2.1 Vibration Switch

A vibration switch is an integral seismic transducer and monitoring device that senses the structural vibration level of a mounting surface and provides a contact actuation when vibration exceeds a preset level.

B-2.2 Nonindicating Monitor

A nonindicating monitor accepts a vibration signal from a transducer and performs vibration detection and signal conditioning. It provides a DC voltage proportional output and contact closure where the vibration exceeds a preset level.

B-2.3 Indicating Monitor

Indicating monitors provide the same functions as nonindicating monitors plus local metering and local indication. Some self-checks are performed to ensure proper monitoring system operation.

B-2.4 Diagnostic Monitor

Diagnostic monitors use transducer analog signals as input to computer or microprocessing systems. The computer or microprocessing system uses the analog signal and provides digital data storage, trending, spectrum analysis, and such.

B-3 PERIODIC ANALYSIS INSTRUMENTATION

B-3.1 Go/No Go Meter

A go/no go meter provides a nondimensional indication of vibration severity.

B-3.2 Overall Level Meter

An overall level meter provides a dimensional value of overall unfiltered vibration amplitude.

B-3.3 Tunable Filter

A tunable filter provides indication of vibration amplitude at a selected frequency or over a frequency range. Output to a stroboscopic light can be used for phase angle measurement.

B-3.4 Oscilloscope

An oscilloscope provides time domain and orbital displays of vibration signals.

B-3.5 Fast Fourier Transform Analyzer

A Fast Fourier Transform Analyzer (FFT) is an instrument that separates a complex signal into its frequency and amplitude components in a simultaneous display.

B-3.6 Portable Integral Memory Data Acquisition and Playback Instrument

An integral memory data acquisition and playback instrument is a transportable instrument used to acquire and store vibration signals into internal memory. These signals can then be transferred to a host computer for storage and data manipulation.

B-3.7 Tape Recorders

AM or FM tape recorders are used for storing analog vibration data for subsequent analysis by the instrumentation described above.

PART 17

PART 17
Performance Testing of Instrument Air Systems in Light-Water Reactor Power Plants

1 INTRODUCTION

This Part was developed by the ASME Committee on Operation and Maintenance, Subcommittee on Mechanical Equipment and Systems for the purpose of providing the nuclear industry with a guide for preoperational, performance, and postmaintenance or -modification inspection and testing of instrument air systems. This Part contains recommendations for methods and frequency of specified tests. The Appendices provide recommendations for baseline testing, identify recommended system design considerations, and provide guidance for assessment of problems.

1.1 Scope

This Part provides guidance for preservice and inservice testing to assess the operational readiness of certain instrument air systems used in light-water reactor (LWR) power plants.

The instrument air systems covered are those that supply air to systems 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.

This Part recommends test methods, test intervals, parameters to be measured and evaluated, acceptance criteria, corrective actions, and records requirements.

2 DEFINITIONS

The following list of definitions is provided to ensure a uniform understanding of selected terms used in this Part:

aftercooling: process of removing heat and condensed water from compressor discharge air.

afterfilter: filter located downstream of compressed air dryers, typically to protect downstream equipment from desiccant dust or other particulates.

air receiver recovery rate: time required to increase air receiver pressure from a low value to a predetermined higher value while maximum air demand (usage) is imposed on the air system.

approach temperature: difference between exit air and cooling medium inlet temperatures.

automatic drain: device that automatically discharges condensate from a moisture separator, typically by action of a float device or timer.

compressed air dryer

desiccant: compressed air dryer that uses a desiccant to remove moisture.

refrigeration: compressed air dryer that uses mechanical refrigeration to remove moisture.

compression ratio: ratio of absolute discharge pressure to absolute inlet pressure.

dew point: temperature at which water vapor begins to condense into liquid.

dew point, atmospheric: dew point of air at atmospheric pressure.

dew point, pressure: dew point of air at operating pressure.

discharge pressure: total pressure (static plus dynamic) at the discharge flange of a compressor.

distribution network: piping and components that supply compressed air to end-use devices.

free air: volume of air at atmospheric conditions at a specific location; may refer to displacement or capacity.

free air capacity: compressor discharge air flow rate expressed as volume at conditions of temperature and pressure prevailing at the compressor inlet.

intercooling: process of cooling air between stages or stage groups of compression.

moisture separator: device that removes liquid from an air stream.

operational capacity: air flow required to maintain satisfactory operation of an instrument air system.

partial pressure: pressure that each constituent of a gas would exert if it alone occupied a given volume.

prefilter, coalescing: filter that removes water and oil aerosols by combining the aerosols into larger droplets for easy removal (typically installed ahead of a compressed air dryer).

purge flow: desiccant regeneration air flow.

receiver (air): pressure vessel that contains a volume of air or gas at an elevated pressure, as a reservoir to avoid compressor short cycling, which collects residual condensate and oil droplets and reduces pressure fluctuations in an air system.

regeneration (reactivation): process of restoring desiccant capacity.

relative humidity: ratio of the partial pressure of water vapor to the water vapor saturation pressure at the ambient temperature of the mixture.

special service accumulator: backup air reservoir located near equipment, used to supply compressed air upon loss of the normal source.

standard air: air at a temperature of 68°F (20°C), pressure of 14.7 psia [101.3 kPa (absolute)], and relative humidity of 36%.[1]

3 REFERENCES

The following documents contain information essential to understanding instrument air system operation and should be used as companion documents to this Part.

When documents are referenced in this Part, their revision date is shown in this paragraph.

ASME PTC 9-1970 (R1992), Displacement Compressors, Vacuum Pumps, and Blowers

Publisher: The American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 1001-5990; Order Department: 22 Law Drive, P.O. Box 2300, Fairfield, NJ 07007-2300

ISA S7.0.01-1996, Quality Standard for Instrument Air

Publisher: Instrument Society of America (ISA), 67 Alexander Drive, Research Triangle Park, NC 27709

4 GENERAL SYSTEM DESCRIPTION

For the purposes of this Part, the instrument air system extends from the compressor inlet air filter to, but not including, the end-use device or system of devices (e.g., instrument, equipment prime mover).

Figure 1 shows a typical flow diagram of an instrument air system and identifies major components. For this Part, an instrument air system is treated as three subsystems as follows:

(a) compressor and receiver
(b) dryer and filters
(c) distribution network

The compressor and receiver subsystem typically consists of compressor inlet filter, compressor, aftercooler, receiver, and associated drain traps and pressure-relief valves. The compressor and receiver subsystem compresses ambient air to increase pressure to system design values and transports it to a receiver where it is stored for system demand surges. This subsystem supplies pressurized, cooled, wet air to the dryer and filter subsystem.

Compressed air is next processed by the dryer and filter subsystem of the instrument air system to remove moisture, oil, and particulate contamination. Typically, this subsystem consists of a coalescing prefilter that removes oil, liquid water, and particulates; an air dryer that removes water vapor; and an afterfilter that removes particulates. The dryer and filter system supplies clean, dry air to the distribution network.

The distribution network consists of the main air headers, branch lines, and accumulators that supply compressed air to end-use devices but does not include pressure regulators. The distribution network must not contaminate the air supply, induce excessive pressure drops, or leak excessively.

5 TESTING

Instrument air system performance testing separately addresses the compressor and receiver, the dryer and filter, and the distribution network. Dividing the instrument air system this way allows the compressor, receiver, dryer, and filters to be tested at their design capacity, and the distribution network to be tested at its operational capacity.

The distribution network test is also an operational capacity functional test for the instrument air system. Overall acceptance criteria are satisfied by demonstrating that the air compressors will operate at design capacity, the air dryers and filters will operate at design capacity, and the distribution network performs its function without contaminating the air supply, inducing excessive pressure drop, or leaking excessively.

5.1 Owner's Responsibilities

The Owner should

(a) identify components with specific operability requirements (e.g., check valves, service air cross-ties) and develop test procedures to verify proper operation

(b) document deviations from recommended test conditions in a test report

(c) evaluate test results for conformance with acceptance criteria

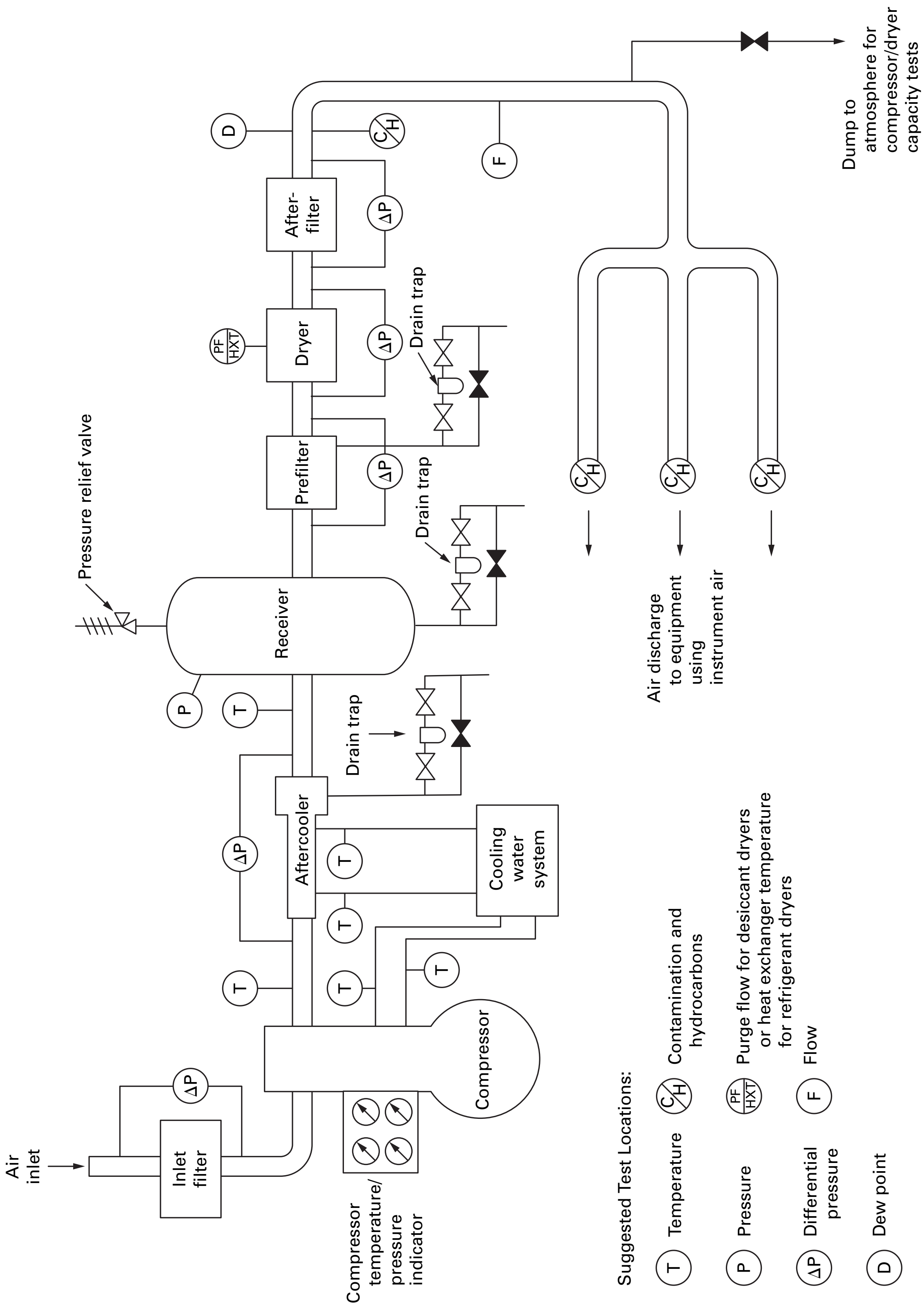
(d) take corrective actions to address conditions that do not fulfill acceptance criteria

(e) establish prerequisites for each test. Prerequisites should specify and conduct testing as close as practicable to design basis conditions for the subsystem being tested

(f) determine which performance tests specified in para. 5 are to be performed following maintenance or

[1] This is in agreement with definitions adopted by ASME PTC 9.

Fig. 1 Instrument Air System Typical Flow Diagram



modification of system components to ensure system performance has not been degraded

5.2 Baseline Performance Tests

Nonmandatory Appendix B provides a list of components that should be installed and used to perform the tests described in this Part. Test data should be monitored and documented to help verify that the system satisfies test acceptance criteria. Nonmandatory Appendix C provides guidance for determining the possible causes of deviations. Nonmandatory Appendix D provides sample data sheets.

(a) Baseline performance tests specified in this section should be performed after the prerequisites specified in Nonmandatory Appendix A have been completed. Baseline performance tests should

(1) Ensure that each instrument air system component meets or exceeds its performance specifications.

(2) Establish performance baseline data for comparison to inservice test results.

(b) The Owner should determine whether performance baseline data should be reestablished after a component is replaced, modified, or receives maintenance.

5.2.1 Compressor and Receiver Subsystem

(a) Compressor and receiver baseline tests should be conducted as close as practicable to design pressure and normal flow conditions to verify that design requirements are met.

(b) For multiple compressor and receiver systems, each compressor and receiver should be tested as close as practicable to their design conditions.

(c) Compressors should operate as close as practicable to their design conditions for a half hour, or longer if necessary to establish stable conditions, before performing baseline testing.

(d) Baseline testing should be performed to verify that system design requirements are met. Baseline data should be documented.

(e) The Owner should establish test procedures to obtain baseline data for

(1) compressor output flow, by means of a flow rate meter installed downstream of the receiver

(2) pressure drop across the compressor inlet filter

(3) inlet air temperature

(4) barometric pressure

(5) intercooler pressure and approach temperature for multistage units

(6) aftercooler ΔP and approach temperature

(7) compressor discharge air temperatures

(8) oil temperature

(9) oil pressure

(10) compressor outlet pressure

(11) input electrical power at compressor full load

(12) compressor and drive motor bearings vibration

(13) functionality of moisture separator and automatic drains

(f) Reduced flow tests should be performed when the compressor cycles at four-load/unload cycles per hour. The test shall

(1) verify operation of the unloaded system

(2) verify functionality of recycle and drain valves

(g) Oil samples should be taken during baseline tests. Tests should be established to determine

(1) water intrusion

(2) useful life of oil

(3) particulate contamination (quantity and type)

5.2.2 Dryer and Filter Subsystem

(a) The dryer and filter subsystem baseline test should be performed as close as practicable to dryer and filter design conditions.

(b) The test duration should be at least 8 hr.

(c) Test prerequisites should specify that dryer and filter inlet conditions be maintained as close as practicable to their design conditions including

(1) compressed air at design operating temperature

(2) test pressure at design pressure

(3) compressor outlet flow rate at design capacity of the dryer and filters

(d) Data to determine the following air dryer inlet and outlet parameters should be recorded at 1 hr intervals:

(1) dew point

(2) pressure

(3) flow rate

(4) temperature

(e) During the last 4 hr of the test, discharge air from the afterfilter should be checked at 1 hr intervals for particulate contamination and hydrocarbon contamination.

(f) During the seventh hour of the test, pressure drop should be measured across the filters (both pre- and afterfilters) and across the air dryer.

(g) When purge air is derived from compressed air, purge air usage should be determined either by direct flow measurement or by measurement and comparison of outlet flow and inlet flow of the air dryer.

(h) When a desiccant dryer is equipped with an energy management system (moisture load controls), a second test should be performed to determine the dew point at reduced flow. Dew point should be measured at 1 hr intervals. The test should

(1) provide two full cycles of the dryer

(2) be performed between 25% and 50% of design flow rate

(3) be performed at inlet temperatures that are as low as practicable

(4) verify the energy management function established in the acceptance criteria

5.2.3 Distribution Subsystem

(a) The Owner should establish a required minimum operational time for each special service air accumulator and its associated check valves upon loss of the main air system. The following sequence should be used for the pressure decay test for each special service air accumulator:

(1) With the accumulator at line operating pressure, isolate the compressed air system supply.

(2) Vent the piping upstream of the accumulator check valves to atmospheric conditions.

(3) Determine the elapsed time for the accumulator to decay to minimum acceptable pressure.

(b) A static pressure decay test of the Distribution Subsystem should be performed to verify its operational readiness.

(1) The Owner should establish acceptance criteria for minimum operational time with compressors tripped. The system pressures at unload and load setpoints should be established.

(2) Compressor load and unload setpoints should be verified with the compressor loaded and unloaded, with the system at design air usage.

(3) The test should be conducted with the compressor isolated and air supplied to the system only from the receivers.

(4) All portions of the Distribution Subsystem should be in service and aligned for normal operation before performing the test.

(c) Develop acceptance criteria within the design basis of the Distribution Subsystem equipment (ISA S7.0.01 is recommended) for the following parameters and verify conformance by obtaining air samples at the end of each major header in the system:

(1) dew point

(2) oil content

(3) particulate content

(4) minimum and maximum cycling pressures not part of ISA S7.0.01

5.3 Inservice Performance Tests

Periodic tests should be performed to ensure that the instrument air system meets acceptance criteria. Test data should be compared with baseline data to identify adverse trends or system and component degradation.

5.3.1 Compressor and Receiver; Dryer and Filter. The Inservice Performance Tests, data recordings, and checks of the compressor and receiver and dryer and filter are tabulated in Table 1.

(a) Triennial Tests. The Owner should conduct the following tests and visual examinations at least once every 3 years:

(1) Visually examine all internal surfaces accessible through inspection openings for corrosion, erosion, and abnormal corrosion products.

Table 1 Inservice Performance Tests: Compressor, Receiver, Dryer, and Filter

Item	Frequency [Note (1)]	Reference Paragraph
Visual inspections		
Internal surfaces for corrosion, erosion	T	5.3.1(a)(1)
External condition for corrosion, integrity of connections	T	5.3.1(a)(2)
Nondestructive examinations	T	5.3.1(a)(3)
Set relief valve pressures	T	5.3.1(a)(4)
Special service accumulators (check valve/decay tests)	RFO	5.3.1(b)(1)
Operability of distribution system components	RFO	5.3.1(b)(2)
Examinations		
Prefilter cartridge	SAC	5.3.1(c)(1)
Afterfilter	SAC	5.3.1(c)(2)
Tests		
Compressor/motor vibration	Q	5.3.1(d)(1)
Oil condition	Q	5.3.1(d)(2)
System pressure/cycling	Q	5.3.1(d)(3)
Header end point dew point	Q	5.3.1(d)(4)
Compressor inlet filter ΔP	M	5.3.1(e)(1)
Compressor load/unload time	W	5.3.1(f)(1)
Receiver/afterfilter ΔP	W	5.3.1(f)(2)
Desiccant dryer purge flow	W	5.3.1(f)(3)
Air dryer cycle time	D	5.3.1(g)(1)
Air dryer exit dew point	D	5.3.1(g)(2)
Checks		
Heat exchanger approach temperature	S	5.3.1(h)(1)
Compressor outlet temperature	S	5.3.1(h)(2)
Compressor oil pressure/level	S	5.3.1(h)(3)
Moisture separator/drain	S	5.3.1(h)(4)
Refrigeration dryer/drain	S	5.3.1(h)(5)

GENERAL NOTE: See para. 5.3.1 for details.

NOTE:

(1) Frequency symbols:
T = triennial
RFO = each refueling outage
SAC = semiannually and at changeout
Q = quarterly
M = montly
W = weekly
D = daily
S = shiftly

(2) Visually examine external areas of the air receiver for physical damage, leakage from pressure-retaining components, abnormal corrosion products, erosion, corrosion, and loss of integrity of bolted and welded connections.

(3) Nondestructive examinations may be performed as an alternative to the internal visual examination recommendations of para. 5.3.1(a)(1) to ensure that vessel wall thickness complies with the requirements of the Code of Construction and local jurisdictional requirements.

(4) Set pressures of compressors and receiver pressure-relief valves.

(b) Refueling Outage. The following tests should be performed at each refueling outage:

(1) Special service accumulators and associated check valves should be leak tested using the pressure decay test of para. 5.2.3(b).

(2) Distribution system components with specific operability requirements (e.g., check valves, service air cross-ties) should be tested for operability in accordance with Owner-established requirements, using the test procedures of para. 5.1(a).

(c) Semiannual Examinations. The following examinations should be performed semiannually and at cartridge change out:

(1) prefilter cartridge for contamination levels

(2) afterfilter for contamination levels

(d) Quarterly Tests. At least once every 3 months, the following tests should be conducted:

(1) compressor and drive motor bearing vibration

(2) condition monitoring of oil

(3) system pressure, minimum and maximum cycle time; measurements should be made at the end of each major header

(4) air samples for dew point and contamination measurements should be taken at the end of each major header

(e) Monthly Tests and Data Recordings. The following data should be recorded monthly:

(1) compressor inlet filter pressure drop

(f) Weekly Tests and Data Recordings. The following data should be recorded weekly:

(1) compressor load and unload time

(2) pressure drop between the receiver and the afterfilter outlet

(3) desiccant dryer purge flow

(g) Daily Tests and Data Recordings. The following data should be recorded daily:

(1) air dryer cycle time

(2) dew point

(h) Shift Checks. The following parameters should be checked and recorded every shift:

(1) heat exchanger approach temperature

(2) compressor outlet temperature

(3) compressor oil pressure and level

(4) moisture separator and automatic drain functionality

(5) refrigeration dryer separator automatic drain operation

5.3.2 Distribution Network. If compressor loading [para. 5.3.1(f)(1)] indicates an increase in system leakage, perform a pressure decay test similar to that described in para. 5.2.3(b); or, if system has flow measurement capability, record flow rates. The data should be analyzed and trended in accordance with para. 6.1.2 to determine if compressor degradation or excessive system leakage has developed since the last test.

6 ASSESSMENT AND CORRECTIVE ACTION

6.1 Assessment

6.1.1 Acceptance Criteria. The Owner should establish acceptance criteria for each component and test. Acceptance criteria should contain specific limits or acceptance ranges based on design basis conditions or vendor specifications.

6.1.2 Analysis and Trending. When data are obtained from a test recommended by this Part, they should be analyzed to determine if they reflect acceptable performance. All operating and test conditions should be considered when data are analyzed. The Owners should consider the history of the test data for the system and each component and do the following:

(a) Establish procedures and methods by which test data should be analyzed.

(b) Evaluate test data for compliance with acceptance criteria.

(c) Trend test data to predict when parameter acceptance criteria will be reached.

(d) Document unacceptable conditions and identify the cause(s).

(e) Establish corrective actions for unacceptable conditions.

6.1.3 Evaluation of Data. The Owner should have procedural guidelines to establish how and when test data are to be evaluated. This evaluation should establish why a set of data was found unacceptable and determine the cause of the problem. The evaluation should also include recommended corrective actions.

6.2 Corrective Action

Unacceptable performance should be corrected (see Nonmandatory Appendix C). Corrective actions should comply with the Owner's Quality Assurance Program. Either immediate corrective actions or corrective actions to prevent recurrence or both should be documented in accordance with the requirements of para. 8.2.

6.2.1 Immediate Corrective Action. If the results of a component test do not meet established acceptance criteria, then corrective action should be initiated within the time established by the Owner. Postmaintenance tests should be performed in accordance with the requirements of para. 5.2 before the component is returned to service and the system declared operationally ready.

6.2.2 Corrective Action to Prevent Recurrence. The cause of the unacceptable condition shall be determined and corrective actions taken to prevent recurrence.

7 INSTRUMENTATION

(a) Accuracy, range, and calibration of instruments should comply with established procedures and practices for instrumentation, including measuring and test equipment.

(b) Test instrument calibration frequency should comply with established procedures.

8 RECORDS AND RECORD KEEPING

8.1 Equipment Records

(a) Operation, maintenance, and modification records should be established and maintained for

(1) compressor

(2) dryer

(3) other components critical to the operation of the system such as

(a) filters

(b) heat exchangers

(c) moisture traps

(d) accumulators

(e) block and bypass valves

(f) interconnecting piping

(b) Operation and maintenance manuals should be available for

(1) compressor

(2) aftercooler

(3) dryer

(4) filters

(5) instrumentation used in performance testing

(c) Other records that should be available are

(1) initial startup test results and procedures

(2) original equipment specifications and subsequent revised specifications

(3) all baseline data, including original data as well as that resulting from revisions

(4) check for availability of documents for ASME Boiler and Pressure Vessel Code vessels (U-1A Form)

8.2 Record of Tests and Corrective Actions

Test records should be maintained and kept available for the life of the equipment. Test records should include test procedures, date of test, values of test measurements, instrumentation tolerances, date of test instrument calibration, analysis of test results, name of responsible test coordinator, names of persons performing the test, and corrective action taken.

8.2.1 Documentation of Corrective Actions. Documentation of tests and corrective actions taken should include the following:

(a) component identification (manufacturer, model number, and serial number)

(b) summary of test data and corrective actions taken to address conditions that did not fulfill acceptance criteria

(c) postmaintenance test data

(d) identification of root cause and technical justification for corrective actions taken

PART 17
NONMANDATORY APPENDIX A
Prerequisites for Baseline Testing

A-1 COMPRESSOR AND RECEIVER SUBSYSTEM

A-1.1 Before Energizing the System

Before energizing the system, perform the following activities:

(a) Visually inspect air receivers for external damage. If provided with a manhole, inspect internal receiver surfaces for contamination and corrosion.

(b) Ensure that necessary manuals and operating instructions for the equipment are available.

(c) Verify installation per design requirements (e.g., power input, piping configuration including inlet and outlet orientation, valve orientation, blanks removed, desiccant bags removed, shipping braces removed).

(d) Check instrument calibration and sensor set points.

(e) Perform a low-voltage control circuit check.

(f) If applicable, check pneumatic controls using dry air or nitrogen from an external source.

(g) Bench test relief valves to verify setting.

(h) Verify that all necessary compressor and aftercooler support systems are available.

(i) Verify that equipment has been serviced per design specification (e.g., compressor properly lubricated).

(j) Verify trap and drain valve functionality (receiver, aftercooler separator, and compressor).

(k) Verify that a leak test has been performed.

A-1.2 After Energizing the System

After energizing the compressor, perform the following activities:

(a) Check the motor for proper direction of rotation.

(b) Run the compressor in unloaded mode to check the system integrity (air and oil leaks).

(c) Operate the compressor in loaded mode to

(1) verify unload function

(2) verify operation of pressure and temperature trips

(d) Check compressor vibration for compliance with acceptance criteria.

A-2 DRYER AND FILTER SUBSYSTEM

A-2.1 General

(a) Ensure that necessary manuals and operating instructions for the equipment are available.

(b) Check installation per design drawings.

(1) power input voltage

(2) piping configuration

(3) power and control wiring

(c) Service dryers per specification.

(d) Check coalescing filter assemblies for proper installation of cartridge.

(e) Check availability of documents for ASME Boiler and Pressure Vessel Code vessels (U-1A Form) and applicable manufacturer's stamp for the dryer and filter pressure vessels.

(f) Bench test pressure-relief valves to verify settings.

(g) Check temperature and pressure indicators for physical damage.

A-2.2 Compressed Air Dryer — Desiccant

A-2.2.1 Before energizing dryer

(a) Check desiccant level and type.

(b) Check pressure-relief valves for damage (if supplied) and bench test to verify settings.

(c) Pressurize dryer and check for leakage.

A-2.2.2 After energizing dryer

(a) Run dryer through one complete cycle to verify control system and valve operation.

(b) Test all alarms and monitoring equipment for function per design specification.

A-2.3 Compressed Air Dryer — Refrigeration

A-2.3.1 Before energizing dryer

(a) Check drain valve on dryer separator.

(b) Pressurize dryer and check for leakage.

A-2.3.2 After energizing dryer

(a) Check for proper refrigerant and air heat exchanger temperature.

(b) Test all alarms and monitoring equipment for function per design specification.

A-3 DISTRIBUTION SUBSYSTEM

(a) Ensure that necessary manuals and operating instructions for vendor-supplied equipment are available.

(b) Blow down system piping.

(c) Perform a pressure boundary leakage test or initial service leak test.

PART 17
NONMANDATORY APPENDIX B
Recommended System Design Considerations

Several performance tests recommended in Part 17 may require hardware configurations not found in all nuclear power plants. This Appendix details specific design features that should be incorporated to complete the specified testing.

B-1 COMPRESSOR AND RECEIVER SUBSYSTEM

The following system features should be incorporated to facilitate testing:

(a) Pressure drop indication across the compressor inlet filter (or a pressure gauge downstream of filter).

(b) Flow indication downstream of receiver capable of measuring compressor design capacity [see para. B-2(e)].

(c) Provision for simulating air demand equal to compressor design capacity [e.g., valved piping to atmosphere downstream of flow measurement instrumentation; see para. B-2(d)].

NOTE: If compressor design capacity exceeds dryer design capacity, venting should also be upstream of the dryer.

(d) Provision for test gauges (temperature and pressure) on compressor discharge.

(e) Motor current indicator on compressor motors.

(f) Compressor motor run-hour and compressor loaded-hour meters.

(g) Aftercooler air outlet temperature and cooling water inlet temperature indication.

B-2 DRYER AND FILTER SUBSYSTEM

(a) Inline dew point indication with alarm or provision for connection of portable dew point instrument downstream of dryer afterfilter.

(b) Sample point between prefilter and dryer.

(c) Sample point downstream of afterfilter.

(d) Provision for simulating air demand equal to dryer rated flow.

(e) Flow indication downstream of dryer capable of measuring dryer design flow.

(f) Pressure drop indication across prefilters, dryers, and afterfilters.

B-3 DISTRIBUTION SUBSYSTEM

(a) Sample point at end of each major header.

(b) Test gauge (pressure) tap at end of each major header.

PART 17
NONMANDATORY APPENDIX C
Deviations and Corrective Actions

This Appendix provides guidance on determining the possible causes of deviations from acceptance criteria for some of the more critical parameters. See Tables C-1 through C-4 on the pages that follow.

Table C-1 Compressor and Receiver Subsystem

Symptom	Possible Cause(s)
Excessive pressure drop across compressor inlet filter	Dirty/clogged filter element
No pressure difference indicated across compressor inlet filter	Torn/damaged filter element
Inability to develop adequate discharge pressure, reduction of compressor capacity, or increased loading cycle frequency and/or compressor capacity output	System leakage, e.g., faulty automatic drain system Clogged air inlet filter Excessive internal worn clearances of compressor stage(s) Change in system demand (requirement exceeds compressor output); clogged receiver lowpoint drain and automatic trap malfunction resulting in reduced receiver volume due to water buildup Excessive pressure drop in the air distribution system
High compressor discharge air temperatures	Insufficient cooling to compressor cylinder jackets and coolers Fouled coolers; requires cleaning and/or replacement Compressor overpressure; results in higher than normal discharge temperatures Excessive internal worn clearance of compressor stage(s) causes unbalanced pressure ratios and redistribution of work resulting in high stage temperatures Faulty compressor valving allowing high pressure, high temperature air to leak back into preceding suction cavity
Inadequate oil pressure	Clogged and dirty oil filter Oil leaks Improper oil type for operating condition Worn and damaged oil pump; worn and damaged oil seal

Table C-2 Filters

Symptom	Possible Cause(s)
Prefilter fails to remove liquids or solids	Automatic drain fails to open Prefilter cartridges not installed or improperly installed, allowing bypass air flow Incorrect or defective filter cartridges Flow rate too high for prefilter rated capacity
Prefilter has high differential pressure	Prefilter cartridges are dirty Incorrect or defective prefilter cartridges Flow rate is too high for prefilter rated capacity Failure of automatic drain valve either to open or close
Prefilter has low differential pressure	Filter cartridge missing, damaged, or improperly installed
Afterfilter failed to remove contamination	Afterfilter cartridges missing or improperly installed allowing bypass air flow Incorrect or defective filter cartridges Flow rate too high for afterfilter rated capacity
Afterfilter has high pressure drop	Afterfilters for desiccant dryers are intended primarily for desiccant dust removal, so high quantities of desiccant dust may be an indication of improper dryer operation or excessive flow rates through air dryer Afterfilter cartridges are dirty Incorrect or defective afterfilter cartridges Flow rate is too high for afterfilter rated capacity
Afterfilter has low pressure drop	Filter cartridge not installed, damaged, or improperly installed

Table C-3 Air Dryers

Symptom	Possible Cause(s)
High dew point, desiccant dryer	Failure to regenerate: No purge air No heat (heated dryer) Cycle failure Valve failure Desiccant fouled Operational problems: Dryer bypass block valves open Air flow rate greater than design capacity
High dew point, refrigeration dryer	Refrigeration failure: Compressor failure Refrigerant leaks Condensing unit heat exchanger fouled Refrigeration controls failure Water removal failure: Automatic drain failure Separator failure Air flow rate greater than design capacity
High pressure drop, desiccant dryer	Desiccant has become attrited into fine particles causing high flow resistance Desiccant fouled Desiccant support screens clogged Air flow rate greater than design capacity
High pressure drop, refrigerant dryer	Water separator clogged Compressed air heat exchanger clogged Automatic drain failed open or closed

Table C-4 Distribution Subsystem

Symptom	Possible Cause(s)
Pressure decay test indicates shortened decay time	Increased system leakage Increased system demand Lower initial pressure
Low pressure at end of header	Compressor has degraded (see Table C-1) Air consumption is too great for header size Increased system leakage
High dew point at end of header	Poor dryer operation (see Table C-3) Header ran through area with excessive low temperature and has a low air flow
High particulate content at end of header	Internal corrosion of end of header piping or equipment Afterfilter not working (see Table C-2)
High oil content at end of header	Prefilter malfunctioning (see Table C-2) Component supplied by air system malfunctioning, feeding back into air system

PART 17
NONMANDATORY APPENDIX D
Sample Data Sheets

See Tables D-1 and D-2 for sample data sheets.

Table D-1
Compressor and Receiver Subsystem Performance Sample Data Sheet

Parameter	Symbol	Units	Acceptance Criteria	Measured Value
Inlet filter ΔP	$IF\ \Delta P$	psid [kPa (differential)]	Note (1)	
Compressor oil level	*OL*	. . .	Note (1)	
Compressor oil pressure	*Po*	psig [kPa (gage)]	Note (1)	
Load setpoint	*Pl*	psig [kPa (gage)]	Note (1)	
Unload setpoint	*Pu*	psig [kPa (gage)]	Note (1)	
Power loaded	*Lkw*	kW	Note (1)	
Power unloaded	*Ukw*	kW	Note (1)	
Vibration	*V*	mils (μ)	Note (1)	
Aftercooler outlet temperature	*To*	°F (°C)	Note (1)	
Compressor outlet temperature	*Co*	°F (°C)	Note (1)	

NOTE:
(1) Established by Owner (values to be filled in prior to testing/measuring).

Table D-2 Distribution Subsystem Performance Sample Data Sheet

Parameter	Symbol	Units	Acceptance Criteria	Measured Value
Unload pressure	*Pu*	psig [kPa (gage)]	Note (1)	
Initial receiver pressure	*Pl*	psig [kPa (gage)]	Note (1)	
Initial time	*Ti*	min		
Final time	*Tf*	min	Note (1)	
Maximum loss of air	*DT*	min	Note (1)	
Time ($DT = Ti - Tf$)			Note (1)	
Dew point (at line pressure)	*DP*	°F (°C)	Note (1)	
Particulate	*PC*	microns	Note (1)	
Normal pressure	*P*	psig [kPa (gage)]	Note (1)	
Oil content	*OC*	ppm	Note (1)	

NOTE:
(1) Established by Owner (values to be filled in prior to testing/measuring).

PART 19

PART 19
Preservice and Periodic Performance Testing of Pneumatically and Hydraulically Operated Valve Assemblies in Light-Water Reactor Power Plants

1 INTRODUCTION

1.1 Scope

This Part provides guidance for preservice and inservice testing to assess the operational readiness of certain pneumatically and hydraulically operated valve assemblies used in light-water reactor (LWR) power plants.

The pneumatically and hydraulically operated valve assemblies covered are those 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.

This Part recommends test methods, test intervals, parameters to be measured and evaluated, acceptance criteria, corrective actions, and records requirements.

1.2 Exclusions

Valve assemblies that perform no active function within the scope defined in para. 1.1 are excluded from testing under this Part. The guidance applies to active valve assemblies; however, the guidance may be used for passive valve assemblies if the Owner elects to ensure that the valve assemblies are set properly to maintain their passive position. Self-operated pneumatic and hydraulic devices, such as air supply regulators, are excluded from the scope of this Part, except where they are included as a subpart of the valve assembly.

2 DEFINITIONS

The following list of definitions is provided to ensure a uniform understanding of selected terms used in this Part:

baseline test: a test to collect data at specific repeatable conditions to establish a basis for comparison with subsequent inservice test data.

bench set: for operators with a spring, the pressure range over which the operator will stroke from start to its rated travel. Bench set is typically adjusted without service loads and typically either without friction loads or with minimal friction loads.

dynamic test: a test conducted with system pressure and/or flow.

expected service conditions: plant conditions at which the valve assembly is required to operate to perform its intended safety function.

hydraulic operator: a device that provides energy to open, close, or position a valve via hydraulic pressure.

inservice test: a test to determine the operational readiness of a system, structure, or component after first electrical generation by nuclear heat.

maximum available pneumatic pressure: the maximum pressure available to the actuator.

operational readiness: the ability of a component to perform its intended function(s).

performance testing: a test, or combination of tests, designed to acquire operational performance data, including baseline tests, inservice tests, or periodic stroking of the valve assembly.

pneumatic operator: a device that provides energy to open, close, or position a valve via pneumatic pressure.

preservice test: a test performed during the preservice test period to verify the capability of the valve assembly to perform its intended safety function.

preservice test period: the interval from completion of construction activities related to the valve assembly to the first electrical generation by nuclear heat in which component and system testing take place; or, in an operating plant, the interval to the valve assembly initially being placed in service.

seat load: the total net contact force between the valve closure member and the valve seat.

spring rate: the force change per unit change in length, usually expressed as pounds per inch or Newtons per millimeter.

static test: test at ambient conditions without system pressure or flow.

stroke time: the time interval from initiation of the actuating signal to the indication of the end of the operating stroke.

total friction: the sum of packing friction, valve internal friction, and operator friction.

valve assembly, hydraulically operated: a valve and its associated hydraulic operator, including all components required for the valve to perform its intended safety function.

valve assembly, pneumatically operated: a valve and its associated pneumatic operator, including all components required for the valve to perform its intended safety function.

3 TEST GUIDANCE

The purpose of preservice testing is to verify the capability of the valve assembly to perform its intended safety function prior to initially placing the valve assembly in service. The purpose of performance testing is to monitor the valve assembly for degradation. Baseline testing is to establish baseline data for comparison to subsequent inservice test data. Inservice testing generates data to compare to baseline data and to assess the operational readiness of the valve assembly. Periodic stroking of the valve assembly ensures that the valve is not binding and that the valve operator is functional. Records of data should be prepared and maintained.

3.1 Preservice Test Guidance

Valve assemblies requiring preservice testing should be subject to the testing guidance of para. 4.3.1 prior to being initially placed in service to verify that valve assembly performance is in conformance with plant licensing requirements and capable of performing its intended safety function(s). Preservice testing should be accomplished prior to the end of the preservice test period.

3.2 Performance Test Guidance

Periodic performance testing should be performed in accordance with certain guidance.

3.2.1 Baseline Test Guidance. Valve assemblies should have a baseline test to establish reference values for comparison to subsequent inservice test data. The baseline test is performed when the valve assembly is initially placed in service and following activities that may affect the operating parameters of the valve assembly in accordance with para. 3.3. Testing should be in accordance with para. 4, with test conditions in accordance with the guidance of para. 4.3.2.

3.2.2 Inservice Test Guidance. Valve assemblies should be tested in accordance with para. 4 at a frequency established by the Owner.

3.2.3 Periodic Valve Assembly Stroke Test. Once during each plant cycle of operation, but not to exceed once per 24 months except to coincide with a refueling outage, valve assemblies should be operated to move the valves through one full stroke (open and close). If a valve assembly experiences a full stroke during the plant cycle of operation, the Owner may document such operation and no additional testing is required. No specific plant conditions apply to this test. The valve assembly stroke test is to ensure that the valve is not binding and that the valve operator is functional. No measurement of stroke time is required.

3.3 Equipment Replacement, Modification, Repair, and Maintenance Test Guidance

(a) When a valve assembly has been replaced, repaired, or has undergone maintenance that could affect the valve assembly's performance, new reference values should be determined or the previous value reconfirmed by an inservice test before it is returned to service or immediately if not removed from service. This is to demonstrate that performance parameters that could be affected by the replacement, repair, or maintenance are within acceptable limits. Deviations between the previous and new reference values should be identified and analyzed. Verification that the new values represent acceptable operation should be documented in the record of tests (see para. 4.7).

(b) A valve assembly affected by a design change that alters system operating parameters should be inservice tested to reconfirm or establish new reference values for those baseline parameters that could have been affected.

(c) A valve assembly modification that changes operating parameters should be inservice tested to reconfirm or establish new reference values for those baseline parameters that could have been affected.

4 TEST METHODS

Test methods should be applied to valve assemblies determined to be subject to the guide. Where the testing is performed other than in situ, the Owner is responsible for establishing conformance with the test methods.

4.1 Prerequisites

The Owner should identify valve assemblies to be tested in accordance with this paragraph. All performance testing should be in accordance with plant-specific installation, acceptance, maintenance, surveillance, or other applicable procedures.

4.2 Instrument Calibration

Instruments used for valve assembly tests should be checked to ensure their calibration is current in accordance with the Owner's Quality Assurance Program.

4.3 Test Conditions

4.3.1 Preservice Test Conditions. All preservice tests should be performed without any changes, modifications, or adjustments to the valve assembly during testing. A static test in combination with at least one of the following should be performed for preservice tests of valve assemblies:

(a) dynamic test at expected service conditions
(b) correlation with a similar valve assembly that has been dynamically tested at similar or bounding conditions
(c) extrapolation of results of dynamic tests at highest practicable conditions
(d) calculational methods, if it can be shown that the methods provide a conservative result

4.3.2 Periodic Performance Test Conditions. Tests should be performed without any changes, modifications, or adjustments to the valve assembly during testing. The Owner should determine the test conditions that apply to valve assemblies based on the selection of the test parameters in accordance with para. 4.6. The baseline test should be performed at specific repeatable conditions. The inservice tests should be performed at the conditions used to establish baseline values. Periodic valve assembly stroke testing may be performed at any plant condition that will not cause damage to the valve assembly.

4.4 Limits and Precautions

The plant should not be placed in an unanalyzed configuration that may cause a transient, or that places undue stress on a system or component, to obtain data during preservice or performance testing.

4.5 Test Procedures

Procedures should be established, as appropriate, to provide for
(a) methodical, repeatable, and consistent performance testing
(b) valid test data that are not influenced by any preconditioning associated with performance testing procedural steps
(c) data that reflects, or can be correlated with, the expected service conditions
(d) adequate data for analysis and evaluation per para. 5

4.6 Test Parameters

4.6.1 Test parameters monitored will vary with the intended safety function(s) of the valve assembly. The safety function(s) normally fall(s) into one or more of the following:
(a) open within a specified minimum or maximum time period, or both
(b) closed within a specified minimum or maximum time period, or both
(c) stroke open to obtain minimum flow or pressure
(d) stroke open or closed against flow/pressure, including maximum differential pressure for the valve assembly to fulfill its safety function, across the valve
(e) travel to a predetermined intermediate position
(f) remain in operating position for specified period of time
(g) operate a specified number of cycles

4.6.2 The valve assembly is characterized by physical properties and design parameters including effective area, spring adjustment, spring rate, pneumatic or hydraulic pressure and volume, valve stroke (travel), friction forces, and proper setup of valve assembly components. The Owner should determine which of the following parameters, or combination of parameters, which may be determined from data obtained during testing, are important to monitor depending on the safety function(s) of the valve assembly:
(a) bench set
(b) maximum available pneumatic pressure
(c) seat load
(d) spring rate
(e) stroke time
(f) actual travel
(g) total friction
(h) minimum pneumatic pressure required to accomplish the safety function(s) of the valve assembly
(i) hydraulic pressure at appropriate point in operation
(j) pneumatic and hydraulic fluid condition and cleanliness
(k) set point of pressure switch, relief valve, regulator, and so on
(l) others as applicable

4.7 Test Information

The following information should be recorded and/or verified:
(a) test conditions per para. 4.3
(b) name of test performer
(c) date of test
(d) valve assembly identification
(e) nameplate data
(f) test equipment identification and date of calibration
(g) remarks concerning abnormal or erratic action, either during or preceding performance testing
(h) other important observations during testing

5 ANALYSIS AND EVALUATION OF DATA

The following analysis and evaluation of data guidance should be applied to valve assemblies determined to be subject to the guide. Where the testing is performed other than in situ, the Owner is responsible for establishing conformance with the guidance.

5.1 Acceptance Criteria

The Owner should establish acceptance criteria by which test data should be analyzed. The criteria should specify the acceptable limits or range of test parameters based on design criteria necessary for the valve assembly to perform its intended safety function(s). The baseline test establishes data for comparison to inservice test data and should be used to establish the acceptable limits or range for subsequent testing. Design criteria may include applicable vendor information, facility technical specifications and safety analysis reports, Owner-established requirements, and other related documents. The Owner may specify a corrective action value below the acceptable limit so that actions may be taken to correct degradation before the acceptable limit is reached.

5.2 Analysis of Data

Test data obtained from a test performed under this Part should be analyzed to determine acceptable valve assembly performance. Both operating and test conditions should be considered.

(a) The Owner should compare performance test data to the parameter limits or range established in accordance with para. 5.1. If data being compared fall within the acceptable range of established parameters, the values are acceptable.

(b) The Owner should consider test history on a particular valve assembly and should establish performance test data trends to predict when data points may approach the acceptable parameter limits. Corrective action should be taken prior to the valve assembly exceeding its acceptable parameter limits. If the test data is unacceptable, corrective actions should be taken in accordance with para. 6.

5.3 Evaluation of Data

The Owner should establish guidelines for data evaluation that ensure the following:

(a) timely evaluation

(b) the valve assembly meets its established acceptance criteria and is capable of performing its intended safety function(s)

(c) corrective action is taken as described in para. 6 if a valve assembly is not capable of performing its intended safety function(s)

5.4 Documentation of Analysis and Evaluation of Data

The Owner should document the results of test data evaluation and analysis, which should include, as a minimum, the following:

(a) assumptions made

(b) values of test parameters and test information established in accordance with paras. 4.6 and 4.7

(c) statement of confirmation of operational readiness as verified in accordance with Owner's Quality Assurance Program

(d) summary of analysis and evaluation of data in accordance with paras. 5.2 and 5.3

6 CORRECTIVE ACTION

If the results of a valve assembly test do not appear to meet the acceptance criteria established in para. 5, the data should be analyzed within 24 hr. If the monitored parameters are outside acceptable limits, then corrective action should be initiated and the valve assembly should be declared inoperable. Valve assemblies declared inoperable may be repaired, replaced, or the data may be analyzed to determine the cause of the deviation and to show the valve assembly to be operating acceptably. If the Owner has also established a corrective action value that is below the acceptable limits, actions to correct degradation may be taken prior to declaring the valve assembly inoperable.

Plant-specific limiting conditions for operations should be followed if they are more limiting than this Part. The corrective action should bring the valve assembly back into compliance with acceptance criteria. When the corrective action consists of evaluating the acceptability of the valve assembly at the degraded conditions, new baseline data and acceptance criteria should be established. The valve assembly should be retested in accordance with para. 4 following the corrective action and prior to return to service. The cause of the failure should be evaluated for identification of corrective actions to prevent recurrence in similar valve assemblies. Documentation of corrective actions should include the following:

(a) valve assembly identification

(b) summary of corrective action and results

(c) subsequent test data or analysis, including analysis for valve assembly operability

(d) identification of cause of anomaly and technical justification for corrective action taken

(e) description of actions taken to restore operational readiness of the valve assembly

PART 23

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PART 23
Inservice Monitoring of Reactor Internals Vibration in PWR Power Plants

1 INTRODUCTION

1.1 Scope

This Part provides guidance for inservice vibration monitoring of reactor internals in Pressurized Water Reactor (PWR) power plants and recommends monitoring methods, intervals, parameters to be measured and evaluated, and record requirements.

1.2 Background

Figure 1 shows a cross-sectional view of a representative pressurized water reactor vessel and core support barrel. Flow-induced vibration of the core support barrel, fuel, and other internal structures act to change the thickness of the downcomer annulus (water gap) and affect the relative geometry of the fuel and surrounding structures. These variations cause small changes in the neutron flux sensed by ex-core power range neutron detectors located around the periphery of the reactor vessel (see Fig. 1).

The ex-core neutron flux signal is composed of a direct current component resulting from neutron flux produced by power operation of the reactor and a fluctuating signal or noise component. The fluctuating signal is composed of noise sources including reactivity response to temperature and pressure fluctuations; variations in neutron attenuation due to lateral and radial motion of the core support barrel and thermal shields; lateral motion of the fuel assemblies; and other potential vibration modes. These motions are usually very small sources of neutron noise but can be reliably identified in frequency spectra generated by Fourier analysis of the neutron noise signals to give spectral amplitude, phase, and coherence between signals from ex-core neutron detectors.

The natural frequencies and vibration of the reactor internals depend on their structural design and support conditions and on the vibration excitation mechanisms acting on them. Monitoring the neutron noise signals measured by the ex-core power range detectors has been shown to provide a means for detecting changes in the dominant internals structural conditions or vibration excitations.

The vibration characteristics of the reactor internals, for both as-built conditions and assumed degraded conditions, are determined by structural analysis and testing. The natural frequencies and mode shapes provide a basis for interpreting the significance of changes in the ex-core detector signals with respect to the internal structures and their support conditions. In addition to the ex-core neutron noise detector, other sensors can also provide supporting and supplemental data for detecting changes in the character of the internal structures and their support conditions. Accelerometers mounted on the reactor vessel [Fig. 1, sketch (a)] provide signals associated with loose parts impacting the reactor vessel and, in some cases, sounds associated with intermittent contact between internals components. In-core detectors [Fig. 1, sketch (b)] produce noise signals that can be used to monitor fuel assembly vibration and the motion of the in-core detector itself. An in-service monitoring program with well-coordinated loose-part monitoring accelerometers, in-core and ex-core neutron noise detectors, combined with comprehensive analysis and interpretation of the data, will enable an experienced engineer to detect changes in the condition of the reactor internals.

This Part should be implemented in a comprehensive program together with ASME OM-S/G–1997, Part 5, to routinely monitor the internals at power operation. The program should be defined in approved procedures, which identify the owners and users of the information obtained through the conduct of the program.

ASME OM-S/G–1990, Part 5, provides separate guidelines specifically for in-service monitoring for loss of core support barrel flange clamping force. Suitable review of the data acquired in this Part would, however, provide the information needed to detect anomalous core support barrel beam mode vibration.

2 DEFINITIONS

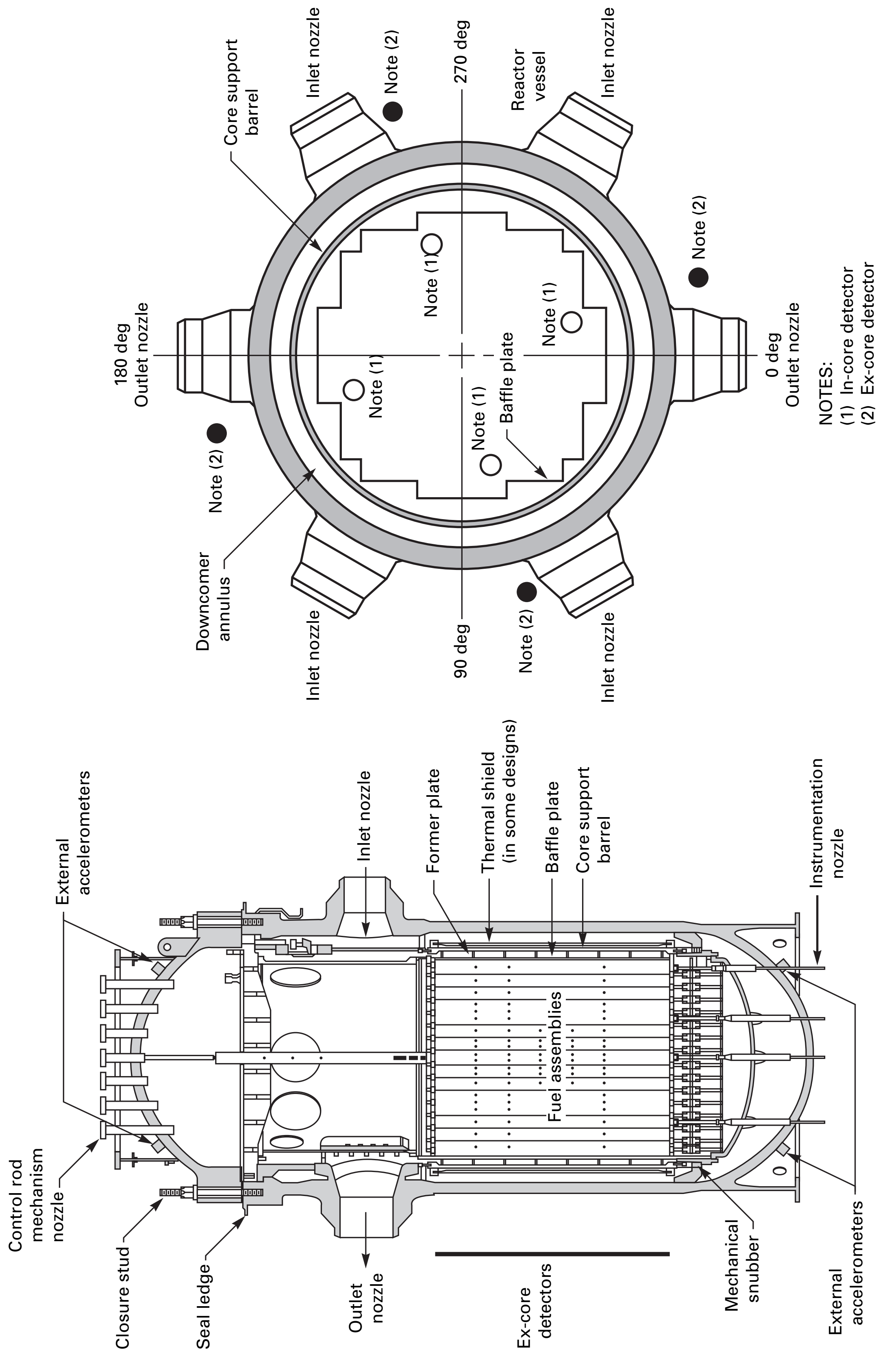
The following list of definitions is provided to ensure a uniform understanding of selected terms used in this Part:

amplitude probability density: a function of random data that describes the probability that the signal amplitude will assume a certain value within some defined range at any instant of time.

baffle jetting: localized flow from the region between the core support barrel and the core shroud into the region containing fuel assemblies.

bottom-mounted instrument thimbles: long, flexible pressure boundary tubes that pass through penetrations in

Fig. 1 Schematic of a Pressurized Water Reactor (PWR) Showing Typical Sensor Arrangement



(a) Reactor Arrangement

(b) Ex-Core Detector Locations

the lower reactor vessel head and into fuel assemblies to permit positioning miniature neutron detectors inside the core during reactor operation.

cantilever modes of vibration: vibration modes of a simple beam with one end clamped and one end free.

core baffle (or core shroud): the structure between the peripheral fuel assemblies and the core support barrel.

core support barrel: cylindrical structure located inside and concentric with the reactor pressure vessel that has the primary structural function of supporting the reactor core.

ex-core neutron detectors: neutron detectors, located outside of the pressure vessel and at the same elevation as the core, that are used to monitor neutron flux as an indication of reactor power.

fuel assemblies: a group of fuel rods, usually in a square array, spaced and supported by structural components.

in-core neutron detectors: miniature neutron detectors that can be positioned inside fuel assemblies to obtain local neutron flux measurements during reactor operation.

mechanical snubbers: in a reactor, dynamic restraint devices in which load can be transmitted between tabs on the core support barrel and adjacent tabs on the inside of the reactor vessel.

natural frequency: the frequencies at which a system will vibrate in the absence of any external forces.

neutron noise: fluctuations in the neutron signal from a reactor operating at steady state. These fluctuations are considered noise for the measurement of reactor power, but contain information that can be correlated to structural motion and thermal hydraulic effects.

pump-induced vibrations: structural vibrations driven by mechanical coupling of reactor coolant pumps to the reactor vessel and by pump outlet pressure pulsation transmitted through the reactor coolant.

shell modes of vibration: vibration modes of cylindrical shell structures involving displacements primarily in the radial directions.

thermal shield: a steel cylinder mounted on the outside of the core support barrel to attenuate radiation and the associated radiation heating of the pressure vessel.

The following terms pertaining to random data analysis are defined in ANSI S2.10 (1971): *autopower spectral density function (APSD), cross-power spectral density function (CPSD), cross-spectral density, coherence function (COH), power spectral density (PSD),* and *root mean square (rms)*.

3 REFERENCES

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Lubin, B. T., Longo, R., and Hammel, T., 1988, "Analysis of Internals Vibration Monitoring Systems Data Related to the St. Lucie I Thermal Shield Failure," Progress in Nuclear Energy, Vol. 21, pp. 117–126

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Sweeney, F. J., March-Leuba, J., and Smith, C. M., 1983, "Contribution of Fuel Vibrations to Ex-Core Neutron Noise During the First and Second Fuel Cycles of the Sequoyah 1 Pressurized Water Reactor," Progress in Nuclear Energy, Vol. 13, pp. 283–290

ANSI S2.10-1971, "Methods for Analysis and Presentation of Shock and Vibration Data"

Publisher: American National Standards Institute (ANSI), 25 West 43rd Street, New York, NY 10036

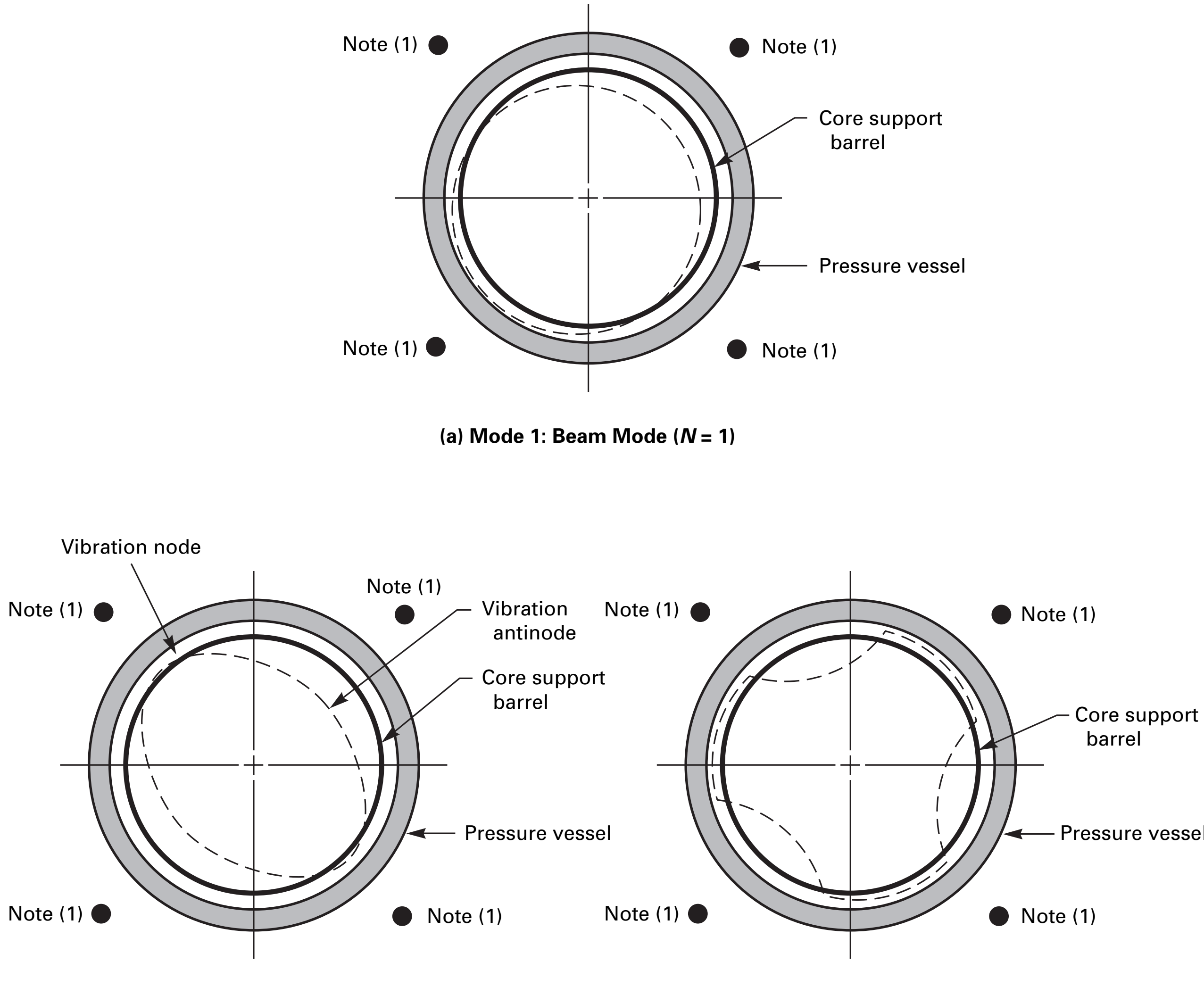
ASME Boiler and Pressure Vessel Code (BPVC) 1998, Section III, Appendix N Series

ASME OM-S/G–1997, Standards and Guides for Operation and Maintenance of Nuclear Power Plants, Part 5, "Inservice Monitoring of Core Support Barrel Axial Preload in Pressurized Water Reactor Power Plants"

ASME OM-S/G–1993, Standards and Guides for Operation and Maintenance of Nuclear Power Plants, Part 12, "Loose Part Monitoring in Light Water Reactor Power Plants"

Publisher: The American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016-5990; Order Department: 22 Law Drive, P.O. Box 2300, Fairfield, NJ 07007-2300

Fig. 2 Beam and Shell Mode Vibration of a PWR Core Support Barrel



(b) Mode 2: First Shell Mode (N = 2) **(c) Mode 3: Second Shell Mode (N = 3)**

GENERAL NOTE: N is the number of full sinewaves around the circumference of the structure.

NOTE:
(1) *Ex-core neutron detector.*

4 INTERNALS VIBRATION EXCITATION SOURCES, RESPONSES, AND MODES

4.1 Sources of Excitation and Responses

Under normal operating conditions, reactor internals vibrations could be induced by the following excitation sources: flow turbulence; pressure pulsation and mechanical motions produced by the reactor coolant pumps; vortex shedding; and fluidelastic forces. The characteristics of these excitations are described in the following paragraphs.

4.1.1 Flow Turbulence. Flow turbulence is mainly generated by changes in the boundaries of the flow paths, causing random fluctuating forces to act on the flow channel surfaces. The magnitude of these forces decreases with increasing frequency. The dominant responses are narrow-band peaks around the structural natural frequencies.

4.1.2 Pump-Induced Excitations. These excitations are at the pump rotating speed and impeller blade passing frequency (pump rotating speed times number of impeller vanes) harmonics. The wave form is composed of a series of sinusoidal, harmonically related tones. The overall wave form contains sinusoidal vibrations from all running reactor coolant pumps. Because of this, time variation of the overall wave form due to constructive and destructive interference is likely due to both phase and pump speed variations. An example of this space-time variation of coolant pump-induced excitation is given in Nonmandatory Appendix C, Fig. C-3.

4.1.3 Vortex Shedding. Vortex shedding due to flow perpendicular to the axis of cylinders produces sinusoidal or narrow band random forces. The resulting forces are generally significant only when the vortex shedding frequency is close to a structural natural frequency.

4.1.4 Fluidelastic Excitations. These forces are generated by flow perpendicular or parallel to the axis of a cylinder or an array of cylinders. The forces do not exist when the structure has no motion. The wave form is nearly sinusoidal at the natural frequencies of the coupled fluid-structural system.

Additional information and methods for calculating vibrations induced by these forces are given in Au-Yang (1986), Mulcahy (1983), and ASME BPVC 1998, Section III, N-1300 and 1400.

4.2 Vibration Modes

4.2.1 Types of Modes. Internals vibrate in axial, lateral, and torsional modes. Axial modes are formed by axial extensions and compressions of the structures, bending of plates, and end flange flexibilities. Lateral modes can be breathing, shell, or beam modes (Fig. 2). Torsional modes are produced by twisting of the structures, as commonly associated with shafts. In para. 4.2.2, the modes are denoted by the structure or component that dominates the vibration of the mode. It should be recognized, however, that several structures or components usually participate to some extent in these modes.

4.2.2 Dominant Internals Modes and Their Characteristics in Ex-core Detector Noise Signals. Although several components participate in structural modes, specific modes are commonly associated with the structure that has the dominant response. The dominant modes generally detectable in the ex-core detector are described.

(a) *Core Support Barrel Beam Modes.* These are generally cantilever modes in which there is some participation of the reactor vessel, fuel assemblies, and the circular thermal shield. In some cases, contact at the snubbers at the lower end of the core support barrel may result in a higher frequency mode. Preloads at the snubber may result in a clamped-pinned mode. In other cases, intermittent contact at the snubbers might result in nonlinear modes.

(b) *Fuel Assembly Beam Modes.* These modes occur at fuel assembly natural frequencies and are detectable in ex-core detector signals. The core support barrel has some participation in these modes.

(c) *Core Support Barrel Shell Modes.* There are generally more than one of each ($N = 2$, $N = 3$, etc.; see Fig. 2) of these modes. However, a detector might not be able to pick up one or more of these modes if it is located near a node (zero vibration amplitude) point of the mode(s).

Table 1 Sensor Types and Potential Applications in Reactor Noise Analysis

Detector	Typical Useful Frequency Range, Hz	Potential Applications
Excore power range ionization chambers	< 100	Core internals vibration monitoring
Incore neutron detector		
Fission chamber	< 100	Coolant velocity measurements (PWR)
Fast SPND	< 100	Fuel assembly vibration (PWR)
Rhodium SPND	< 10	TIP tube vibration (BWR)
Vibration monitoring		
Accelerometers	10–10,000	Structural vibrations
Displacement	10–10,000	Pump monitoring
Temperature		
RTD (no thermal well)	< 1.0	Flow monitoring

(d) *Thermal Shield Shell Modes.* These modes occur in the same manner as the core support barrel shell modes. The dominant motion is the thermal shield and there is some participation of the core support barrel for designs that have circular thermal shields.

5 SIGNAL DATABASE

5.1 Signals to Be Monitored and Reactor Conditions

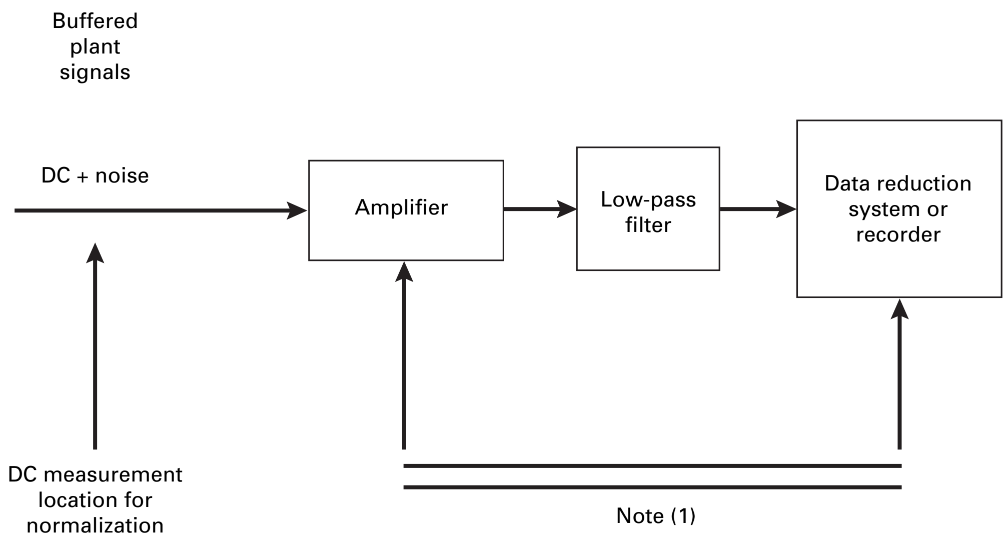
Table 1 lists detector types with potential applications drawn from past vibration and noise monitoring experience. The program defined in this part requires only that ex-core detector signals be monitored. The other detectors may be used to broaden the data base. Data acquisition for each type of detector is discussed in the following paragraphs. The functions to be generated during data reduction are discussed in para. 5.5.

During data acquisition, the reactor should be at a steady power level, there should be no control rod movement or boron dilution or injection.

5.2 Data Acquisition

The equipment necessary for acquisition of the required signals includes devices to buffer signals to isolate the data acquisition activities so that other plant systems are unaffected; devices to block or remove the DC signal; amplifiers to increase signal levels to provide the maximum available signal-to-noise ratio; filters (low-pass, high-pass, band-pass, band-reject) to reduce the effects of signals not related to core internals vibration, to limit the frequency bandwidth of the signal, and to prevent aliasing in digital systems; and devices to analyze the data, record the data for later analysis, and

Fig. 3 Typical Components in a Signal Data Acquisition System



NOTE:
(1) Gain of entire system must be known for proper normalization.

provide storage of signals or analysis results. Figure 3 shows the typical arrangement of equipment in a data acquisition system.

The implementation of a data acquisition program should include the equipment listed above, testing and calibration of the equipment, and data validation and documentation. Signal buffering is necessary to isolate the noise data acquisition system from other plant systems and to prevent the contamination of the noise data by other devices sharing the signal. Test and calibration of the data acquisition system by introducing a signal of known characteristics verifies that the equipment tested is functioning properly and determines the gain, frequency response, and noise characteristics of the calibrated equipment. Signals should be recorded on analog or digital magnetic tape, magnetic disk, optical disk, or other analog or digital mass data storage devices. Signals may also be analyzed online and the results as well as the original data recorded.

5.3 Signal Sampling

Data reduction for recording and noise analysis involves conditioning the signal for analysis, sampling analog noise signals, time or frequency domain analysis, display of results, and validation of results.

Analog noise signals should be amplified to sufficient levels to be accurately represented in digital format. However, the signals must not overload the analog to digital converter or conditioning amplifier. Noise signals also should be filtered to prevent aliasing. Sampling analog signals at a given time interval, ΔT, yields data of a selected time resolution for correlation analysis or of a selected frequency bandwidth for spectral analysis.

Table 2 Relationships Between Sampling Rates and Analysis Results

Quantity	Relationship
Sampling interval	ΔT
Sampling rate	$f_s = 1/\Delta T$
Maximum (Nyquist) frequency (Hz) [Note (1)]	$1/(2\Delta T)$
FFT sample block size (number of data points per block)	n (must be 2^k where k is an integer)
FFT spectrum lines [Note (1)]	$n/2 + 1$ (including $f = 0$)
FFT frequency resolution (Hz)	$\Delta f = 1/(n\Delta T)$
Number of correlation lags (inverse FFT of block spectra)	$(n/2)-1$
Correlation length(s)	$(n-1)\Delta T$ blocks
Number of data blocks	N (100 blocks is recommended)
Total length of time record needed	$T = Nn\Delta T$
Normalized error in PSD Estimate	$\epsilon = 1/\sqrt{N}$

NOTE:
(1) This is the theoretical maximum. In practice, the useful maximum frequency is less than the theoretical maximum and usually varies between $1/(2.2\Delta T)$ and $1/(3.0\Delta T)$ depending on the slope and set point of the anti-aliasing filter.

Spectral analysis with digital computers uses the Fast Fourier Transform (FFT) algorithm in which the sampling rate $1/\Delta T$, the sample block size n, the frequency resolution Δf, the statistical accuracy as measured by the normalized error, and the total length of time record T are all interrelated as shown in Table 2. Nonmandatory Appendix D gives an example on selection of these parameters for signal sampling.

5.4 Signal Recording

Data may be digitally recorded or recorded on an analog recorder. Information to be documented is included in para. 5.7. Nonmandatory Appendix D provides additional information on sampling rates for digital recording and length of data record.

5.5 Data Reduction

5.5.1 Frequency Spectral Functions. Frequency spectral functions useful in the analysis of the detector signals are included in Part 5 and ANSI S2.10.

Further clarification of signal content can be obtained by separating the frequency spectral content of signal pairs into in-phase and out-of-phase contents of these two signals. This technique is described in Nonmandatory Appendix A.

Specific spectral functions for ex-core detectors are provided in para. 5.5.2.

5.5.2 Ex-Core Detectors. Beam and shell modes of the core support barrel and thermal shield due to flow turbulence and pump-induced vibrations can be detected by the ex-core neutron detectors. The vibration of fuel assemblies near the detectors is also reflected in the signals of these detectors.

Data should be acquired to permit generation of at least 0 to 50 Hz frequency spectra with a frequency resolution of 0.15 Hz or less; 100 blocks of data are recommended for statistical accuracy. The signals are normalized to their DC voltages. This is designated by "N" preceding the spectral function listed below. The following functions should be generated:

(a) normalized power spectral densities (NPSD) of all detectors at the lowest detector section elevation or the average of more than one elevation including the lowest. Acquisition at the lowest and highest detector section elevations is preferred.

(b) normalized cross-power spectral densities (NCPSD), magnitude and phase, and coherence for all detectors from at least one elevation. Upper-to-lower pair CPSDs should be considered in cases of extra long fuel cycles or when anomalies are detected.

(c) a time history sample of all detectors.

The information in Nonmandatory Appendix D should also be considered for record length and sampling guidance.

Data should be acquired at full power during the first and last 30 to 90 effective full-power days (EFPD) of each cycle. Additional data collection such as at mid-cycle and partial power should also be considered.

5.5.3 In-Core Detectors. These detectors can be used to obtain information on fuel assembly vibration. The detectors can be located at grid or mid-span elevations for this purpose. When positioned at an elevation that is within the flux gradient near grids, vertical motion of the assembly, if any, can be inferred from the signals. In some designs, these detectors can also detect vibration of the in-core thimble at elevations within the fuel assembly.

Uranium-lined (fixed or movable) in-core detectors are used in some plants. These detectors have a good high frequency response, limited only by the electronics and cables. The noise signals do have a white noise background due to Campbelling (Knoll, 1989) that could mask lower level neutron noise signals. Core support barrel, fuel assembly, and thimble vibrations well above these levels have been observed.

Self-powered rhodium fixed in-core detectors are used in some plants. The large majority of the signal from this type of detector has a time constant of approximately 1 min. This is too slow to be practical for nuclear noise applications. A small fraction of the signal is fast. Glockler et al. (1986) provides vibration monitoring experience in Europe using in-core self-powered neutron detectors (SPND). Methods for dynamic compensation of rhodium SPNDs have been reported by Hoppe and Maletti (1992).

Some plants use plutonium self-powered fixed in-core detectors. The signals from these detectors have a good high frequency response and, therefore, their use for neutron noise monitoring is feasible.

The time history of the noise signal should be recorded at each location. All noise signal levels should be normalized to the steady state signal level. The steady state (or DC) voltages at each location should be documented at the beginning and end of the data acquisition.

NPSDs should be generated for all detector signals. If these are generated using a two-channel spectrum analyzer, selections of initial signals to be paired should be pairs that will provide information regarding

(a) modes that are confined to individual fuel assemblies

(b) modes in which the core support barrel participates

Data from selected in-core detector signals should be recorded with ex-core detectors. Modes dominated by fuel assembly and core support barrel motion commonly appear in in-core detector neutron noise signals. Cross-analysis of in-core detector pair signals, in-core/ex-core detector pair signals, and information on expected modal frequencies can support identification of these responses in the in-core signals. Data should be acquired during the first 30 to 90 EFPDs of the first fuel cycle of this program and each time a component design is changed.

Guidelines for the selection of elevations at which data should be acquired are provided below.

5.5.3.1 Movable Detectors. For each reactor having movable detectors, one or more detectors are inserted to a selected elevation. Data are acquired following the guidelines for record length given in para. 5.5.2. The detectors are moved to and data are acquired at several elevations. A data acquisition plan should be made to establish the core locations and elevations at which data should be acquired.

Since data is only obtained at one elevation at a time using movable detectors, information on the phase differences between elevations is not available. Expected fuel assembly vibration mode shapes can be used to assign likely relative phases to support interpretation.

5.5.3.2 Fixed Detectors. Data at all elevations of at least one thimble location should be acquired simultaneously.

5.5.4 Loose-Part Monitoring Accelerometers. The purpose of these accelerometers is to detect the impact of loose parts against the primary coolant system (Part 5). They have also been used in monitoring for degradation of thermal shield supports in some designs (see Kosaly). Correlating the vibration analysis results of the core support barrel and thermal shield system and the neutron noise data analyses with loose-part monitoring data analysis yields supporting and supplemental information on the condition of the thermal shield supports in those designs.

Some systems might permit acquisition of low frequency data. For these systems, reactor vessel and core support barrel vibration might also be detected by these accelerometers (depending on their locations, directions of sensitivity and signal filtering), providing an independent measurement where detectable.

Signal spectra from accelerometers mounted on the reactor vessel acquired at the same time as the ex-core detector signals should be included in the database. If the low frequency content of these signals has a suitable signal-to-noise ratio to permit detection of the expected vibration modes, the signals should be double-integrated to generate displacement spectra up to 50 Hz. In some systems, alarm discrimination may require the signals be high-pass filtered at 500 Hz or higher. However, the raw signal obtained directly from the accelerometers can be good down to 10 Hz.

5.6 Data Storage

Data should be stored to permit comparison of signal time history samples and NPSDs of each detector. The real-time correlation of all time histories of each detector type should be preserved. Nonmandatory Appendix D also provides guidance regarding storage of time history samples.

Ex-core and in-core detector data should be stored to permit generation of NCPSDs and coherence spectra between selected in-core pairs and selected in-core/ex-core pairs.

The data should preferably be stored in digital format either as ASCII files or any other file structure for which the program to convert to ASCII must be available and maintained for the life of the monitoring program. The documentation of para. 5.7 must be recorded at the beginning and, if applicable, at the end of data acquisition. This method of storage provides the best assurance that the data can be readily and accurately reproduced at a later time. Storage of data in nondegradable digital media such as optical disk or CD-ROM is preferred, though the data may be stored on digital or analog magnetic tapes. To prevent the data from being degraded by the external elements, including magnetic fields (such as the earth's magnetic field), over a length of 10 years to 20 years, these tapes should be protected by soft-iron cases. Storage of the original data time series is preferable to storing the spectral analysis results because it enables the data to be reanalyzed in the future.

5.7 Documentation

The following information should be recorded at the beginning of data collection. Any parameter (e.g., data and time, power level, boron concentration) that changes or may change during the time required to complete recording or analysis should also be recorded at the end of the data acquisition time.

(a) Data acquisition information that should be maintained for documentation is the following:

(1) plant name and unit number

(2) data and time of data acquisition

(3) plant conditions [power level, coolant flow rates, number of pumps operating, system temperatures and pressure, control rod positions, soluble boron concentrations, fuel burnup (EFPD), fuel cycle number, and any additional information needed for the interpretation of results]

(4) name of person or persons performing data acquisition and identification of data acquisition system or components

(5) identification of signals

(6) description of plant sensors including manufacturer, model number, serial number, and calibration or other identification such as plant part number

(7) description of signal conditioning equipment

(8) gains of amplifiers

(9) types of filters (e.g., low-pass, high-pass analog, digital) and cut-off frequencies

(10) DC voltages measured at the input of the signal-conditioning equipment (if available) or calculated from the power level

(11) log of observations or unusual occurrences, especially plant transients, during data acquisition

(b) Data recording information that should be maintained for documentation is the following:

(1) description of recorder

(2) gain setting of the recorder

(3) location of beginning and end of record and calibration signals

(4) identification of data recorded

(5) tape speed and bandwidth of recording for analog records or sampling rate, antialiasing filter set point, and file name for digital recording

6 DATA REVIEW

6.1 Initial Data Set

6.1.1 All Detector Signals in the Database. The initial data from the signals of all detectors included in the signal database should be reviewed for validity of the signals and the likely source of the dominant signal content. Data validity is established by reviewing the data acquisition documentation for completeness and consistency and by checking the signals for high 60 Hz noise or other electrical noise, overloads, signal spiking, loss of signal, and dynamic range. Data validation can be accomplished by visual examination of the time traces (strip charting) or by amplitude probability density (APD) analysis.

If this review results in significant uncertainty regarding the validity of the data, or its spectral content, another set should be recorded within 30 EFPDs of the original data acquisition. If the results of review of the second data set do not provide a reasonable basis for interpretation of the data, or if anomalous behavior of the core internals is considered likely, a specific plan should be established to support interpretation or identify the anomalous content.

6.1.2 Ex-Core Detectors. Ex-core detector signals data should be reviewed for the mode types and sources (e.g., core support barrel beam mode and thermal shield shell mode). The results should be compared to the expected responses obtained from one or more of the following:

(a) laboratory testing

(b) preoperational prototype vibration measurement programs

(c) fluid/structure analytical models

Guidelines for identification of core support barrel beam modes are included in Part 5. In some cases, the thermal shield and core support barrel system result in beam modes that should be similarly identified.

Ex-core neutron noise data are also used to monitor shell modes that are dominated by vibrations of the thermal shield or core support barrel. The lateral vibration shapes of these modes are shown in Fig. 2. Beam and shell modes can be identified by the phase differences between detector pairs.

The $n = 2$ mode usually has the larger shell mode response and should be identified in the data during the baseline phase of the program.

Figure 2 shows that for beam modes and $n = 3$ shell modes the cross-core detectors are out of phase, whereas for $n = 2$ shell modes the cross-core detectors are in phase. The vibration modes may be either in phase or out of phase with respect to cross-core detector pairs. Breathing modes in which the circular section remains circular are $n = 0$ shell modes. These modes are of higher frequency and lower amplitude and are not readily apparent in vibration plots. Phase separation techniques using the cross-power spectral density function for the cross-core detector pairs and their associated coherence or by analysis of sum and difference signals can also be used in the data reduction to assist in identification of modes (see Nonmandatory Appendix A).

6.1.3 In-Core Detectors. Data from these detectors are not required but may be used to supplement other data for diagnosis.

The signals of these detectors should be reviewed with the intent of identifying the beam modes of fuel assemblies and content that might be related to thimble motions and core support barrel vibration. Expected fuel assembly beam mode natural frequencies are available from the fuel designers. Fuel assembly vibration amplitudes are not readily deduced from these data. Fuel assembly motion related to core support barrel motion can be investigated by cross-correlation of in-core detector and ex-core detector noise signals.

6.1.4 Loose-Part Monitoring Accelerometers. The unfiltered or low-pass filtered signals of these data, if available, should be reviewed for low frequency content that might be related to core support barrel/reactor vessel system beam modes.

6.2 Subsequent Data Sets

6.2.1 All Detector Signals. The data should be reviewed for validity in accordance with para. 6.1.1 and for similarity with previous data. Ex-core data should be reviewed in accordance with para. 6.2.2.

6.2.2 Ex-Core Detector Signals. The following data is useful in relating changes in the data to changes associated with structural degradation:

(a) past variations when no structural degradation was found

(b) past variations when structural degradation was found

(c) experimental data with implanted defects

(d) analytical models with postulated structural degradation

(e) data from other plants that experienced structural degradation

It should be recognized that structural degradation must be significant before a detectable change in the monitored signals is produced. Loosening of one fastener on a joint that has multiple fasteners, for example, is not likely to be detectable.

Much of the information for detailed baseline studies and for studies of the structural integrity of the thermal shield is obtained from analysis of signals from neutron noise detector pairs, as discussed above. However, single channel information (such as auto spectra and narrowband/broadband rms displacements) give quick comparisons between the present and past data sets to establish a trend.

Conversion from neutron noise spectra to displacement spectra and rms displacements of the thermal shield follows the same equations given in Part 5. Information on conversion factors for thermal shield vibration is given in Kosaly. Since the conversion factors are only approximate, the computed rms displacements and displacement spectra should be used for comparison purposes only.

As the fuel cycle progresses, it is not uncommon to see the spectra peaks deteriorate slightly in some designs. This is caused by the relaxation of clamping forces, causing slight decreases in its stiffness and natural frequencies. As long as the change is small, it should not be a source of concern. In addition, burnup effects may cause increases in spectrum levels as the fuel cycle progresses that should be considered in establishing surveillance criteria. Reductions in the center frequencies of fuel assembly responses attributed to grid relaxation have also been reported (Sweeney et al., 1983).

Correlating the free vibration analysis results of the core support barrel/thermal shield system and the neutron noise data analyses with loose-part monitoring data analysis might support and supplement information on the condition of the thermal shield supports, as was demonstrated by Lubin et al. (1988).

PART 23
NONMANDATORY APPENDIX A
Discussion of Spectral Functions

This Appendix gives a brief description of various parameters (see Bendat and Piersol, 1971) used in baseline, surveillance, and diagnostic programs to identify core support barrel motion. It should be noted that all parameters are normalized to the operating power level (the DC value of the ex-core detector signal).

A-1 NORMALIZED POWER SPECTRAL DENSITY (NPSD)

The normalized power spectral density (the auto-power spectral density or APSD divided by the DC signal level squared) is a decomposition of a stochastic function into functions of frequency [see Fig. A-1, sketch (a)]. It provides a measure of the signal power (mean square level) within discrete frequency bands over specified frequency ranges, normalized to the reactor power level. Because the PSD is in units of Volts^2/Hz, and the NPSD is the PSD divided by the DC voltage squared, the units of the NPSD are 1/Hz. The sampling rate, sampling time, and sample size are governed by the relationships in Table 2 of Part 23.

A-2 NORMALIZED ROOT MEAN SQUARE OF THE SIGNAL

The normalized root mean square (nrms) value of the neutron noise signal is a measure of the amplitude of core support barrel motion. However, it may include systematic variations due to changing plant conditions (e.g., burnup), changes in $\beta_E FF$ (delayed neutron fraction) reactivity coefficients, and the like, which can contribute to a change in the nrms level. Since the nrms level is normalized to the DC level, it is dimensionless.

The rms value of the band f_1 to f_2 can be computed from NPSD as

$$(\text{nrms})^2 = \int_{f_1}^{f_2} \text{NPSD}\, df$$

NSPD can be used to calculate that portion of the total ex-core response related to core support barrel motion. Observed over an extended period of time, it provides a measure of changes in vibration.

A-3 NORMALIZED CROSS-POWER SPECTRAL DENSITY (NCPSD), COHERENCE (COH), AND PHASE (*N*)

A-3.1 Normalized Cross-Power Spectral Density (NCPSD)

The NCPSD (the cross-power spectral density or CPSD divided by the product of the DC level of the two signals) provides a descriptor of commonality between two encore detectors [see Fig. A-1, sketch (b)]. The ability of the NCPSD to discount noncoherent portions of the signal better defines the region of motion and, when used in conjunction with the coherence and phase, is preferred over the NSPD for establishing core support barrel motion. The rms value over frequency band f_1 to f_2 can be computed as the following:

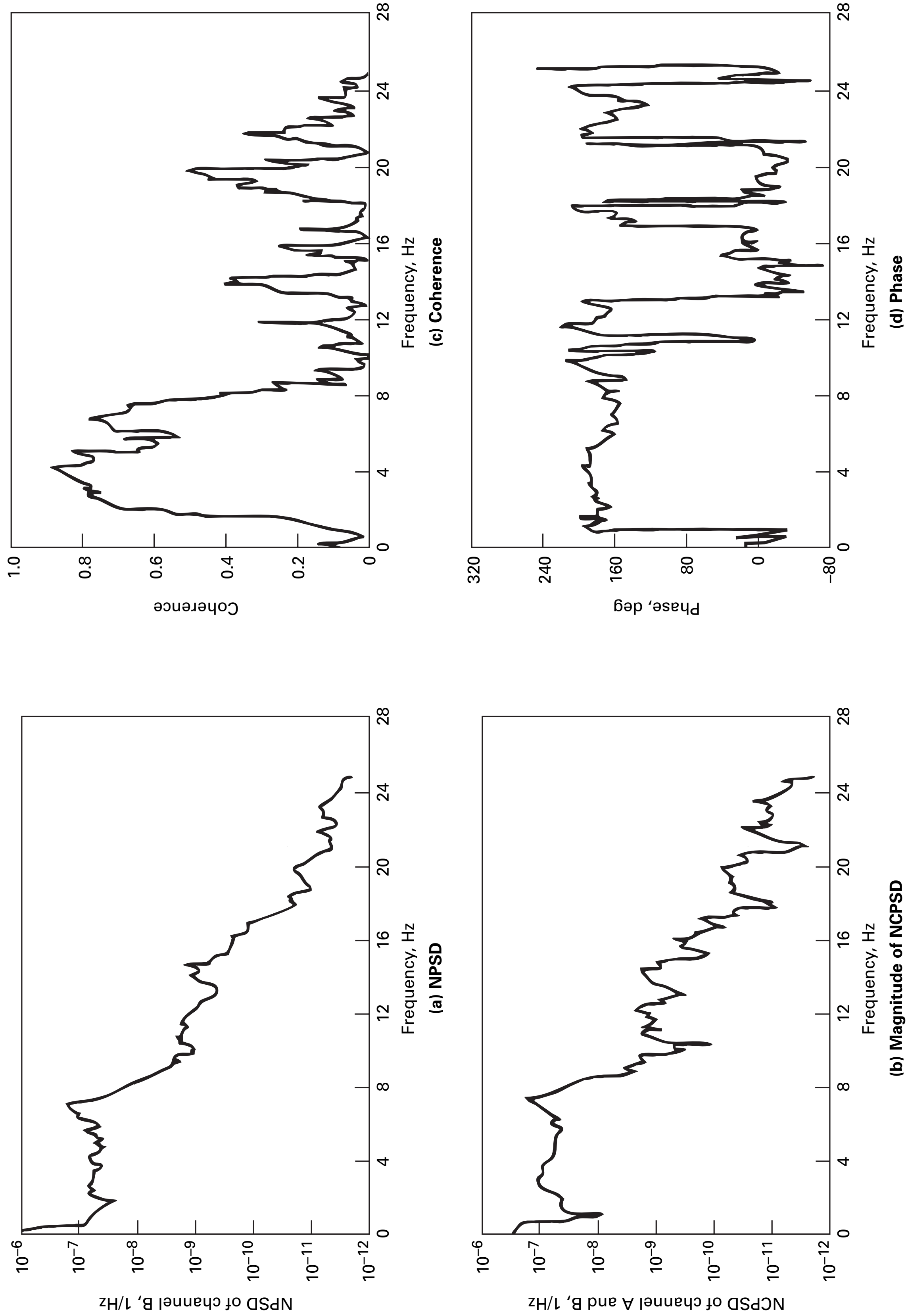
$$(\text{nrms})^2 = \int_{f_1}^{f_2} \text{NCPSD}\, df$$

The NCPSD is expressed as the product of signal voltages per product of DC voltages per unit of frequency, and has units of (1/Hz).

A-3.2 Coherence (COH) and Phase (*N*)

Although the NCPSD is a measure of the commonality between two variables, it is most convenient to represent the similar character in relative terms, relative to the individual signal NPSDs. This is done by calculating the coherence function. The coherence is defined as the ratio of the square of the magnitude of the NPSD to the product of the individual NPSDs and is bounded between zero and one [see Fig. A-1, sketch (c)]. If the coherence is one, the two signals are said to be fully coherent and, therefore, closely related. The corresponding phase data in this case are valid. Uncorrelated signals will have a coherence approaching zero, which means that the phase data is meaningless [see Fig. A-1, sketch (d)]. Coherence is dimensionless, while phase is expressed in degrees. Generally, for neutron noise signals, a coherence above 0.5 is considered good.

Fig. A-1 Different Spectral Functions



A-4 IN-PHASE AND OUT-OF-PHASE SIGNAL SEPARATION (MAYO, 1977)

Rigid-body lateral motion of the core and core support barrel, such as in the cantilever mode of vibration, produces coherent, out-of-phase (180 deg) signals between ex-core detectors located on opposite sides of the core. Geometric arguments can also be made that thermal shield and/or core support barrel shell modes produce either in-phase (0 deg) or out-of-phase signals between all ex-core detector pairs. Global reactivity fluctuations caused by mechanisms such as standing pressure waves or vertical core vibration produce in-phase signals between all detectors. Ex-core neutron noise signals typically contain multiple components with in-phase and out-of-phase relationships.

Overlapping in-phase and out-of-phase signals add or subtract from each other in the CPSD and coherence functions. Where this occurs, the CPSD has the phase of the larger signal while the magnitude of the CPSD and coherence are reduced due to partial cancellation. If the dominant signal component has a fairly smooth spectrum and the opposite phase signals have some structure, a peak in the lower magnitude process appears as a negative image in the magnitude of the CPSD and coherence. Where the magnitudes of the in-phase and out-of-phase signals are exactly equal, as at points where the spectrum transitions between dominant signal types, the magnitude of the CPSD and the coherence go to zero. This interference between in-phase and out-of-phase signal components increases the difficulty of interpreting the CPSD and coherence functions.

If the neutron noise signals are primarily composed of in-phase and out-of-phase noise sources, it is possible to obtain separate power spectral densities for the in-phase and out-of-phase signal components. This separation is no more than selective cancellation of the out-of-phase or in-phase signal components by adding or subtracting the noise signals from detectors located on opposite sides of the core.

The signals from two detectors that are responding to two independent processes, one in-phase and one out-of-phase between the detectors, can be represented as

$$S_1(t) = X(t) + Y(t)$$

$$S_2(t) = X(t) - Y(t)$$

Adding these signals cancels $Y(t)$ while reinforcing $X(t)$. Subtracting them cancels $X(t)$ while reinforcing $Y(t)$. This can be done with analog electronic circuits and the power spectral densities for X and Y can be calculated from the resulting sum and difference signals. In some cases, neutron noise analysis is performed by calculating the auto- and cross-power spectral densities, phase, and coherence functions without the possibility for prior addition or subtraction of the detector signals. In this situation, the power spectral densities of the in-phase and out-of-phase signal components can be calculated by the following:

where the phase of CPSD(ω) ≥ 0

$$\mathrm{PSD}Y(\omega) = \frac{1 - \left|\mathrm{COH}(\omega)\right|}{2}\,\mathrm{PSD}S_1(\omega)$$

$$\mathrm{PSD}X(\omega) = \frac{1 + \left|\mathrm{COH}(\omega)\right|}{2}\,\mathrm{PSD}S_1(\omega)$$

or where the phase of CPSD(ω) ≤ 0

$$\mathrm{PSD}Y(\omega) = \frac{1 + \left|\mathrm{COH}(\omega)\right|}{2}\,\mathrm{PSD}S_1(\omega)$$

$$\mathrm{PSD}X(\omega) = \frac{1 - \left|\mathrm{COH}(\omega)\right|}{2}\,\mathrm{PSD}S_1(\omega)$$

The PSD of either signal 1 or signal 2 can be used interchangeably in this form as it can be shown that

$$\mathrm{PSD}S_1(\omega) + \mathrm{PSD}S_2(\omega) = \mathrm{PSD}X(\omega) + \mathrm{PSD}Y(\omega)$$

The effectiveness of this separation of in-phase and out-of-phase signals depends on the absence of incoherent noise and noise sources with other than 0 deg and 180 deg phase between the detectors. This condition can be validated by the phase and coherence between $S_1(f)$ and $S_2(f)$. Where the measured signals are dominated by in-phase and out-of-phase processes, the measured phase will be either 0 deg or 180 deg. Also, as indicated by the equations for signal separation in the frequency domain, the separation will fail in the presence of dominant incoherent noise due to the coherence going to zero and so that

$$\mathrm{PSD}Y\,(\omega) = \frac{1}{2}\,\mathrm{PSD}S_i(\omega) = \mathrm{PSD}X\,(\omega)$$

The presence of a significant difference in the magnitude of PSDX (ω) and PSDY (ω) indicates the absence of incoherent noise. This condition and phase values of 0 deg and 180 deg between $S_1(\omega)$ and $S_2(\omega)$ indicate that the in-phase and out-of-phase signal separation process is valid.

In some cases, measurements have shown cross-core neutron noise signals to be remarkably free of incoherent noise and that the dominant signal components are either in-phase or out-of-phase over almost the entire frequency range of ex-core neutron noise. For these measurements, the phase-separated spectra have improved the observability of core support barrel cantilever and shell vibration modes and global reactivity noise. In other cases, and particularly in plants using low leakage fuel management and at later times in fuel cycles, incoherent noise has been present that substantially reduces the separation of in-phase and out-of-phase signal components. The quality of in-phase and out-of-phase signal separation should be examined in each application.

The separation of in-phase and out-of-phase signal components between neutron detectors that are not located on opposite sides of the core is of limited value. This is due to independence in the *X* and *Y* components of core support barrel cantilever mode vibration. Fully coherent signals for this vibration mode can be obtained only by detector pairs that are on directly opposite sides of the core where they respond to a single direction of motion.

A-5 REFERENCES

The following is a list of publications referenced in this Appendix.

Bendat, J. S., and Piersol, A. G., 1971, "Random Data Analysis and Measurement Procedures," Wiley Interscience, New York

Mayo, C. W., 1977, "Detailed Neutron Noise Analysis of Pressurized Water Reactor Internal Vibrations," Atomkernergie, Bd. 29, Lfg 1

PART 23
NONMANDATORY APPENDIX B
Supporting Information on Component Vibrations

B-1 IN-CORE DETECTOR THIMBLES

B-1.1 Introduction

Tubular thimbles guide the in-core detectors and provide a pressure boundary between the reactor coolant and the containment atmosphere. The thimbles are fixed in position when the plant is operating. The detectors are either fixed during operation or travel in and out of the thimbles during use. The outside of the thimble has a nominal clearance with the guide tube in the fuel assembly and the detector has a nominal clearance with the inside of the thimbles. Experience indicates that the support points between the thimble and the guide tube and between the thimble and the detector probably have some variation from thimble to thimble.

The thimble length permits the detectors to reach the top of the core for mapping of core power. For this purpose, several detectors can be inserted simultaneously. Switching is provided outside of the reactor vessel so that all of the locations in the core can be mapped by measurements with several groups of thimbles.

Wear of the thimble wall due to vibration of the thimble has occurred. This wear is monitored by eddy current inspection. In some cases, the noise signals of in-core detectors can be used to detect thimble vibration as discussed below.

B-1.2 Detection of Thimble Vibration Using In-core Detector Neutron Noise

Vibration of the thimble and detector causes the detector to move through a flux gradient. If the thimble vibration mode includes motion at fuel elevations, motion can be detected by acquisition and analysis of in-core neutron noise signals using the same techniques as those that are used for detecting structural vibration from ex-core signals. Although a broad database is not available, this technique has been used to compare the vibration levels for thimbles fitted with various wear mitigation devices (Trenty, 1987). On this basis, the neutron noise method could be used to identify very active locations.

B-2 BAFFLE JETTING

B-2.1 Introduction

The primary flow path for "down flow" PWR internals is through the reactor coolant system (RCS) inlet nozzles, down the outside of the lower core support barrel (CSB) to the bottom of the reactor vessel (RV), and up through the lower fuel assembly area. In addition to this, in some PWR designs, a secondary flow path is generated by holes through the CSB below the top former plate, connecting the main RCS flow at the bottom of the RV. Baffle plates exist in an annular region that is a transition region between the outer fuel assembly pattern and the round CSB. Because of the pressure drop of the main RCS channel through the core, a differential pressure exists between the core region and the region made up of the core support barrel/baffle plates. Because of the small gaps that exist in the joints between the individual baffle plates, the differential pressure causes a jet of water to flow horizontally into the core region. If the gap and the jet are sufficiently large, this jet of water is known as "baffle jetting" and can cause the outer fuel pins to vibrate excessively.

B-2.2 Data Acquisition

Signals monitored must include the signals from a "prompt in-core detector" in the fuel assembly suspected of baffle jetting.

The in-core detector elevation should be in the upper half of the fuel assembly suspected of baffle jetting. The data acquired should include the in-core signals from an interior fuel assembly, preferably several interior and peripheral in-core signals simultaneously.

The data acquired must also include the ex-core neutron detector in the quadrant of suspected baffle jetting and should include all ex-core upper and lower chambers, preferably all ex-core upper and lower chambers simultaneously with the in-core detectors.

Because of electrical noises inherent in power plant signals, both in-core and ex-core signals need to be filtered prior to acquisition (see Table 1). The frequency set points for the filters during data acquisition should not interfere with the frequency range of interest. See para. 5 for more details.

B-2.3 Data Diagnosis

(a) Data reduction should include the generation of the following functions:

(1) power spectral density (PSD)
(2) cross-power spectral density (CPSD)
(3) coherence (COH)

(4) phase (PHA)

It is recommended that 100 blocks of data be averaged to reduce statistical uncertainties.

(b) The functions listed above should be generated for the following combinations of signals:

(1) The in-core signals from the upper half of fuel assemblies of interest and the ex-core upper section signals from the quadrant closest to the suspected baffle jetting should be correlated and compared.

(2) The in-core signals from an interior fuel assembly and the in-core signals of the fuel assembly in which baffle jetting is suspected.

B-3 FUEL ASSEMBLY VIBRATIONS

B-3.1 Introduction

A PWR fuel assembly exists in an environment where flowing water conditions passing through the fuel assembly cause the fuel assembly to vibrate. In-core detector signals can provide information on this vibration.

B-3.2 Data Acquisition

In-core detector data should be acquired at several axial locations in the fuel assemblies of direct interest and in several reference assemblies.

If permitted by the detector configuration, data from several axial levels should be acquired simultaneously within the same assembly, as well as from the reference assemblies.

As a minimum, simultaneous recording of the center in-core signal and the signal of the detector closest to each ex-core detector should be recorded. Ex-core detector signals in the quadrants of the fuel assemblies of interest should be acquired with at least a selected sample of the in-core signals.

B-3.3 Data Diagnosis

Data analysis and interpretation should be done in accordance with para. B-2.3. For detection of fuel assembly vibration modes, the expected mode shapes and natural frequencies should be available during data acquisition and diagnostic phases.

Industry experience has shown that the lower elevation in-core signals and lower section ex-core signals are influenced more strongly by the primary beam mode vibration of the core support barrel. Upper elevation in-core signals and the upper section ex-core signals will more readily show the fuel assembly modes. If in-core detector data from several elevations cannot be acquired simultaneously, the relative amplitudes of a frequency peak or rms level over a frequency range from data acquired at different times can be compared to the expected relative amplitude of the fuel assembly mode expected near that frequency to support interpretation.

B-4 REFERENCES

The following publication is referenced in this Appendix.

Trenty, A., et al., 1987, "Thimble Vibration Analysis and Monitoring on 1300 and 900 MW Reactors Using Accelerometers and Incore Neutron Noise," Progress in Nuclear Energy, Vol. 21, Proceedings of the Fifth Specialists Meeting on Reactor Noise, Munich, F.R.G., 12–16.

PART 23
NONMANDATORY APPENDIX C
Pump-Induced Vibrations

C-1 INTRODUCTION

Occasionally ex-core neutron noise signals contain information generated by reactor coolant pump behavior. An understanding of how reactor coolant pumps can influence ex-core signals is required to properly interpret the ex-core neutron noise data and may assist the detection of pump anomalies. The purpose of this Appendix is to present sample traces that demonstrate this process.

C-2 CASE STUDY 1: COOLANT PUMP OPERATION CHARACTERISTICS

(a) The plan view of a two loop PWR plant and the relative location of its ex-core neutron noise detectors is shown in Fig. C-1. A baseline set of ex-core data (data set 1) was acquired during a fuel cycle for the three pairs of cross-core detectors: A-D, B-C, and X-Y. The results of the data analysis for each pair of cross-core detectors include normalized spectral densities (NPSD), normalized cross-NPSDs (NCPSD), phase-separated NCPSDs, coherence (COH), and phase (PHA). Figure C-2 shows a representative out-of-phase (180 deg) NCPSD. The reactor coolant pump rotor speed is clearly indicated by a narrow banded peak at 15 Hz.

Later during the same fuel cycle a similar set of excore data (data set 2) was acquired and reduced. Comparison of data sets 1 and 2 indicates the following:

(1) A narrow-banded, out-of-phase peak at 5.2 Hz appeared in the A-D and B-C cross-core detector data of data set 2 (see Fig. C-3).

(2) A similar peak did not appear in the X-Y data (see Fig. C-4).

(3) At other frequencies, the data was consistent except for amplitude differences arising from burn-up–related effects.

At the same time that the 5.2 Hz peak was observed, the loose-part monitoring (LPM) triaxial accelerometers mounted on top of reactor coolant pump 2A (see Fig. C-1) measured a predominant increased response at 5.2 Hz. The increased pump excitation was due to oil whip, a self-excited vibration, in the pump bearing. Mitchell (1993) discusses the causes and symptoms of oil whip, which causes vibration at frequencies less than half the rotor speed, when there is a critical speed below half the rotor speed. Since the rotor speed is 15 Hz, and a dominant structural natural frequency of the pump was calculated to be 5.2 Hz, oil whip should occur at 5.2 Hz.

Therefore, oil whip excited the pump giving rise to the increased acceleration levels measured and the unusual signals in the ex-core data.

Figure C-2 shows the typical out-of-phase peak of the pump rotor speed that appears in all cross ex-core detector data. In Fig. C-3, out-of-phase NCPSDs from data set 2 for detector pairs A-D and B-C are shown. A comparison of the rotor speed (15 Hz) peak with the 5.2 Hz peak show them both to be narrow band.

Fluid-borne and mechanical excitation originating at pump 2A excites the CSB asymmetrically. Asymmetric excitation produces lateral motion in the CSB that is dominant in one transverse direction. The 5.2 Hz peak appears in the out-of-phase NCPSD of detector pairs A-D and B-C and does not appear in the X-Y detector pair (compare Fig. C-3 with Fig. C-4) The fact that cross-core detector pairs A-D and B-C exhibit the 5.2 Hz peak, whereas detector pair X-Y does not, tends to corroborate the CSB lateral motion due to pump 2A.

During the next outage, pump 2A was replaced. A succeeding set of ex-core data was acquired and reduced. The NCPSDs of detector pairs A-D and B-C indicated the 5.2 Hz peak had been eliminated. In addition, the LPM accelerometer readings returned to nominal levels.

(b) This case study demonstrates the following:

(1) Characteristics of neutron signatures can be related to specific physical phenomena such as a change in pump operating conditions.

(2) Natural frequencies of plant structures, as determined from analyses and/or test data, for example the pump, provide necessary information to interpret the neutron noise signature.

(3) Correlating neutron noise data with LPM data provides supplemental information to enhance data evaluation of both monitoring system.

C-3 CASE STUDY 2: SPACE-TIME BEATING OF COOLANT PUMPS IN A MULTI-LOOP PWR PLANT

A typical PWR plant consists of two to four loops, each loop driven by a coolant pump. Because the design and loading of these pumps are very similar, they run at very nearly the same speeds. As the impeller rotates, it generates acoustic pressure waves at the blade passing frequency and its higher harmonics. Thus, a coolant pump with a five-blade impeller rotating at 1,200 rpm will generate acoustic waves at frequencies of 100, 200, 300 (and so on) Hz as well as at the fundamental shaft rotation frequency of 20 Hz. These acoustic waves propagate along the coolant conduits into the reactor vessel internals and induce pressure on the core support barrel or thermal shield. Under idealized conditions when the impeller rotational speeds are identical, the phase relationship of the acoustic pressure induced by the coolant pumps in the different loops will be constant, and the reactor core will be biased to one side by the resultant force. In the actual situation the pumps rotate at minutely different speeds. As a result, the acoustic waves generated by the different coolant pumps are minutely different in frequencies. This gives rise to multi-pump beating very much like the sound generated by a multi-engine, propeller-driven airplane. The alternate constructive and destructive interference of the acoustic pressure waves gives rise to a changing net lateral force acting on the reactor core support barrel or thermal shield. Since this net force not only changes in magnitude, but also in direction, with time, the resultant core motion is not only vibratory but also precessional.

This phenomenon was analytically predicted by Au-Yang (1979) and was observed in actual neutron noise data. Figure C-5, reproduced from Wach and Sunder (1977), shows the precessional motion of the core of a reactor in a multi-loop PWR plant in Europe. Under normal conditions, the vibratory amplitudes are very small and will not cause any fatigue damage to the internal components.

C-4 REFERENCES

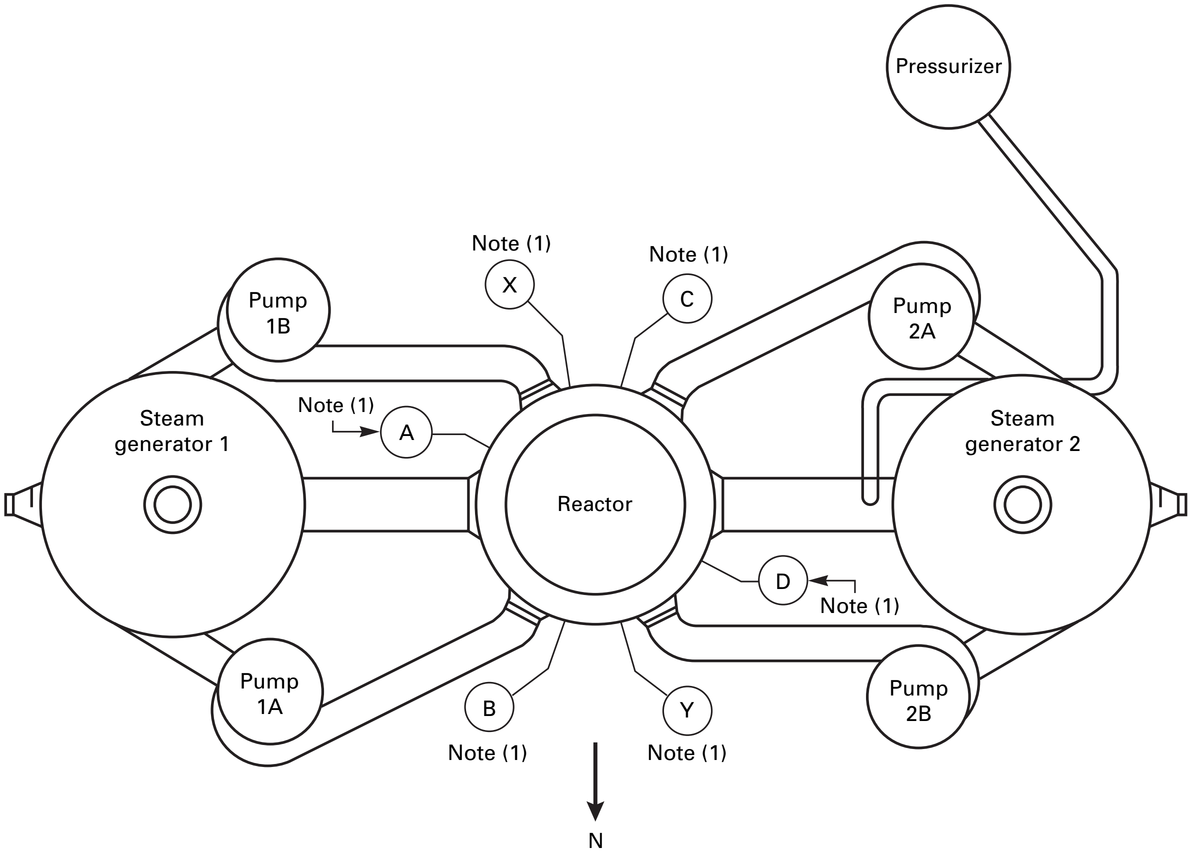
The following is a list of publications referenced in this Appendix.

Au-Yang, M. K. 1979, “Pump-Induced Acoustic Pressure Distribution in an Annular Cavity Bounded by Rigid Walls, “Journal of Sound and Vibration Vol. 62,” pp. 577–591

Mitchell, J. S., 1993, “Machinery Analysis and Monitoring Second Edition,” p. 176, Pennwell Books

Wach, D. and Sunder, R., 1977, “Improved PWR Neutron Noise Interpretation Based on Detailed Vibration Analysis,” paper presented at the Second Specialists’ Meeting on Reactor Noise, Tennessee

Fig. C-1 Reactor Coolant System Arrangement — Plan View



GENERAL NOTE: See para. C-2.

NOTE:

(1) Ex-core detector location.

Fig. C-2 Data Set I, 180 deg Phase NCPSD, A–D

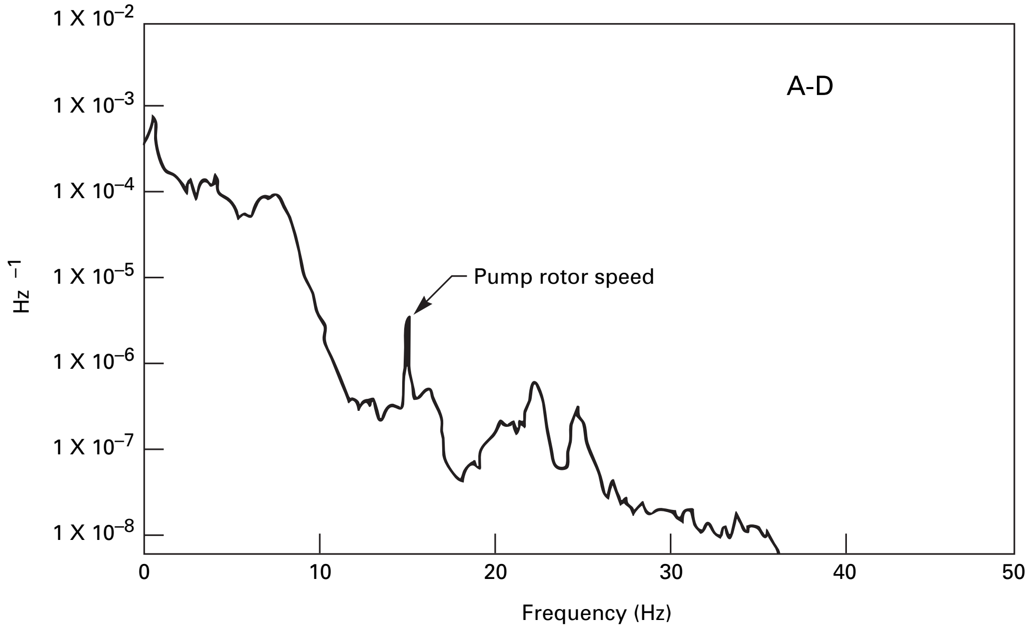
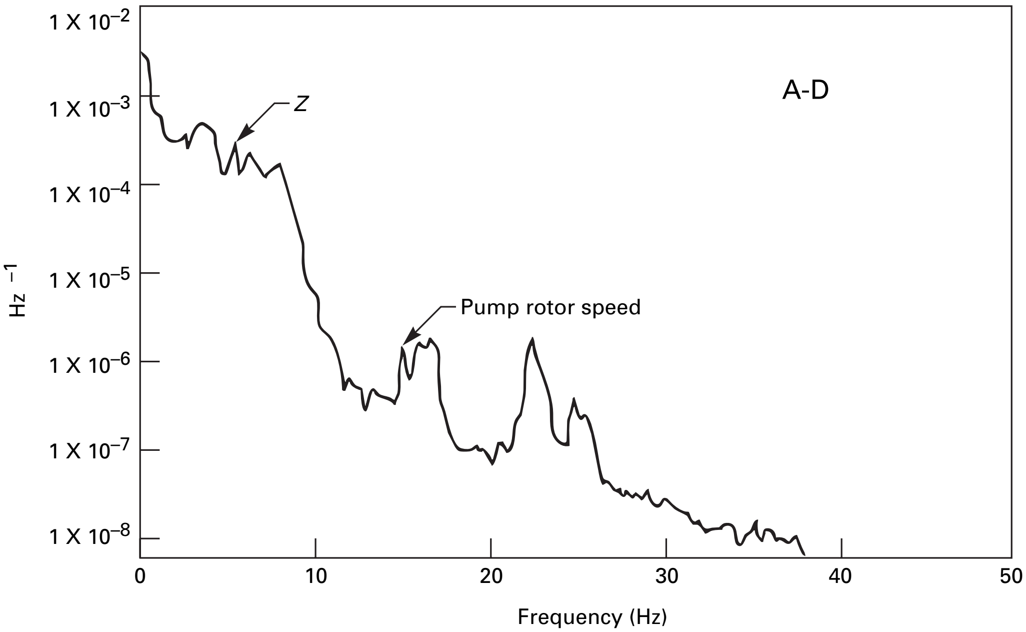
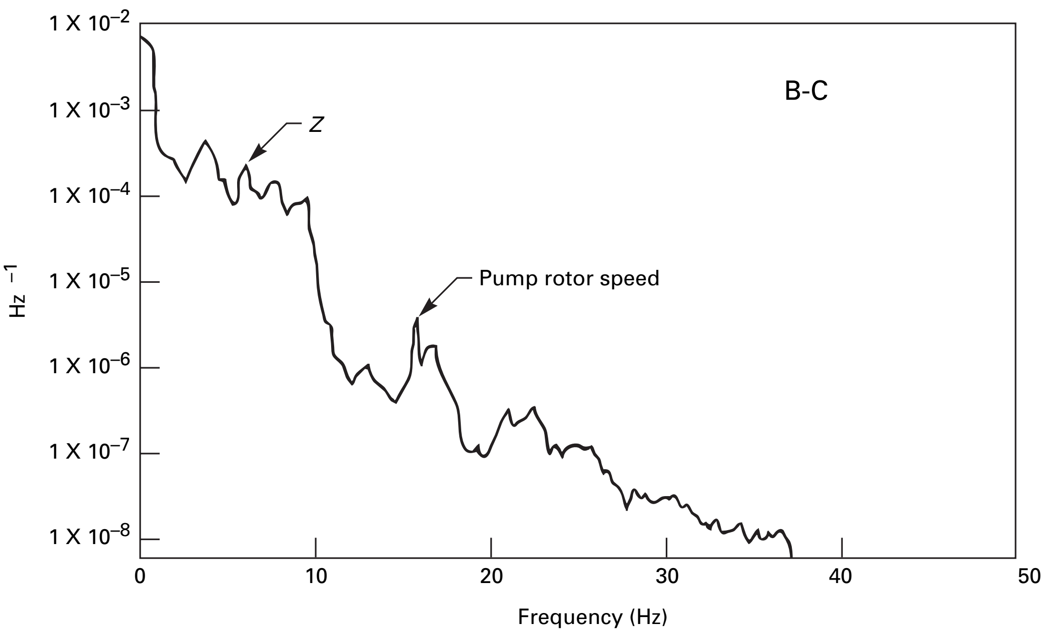


Fig. C-3 Data Set II, 180 deg NCPSD, A–D and B–C



(a) A-D Cross Core Detector Data



(b) B-C Cross Core Detector Data

Fig. C-4 180 deg Phase NCPSD, X–Y

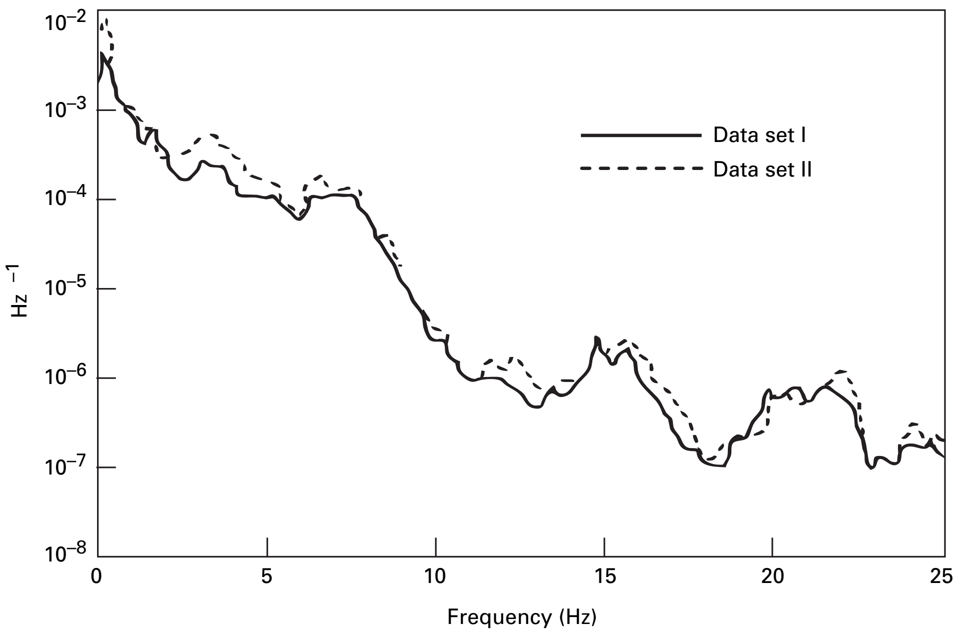
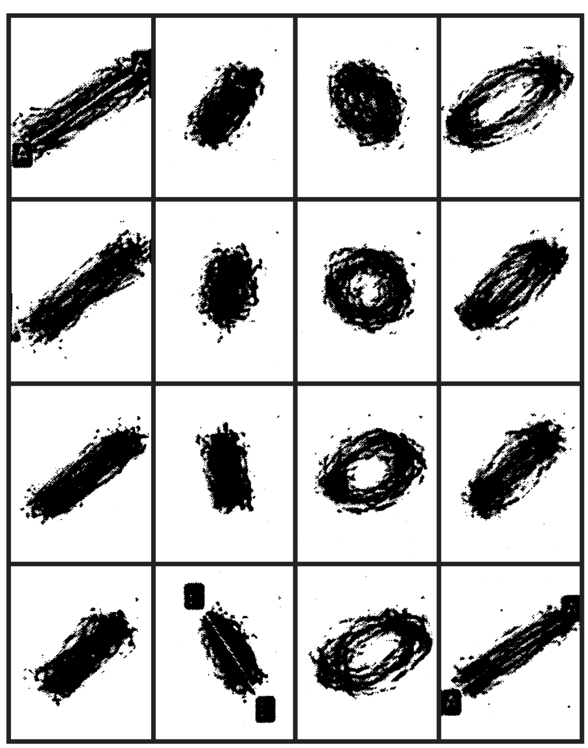


Fig. C-5 Lissajous Figure of Ex-Core Neutron Noise Data Showing Motion of Reactor Core in a Multi-Loop Plant



GENERAL NOTE: See para. C-3.

PART 23
NONMANDATORY APPENDIX D
Sampling Rate and Length of Data Record Requirement to Resolve a Spectral Peak

One of the needs from a stored time history that has been recorded digitally could be resolution of a spectral peak. This could be needed to ascertain the bandwidth of the peak so that, for example, the apparent damping of a structural model could be estimated.

An example, using a peak intended to be narrow, is given as follows:

Expected natural frequency: 10 Hz
Expected damping ratio: 0.005
Required accuracy in damping ratio: 20%
Required statistical accuracy: 100 averages

Question: What should be the sampling rate? How long a time record is needed?

Solution: Damping ratio is related to the half-power width of the resonance peak by the relationship,

$$\zeta = \delta f / 2 f_o$$

where f_o is the natural frequency and δf is the bandwidth at half power; we have

$$\delta f = 2 f_o \mathbf{s} = 2 \times 0.005 = 0.1 \text{ Hz}$$

To determine the damping ratio within an accuracy of 20%, we need a frequency resolution of

$$\triangle f = 0.02 \text{ Hz}$$

This will give 10 points to represent this peak. Application of the Nyquist sampling theorem to the 10 Hz expected natural frequency indicates the required minimum sampling rate for the wave form is 20 samples/sec. In practice some margin is necessary. As an example, the following sampling rate is selected:

$$f_s = 30/S$$

By comparison, the compact disc format uses a sampling rate of 44,100/S to ensure reproduction of musical notes up to 20,000 Hz. So here we have more margin than the CD. The sampling time interval $\triangle T$ is the inverse of the sampling frequency. Thus,

$$\triangle T = 1/f_s = 1/30 \text{ sec}$$

Most wave form and frequency analyzers use the Fast Fourier Transform (FFT) algorithm, for which the number of data points to be transformed each time must be 2^k where k is an integer. As an example, with a block size of

$$n = 2^{10} = 1{,}024 \text{ points}$$

The length of time record per block is,

$$\delta T = n \Delta T = 0124 \times 1/30 = 34.13 \text{ sec}$$

After FFT, we get 512 points on the $+f$ side and 512 points on the $-f$ side of the spectral curve, which is symmetrical about $f = 0$. Only the $+f$ side is useful to us. The maximum frequency we get is called the Nyquist frequency, and is equal to one half the sampling frequency (15 Hz in the present case), and we have 512 + 1 = 513 points to represent it. Thus, the frequency resolution is

$$\Delta f = 15/512 = 0.029 \text{ Hz}$$

and in general

$$\Delta f \, \Delta T = 1/n$$

Since 0.029 Hz is larger than what is required to adequately define the spectral peak, we have to increase the number of data points, n, per block. The next step up is to choose

$$n = 2^{11} = 2{,}048$$

Keeping the same sampling rate $\Delta t = 1/30$ sec, we have now after FFT

$$\Delta f = 1/(n\Delta T) = 1 / (2{,}048 \times 1/30) = 0.0146 \text{ Hz}$$

This is fine to define the resonance peak, as originally determined. But the time record per block is now

$$\delta T = 2{,}048 \times 1/30 \text{ sec}$$

and we need 100 blocks of this to achieve the required statistical accuracy. The total length of time record we need is

$$T = Nn\Delta T = 100 \times 2{,}048/30 = 6{,}827 \text{ sec} = 1.9 \text{ hr}$$

If we use 12-bit words (this will give us a dynamic range of 72 dB), the total number of bits per channel of data per test record is

$$204{,}800 \times 12 = 2.46 \text{ M bit} = 1.23 \text{ M byte}$$

Most ex-core neutron noise detector system have between four to six sensors, bringing the total number of bytes per test record between 5 M to 10 M. This is still within the capability of modern digital acquisition equipment.

The above example shows that low frequency tests involve very long time records. One way to economize is to sacrifice statistical accuracy. One hundred averages correspond to a normalized error of 0.1. In practice, more than 100 averages would not significantly enhance the accuracy. Since normalized error is

$$\epsilon = 1/\sqrt{N}$$

we can drop the number of averages to 64 without sacrificing a lot of statistical accuracy while cutting the test time by 40%.

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