

ASME OM-2022
(Revision of ASME OM-2020)

Operation and Maintenance of Nuclear Power Plants

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AN AMERICAN NATIONAL STANDARD



The American Society of
Mechanical Engineers

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**The American Society of
Mechanical Engineers**

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CONTENTS

Foreword	xiv
Committee Roster	xv
Correspondence With the OM Committee	xix
Preface	xxi
ASME OM Cases and Applicability Index for ASME OM Cases	xxiii
Cross-Referencing and Stylistic Changes in ASME OM	xxiv
Summary of Changes	xxv
Division 1	
Subsection ISTA	
ISTA-1000	1
ISTA-2000	2
ISTA-3000	3
ISTA-4000	5
ISTA-5000	5
ISTA-6000	5
ISTA-7000	5
ISTA-8000	5
ISTA-9000	5
Subsection ISTB	
ISTB-1000	7
ISTB-2000	7
ISTB-3000	7
ISTB-4000	11
ISTB-5000	11
ISTB-6000	18
ISTB-7000	19
ISTB-8000	19
ISTB-9000	19
Subsection ISTC	
ISTC-1000	20
ISTC-2000	20
ISTC-3000	21
ISTC-4000	25
ISTC-5000	25
ISTC-6000	29
ISTC-7000	29

ISTC-8000	To Be Provided at a Later Date	29
ISTC-9000	Records and Reports	29
Subsection ISTD	Preservice and Inservice Requirements for Dynamic Restraints (Snubbers) in Water-Cooled Reactor Nuclear Power Plants	30
ISTD-1000	Introduction	30
ISTD-2000	Definitions	31
ISTD-3000	General Requirements	32
ISTD-4000	Specific Examination Requirements	32
ISTD-5000	Specific Testing Requirements	34
ISTD-6000	Service Life Monitoring Requirements	39
ISTD-7000	To Be Provided at a Later Date	40
ISTD-8000	To Be Provided at a Later Date	40
ISTD-9000	Records and Reports	40
Subsection ISTE	Risk-Informed Inservice Testing of Components in Water-Cooled Reactor Nuclear Power Plants	42
ISTE-1000	Introduction	42
ISTE-2000	Supplemental Definitions	42
ISTE-3000	General Requirements	43
ISTE-4000	Specific Component Categorization Requirements	44
ISTE-5000	Specific Testing Requirements	47
ISTE-6000	Monitoring, Analysis, and Evaluation	49
ISTE-7000	To Be Provided at a Later Date	49
ISTE-8000	To Be Provided at a Later Date	49
ISTE-9000	Records and Reports	49
Subsection ISTF	Inservice Testing of Pumps in Water-Cooled Reactor Nuclear Power Plants — Post-2000 Plants	50
ISTF-1000	Introduction	50
ISTF-2000	Supplemental Definitions	50
ISTF-3000	General Testing Requirements	50
ISTF-4000	To Be Provided at a Later Date	53
ISTF-5000	Specific Testing Requirements	53
ISTF-6000	Monitoring, Analysis, and Evaluation	56
ISTF-7000	To Be Provided at a Later Date	58
ISTF-8000	To Be Provided at a Later Date	58
ISTF-9000	Records and Reports	58
Mandatory Appendix I	Inservice Testing of Pressure Relief Devices in Water-Cooled Reactor Nuclear Power Plants	59
Mandatory Appendix II	Check Valve Condition-Monitoring Program	69
Mandatory Appendix III	Preservice and Inservice Testing of Active Electric Motor-Operated Valve Assemblies in Water-Cooled Reactor Nuclear Power Plants	72
Mandatory Appendix IV	Preservice and Inservice Testing of Active Pneumatically Operated Valve Assemblies in Nuclear Reactor Power Plants	77
Nonmandatory Appendix A	Preparation of Test Plans	83
Supplement to Nonmandatory Appendix A		85
Nonmandatory Appendix B	Dynamic Restraint Examination Checklist Items	86
Nonmandatory Appendix C	Dynamic Restraint Design and Operating Information	87

Nonmandatory Appendix D	Comparison of Sampling Plans for Inservice Testing of Dynamic Restraints	88
Nonmandatory Appendix E	Flowcharts for 10% and 37 Snubber Testing Plans	89
Nonmandatory Appendix F	Dynamic Restraints (Snubbers) Service Life Monitoring Methods	92
Nonmandatory Appendix G	Application of Table ISTD-4252-1, Snubber Visual Examination	94
Nonmandatory Appendix H	Test Parameters and Methods	96
Nonmandatory Appendix J	Check Valve Testing Following Valve Reassembly	98
Nonmandatory Appendix K	Sample List of Component Deterministic Considerations	100
Nonmandatory Appendix L	Acceptance Guidelines	101
Nonmandatory Appendix M	Design Guidance for Nuclear Power Plant Systems and Component Testing	104
Division 2	OM Standards	110
Part 2	Performance Testing of Closed Cooling Water Systems in Light-Water Reactor Power Plants	110
Part 3	Vibration Testing of Piping Systems	111
1	Scope	111
2	Definitions	111
3	General Requirements	112
4	Visual Inspection Method	116
5	Simplified Method for Qualifying Piping Systems	116
6	Rigorous Verification Method for Steady-State and Transient Vibration	121
7	Instrumentation and Vibration Measurement Requirements	122
8	Corrective Action	123
Nonmandatory Appendix A	Instrumentation and Measurement Guidelines	124
Nonmandatory Appendix B	Data Processing Methods	128
Nonmandatory Appendix C	Vibration Analysis Methods	134
Nonmandatory Appendix D	Velocity Criterion	136
Nonmandatory Appendix E	Excitation Mechanisms, Responses, and Corrective Actions	137
Nonmandatory Appendix F	Flowchart — Outline of Vibration Qualification of Piping Systems	140
Nonmandatory Appendix G	Qualitative Evaluations	142
Nonmandatory Appendix H	Guidance for Monitoring Piping Steady-State Vibration Per Vibration Monitoring Group 2	143
Nonmandatory Appendix I	Acceleration Limits for Small Branch Piping	148
Part 5	Inservice Monitoring of Core Support Barrel Axial Preload in Pressurized Water Reactor Power Plants	150
1	Purpose and Scope	150
2	Background	150
3	Program Description	152
4	Baseline Phase	152
5	Surveillance Phase	154
6	Diagnostic Phase	154
Nonmandatory Appendix A	Theoretical Basis	156
Nonmandatory Appendix B	Data Reduction Techniques	158
Nonmandatory Appendix C	Data Acquisition and Reduction	160
Nonmandatory Appendix D	Data Evaluation	163

Nonmandatory Appendix E	Guidelines for Evaluating Baseline Signal Deviations	167
Nonmandatory Appendix F	Correlation of rms Amplitude of the Ex-Core Signal (Percent Noise) and Amplitude of Core Barrel Motion	172
Nonmandatory Appendix G	Bibliography	173
Part 7	Thermal Expansion Testing of Nuclear Power Plant Piping Systems	174
1	Scope	174
2	Definitions	174
3	General Requirements	175
4	Reconciliation Methods	176
5	Corrective Action	177
6	Instrumentation Requirements for Thermal Expansion Measurement . .	179
Nonmandatory Appendix A	TEMS Instrumentation and Equipment Guidelines	181
Nonmandatory Appendix B	Thermal Stratification and Thermal Transients	184
Part 12	Loose Part Monitoring in Water-Cooled Reactor Nuclear Power Plants	187
1	Introduction	187
2	Definitions	187
3	References	189
4	Equipment	189
5	Program Elements	198
6	Documentation	202
Nonmandatory Appendix A	References	204
Part 16	Performance Testing and Monitoring of Standby Diesel Generator Systems in Water-Cooled Reactor Nuclear Power Plants	205
1	Introduction	205
2	Nonoperating Checks	208
3	Testing	208
4	Inservice Monitoring of Component Operating and Standby Conditions	212
5	Other Condition-Monitoring Methods/Guidelines	214
6	Alarm and Shutdown During Tests	217
7	Diesel Generator Operating Data and Records	217
Nonmandatory Appendix A	Post-Major Maintenance Test Data	218
Nonmandatory Appendix B	Functional/Inservice Test Data	219
Nonmandatory Appendix C	Data Trending Examples	220
Part 21	Inservice Performance Testing of Heat Exchangers in Water-Cooled Reactor Nuclear Power Plants	226
1	Introduction	226
2	Definitions	226
3	References	228
4	Selection and Prioritization of Heat Exchangers	229
5	Basic Requirements	229
6	Selection of Methods	230
7	Testing and Monitoring Conditions	237
8	Errors, Sensitivities, and Uncertainties	239
9	Acceptance Criteria	240

10	Corrective Action	241
11	Records and Record Keeping	241
Nonmandatory Appendix A	Diagnostics	243
Nonmandatory Appendix B	Precautions	246
Nonmandatory Appendix C	Examples	249
Part 24	Reactor Coolant and Recirculation Pump Condition Monitoring . .	281
1	Introduction	281
2	Definitions	281
3	References	283
4	Machine Faults	283
5	Vibration, Axial Position, and Bearing Temperature Monitoring Equipment	283
6	Vibration Data Analysis System Requirements	286
7	Seal Monitoring	288
8	Vibration, Axial Position, and Bearing Temperature Monitoring	289
9	Alarm Settings	291
10	Analysis and Diagnostics	292
11	Additional Technologies	293
12	Other	294
Nonmandatory Appendix A	References	295
Nonmandatory Appendix B	Thermography	296
Nonmandatory Appendix C	Lube Oil Analysis	297
Nonmandatory Appendix D	Motor Current Signature Analysis	298
Nonmandatory Appendix E	Loose Parts Monitoring	299
Part 25	Performance Testing of Emergency Core Cooling Systems in Light-Water Reactor Power Plants	300
Part 26	Determination of Reactor Coolant Temperature From Diverse Measurements	301
1	Introduction	301
2	Definitions	301
3	References	302
4	Requirements	302
5	Develop Test Procedures and Perform Testing	303
6	Documentation	304
Nonmandatory Appendix A	Measurement Equipment Uncertainties	305
Part 28	Standard for Performance Testing of Systems in Water-Cooled Reactor Nuclear Power Plants	306
1	Introduction	306
2	Definitions	306
3	References	307
4	General Testing Requirements	307
5	Specific Testing Requirements	312
6	Evaluate Test Data	312
7	Documentation	313
Mandatory Appendix I	Specific Testing Requirements of Emergency Core Cooling Systems in BWR Power Plants	314

Mandatory Appendix II	Specific Testing Requirements of Emergency Core Cooling Systems in PWR Power Plants	318
Mandatory Appendix III	Specific Testing Requirements of Auxiliary or Emergency Feedwater Systems in Water-Cooled Reactor Nuclear Power Plants	322
Mandatory Appendix IV	Specific Testing Requirements of Closed Cooling Water Systems in Water-Cooled Reactor Nuclear Power Plants	324
Mandatory Appendix V	Specific Testing Requirements of Emergency Service Water Systems in Water-Cooled Reactor Nuclear Power Plants (Open Cooling Water Systems)	328
Mandatory Appendix VI	Specific Testing Requirements of Instrument Air Systems in Water-Cooled Reactor Nuclear Power Plants	331
Nonmandatory Appendix A	Industry Guidance	336
Nonmandatory Appendix B	Guidance for Testing Certain System Characteristics	340
Nonmandatory Appendix C	Measurement Accuracy of System Characteristics	346
Division 3	OM Guides	353
Part 11	Vibration Testing and Assessment of Heat Exchangers	353
1	Introduction	353
2	Definitions	353
3	References	353
4	Background Description	353
5	Selection of Equipment to Be Tested	354
6	Selection of Test Method	355
7	Test Requirements	356
8	Test Conditions	363
9	Documentation	363
10	Precautions	364
Nonmandatory Appendix A	Causes of Vibration	365
Nonmandatory Appendix B	Methods for Comparative Evaluation of Fluidelastic and Turbulence-Induced Vibration	369
Nonmandatory Appendix C	Test Guidelines for Dynamic Characterization of Tubes	372
Nonmandatory Appendix D	External Vibration Surveys	373
Nonmandatory Appendix E	Detection Methods and Data Interpretation	374
Nonmandatory Appendix F	Vibration Acceptance Guidelines	389
Nonmandatory Appendix G	Installation of Strain Gages	391
Part 14	Condition Monitoring of Rotating Equipment in Nuclear Power Plants	392
1	Introduction	392
2	Definitions	392
3	References	392
4	Scope of Coverage	393
5	Condition-Monitoring Technologies	393
Nonmandatory Appendix A	Vibration Monitoring	398
Nonmandatory Appendix B	Lubricating Oil Analysis and Trending	416
Nonmandatory Appendix C	Thermography	423
Nonmandatory Appendix D	Motor Current Signature Analysis	429
Nonmandatory Appendix E	Motor Electrical Parameter Monitoring	431
Nonmandatory Appendix F	Process and Equipment Parameter Monitoring and General Observations	432

Part 17	Performance Testing of Instrument Air Systems in Light-Water Reactor Power Plants	433
Part 19	Preservice and Periodic Performance Testing of Pneumatically and Hydraulically Operated Valve Assemblies in Water-Cooled Reactor Nuclear Power Plants	434
1	Introduction	434
2	Definitions	434
3	Test Guidance	435
4	Test Methods	435
5	Analysis and Evaluation of Data	437
6	Corrective Action	437
Part 23	Inservice Monitoring of Reactor Internals Vibration in Pressurized Water Reactor Power Plants	438
1	Introduction	438
2	Definitions	438
3	References	440
4	Internals Vibration Excitation Sources, Responses, and Modes	441
5	Signal Database	441
6	Data Review	446
Nonmandatory Appendix A	Discussion of Spectral Functions	448
Nonmandatory Appendix B	Supporting Information on Component Vibrations	452
Nonmandatory Appendix C	Pump-Induced Vibrations	454
Nonmandatory Appendix D	Sampling Rate and Length of Data Record Requirement to Resolve a Spectral Peak	460
Figures		
ISTB-5223-1	Vibration Limits	16
ISTD-5431-1	The 37 Testing Sample Plan	39
E-1000-1	Flowchart for 10% Snubber Testing Plan (ISTD-5300)	90
E-1000-2	Flowchart for 37 Snubber Testing Plan (ISTD-5400)	91
L-2100-1	Acceptance Guidelines for CDF (Adapted From RG 1.174)	102
L-2100-2	Acceptance Guidelines for LERF (Adapted From RG 1.174)	103
1	Typical Components of a Vibration Monitoring System (VMS)	112
2	Deflection Measurement at the Intersection of Pipe and Elbow	118
3	Single Span Deflection Measurement	118
4	Cantilever Span Deflection Measurement	118
5	Cantilever Span/Elbow Span In-Plane Deflection Measurement	118
6	Cantilever Span/Elbow Guided Span In-Plane Deflection Measurement	118
7	Span/Elbow Span Out-of-Plane Deflection Measurement, Span Ratio < 0.5	118
8	Span/Elbow Span Out-of-Plane Deflection Measurement, Span Ratio > 0.5	119
9	Span/Elbow Span Out-of-Plane Configuration Coefficient Versus Ratio of Spans	119
10	Correction Factor C_1	120
B-1	Example of Time Span Selection to Exclude Spurious Data	129

B-2	Example of DC Offset Removal	129
B-3	Example of Band-Pass Filtering Between 5 Hz and 200 Hz	130
B-4	Example of Band-Stop Filtering for a 60 Hz Electrical Noise Peak	130
B-5	Example of Zero-to-Peak and Peak-to-Peak Values	131
B-6	Example of 50% Spectral Block Overlapping	133
F-1	Flowchart — Outline of Vibration Qualification of Piping Systems	141
H-1	Monitoring and Qualification of Piping Steady-State Vibration	145
I-1	Determination of L_E and W_T	149
1	Reactor Arrangement Showing Typical Ex-Core Detector Locations	151
A-1	Idealized Analysis for Core Barrel Motion	157
B-1	Representative Spectra	159
D-1	Narrowband rms	164
D-2	Example of Wideband rms Amplitude Versus Boron Concentration	165
E-1	Typical Ex-Core Neutron Noise Signatures From Six PWRs	168
E-2	Typical Baseline NPSD Range	169
E-3	Examples of Changes in the Neutron Noise Signature Over a Fuel Cycle	170
E-4	Example of Loss of Axial Restraint	171
1	System Heatup, Reconciliation, and Corrective Action	178
2	Typical Components of a TEMS	179
B-1	Simplified Schematic of Surge Line Stratification	185
1	Typical Broadband Sensor Response to Nearby Impact	190
2	Typical Broadband Sensor Response to More Distant Impact	190
3	Range of Loose Part Signal Amplitude and Predominant Frequency Content	191
4	Field Equipment	191
5	Direct Stud Mount	192
6	Clamped Mount	192
7	Recommended Sensor Array for PWR With U-Tube Steam Generator	194
8	Recommended Sensor Array for PWR With Once-Through Steam Generator	195
9	Recommended Sensor Array for BWR	196
10	Block Diagram for Charge Converter Calibration Tests	199
11	Cable Properties (Typical for Twisted-Shielded Pair Cable)	201
1	Boundary and Support Systems of Emergency Diesel Generator Systems	206
A-1	Post-Major Maintenance Test Data Form	218
B-1	Functional/Inservice Test Data Form	219
C-1	Typical Lube Oil System	221
C-2	Typical Jacket Water System	222
C-3	Intercooler Water System	223
C-4	Typical Air/Exhaust System	224
C-5	Typical Fuel Oil System	225
1	Intervals, Limits, and Parameter Trending (Typical)	231
2	Method Selection Chart	232
C-1	One Tube Row Air-to-Water Cross-Flow Heat Exchanger	260

C-2	Fin, Condensate Layer, and Interfaces	261
C-3	Schematic Representation of a Countercurrent Shell-and-Tube Heat Exchanger	267
C-4	A Small Element of a Countercurrent Shell-and-Tube Heat Exchanger	267
C-5	Cooling Water Inlet Temperature Versus Temperature Difference	273
IV-1	CCWS Typical Flow Diagram	325
VI-1	Typical Instrument Air System	332
B-1	Typical Branch Line System	341
B-2	Verifying Pump TDH Versus Flow: Correction of Measured Data for Instrument Accuracy	341
B-3	Verifying Pump TDH Versus Flow: Correction of Analysis Limits for Instrument Accuracy	342
B-4	Verifying Discharge Piping Overall Resistance: Correction of Measured Data for Instrument Accuracy	343
B-5	Verifying Discharge Piping Overall Resistance: Correction of Analysis Limits for Instrument Accuracy	343
B-6	Measured Subsystem Operating Point and Range of Operating Points Allowed by Analysis Limits	345
1	Tube Bundle Configuration With Tube Groupings Most Susceptible to Fluidelastic Instability Denoted by Cross-Hatching	358
A-1	Root Mean Square (rms) Acceleration Versus Flow Rate From Three Typical Tubes	367
A-2	Tube Response PSDs for Various Shell-Side Flow Rates (Ordinate Not to Scale)	368
E-1	Acoustic rms Spectrum for Nonimpacting Tube (No. 6-1) and Impacting Tube (No. 6-2)	375
E-2	Correlation of Signals From Microphone and In-Tube Accelerometer . .	376
E-3	Root Mean Square (rms) Tube Response Versus Flow Velocity	378
E-4	Response Versus Flow Velocity (Laboratory Test of 5 × 5 Tube Array)	378
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)	380
E-6	Displacement Time Histories From Accelerometer Pair in Heat Exchanger Tube Vibration Test	381
E-7	Acceleration Time Histories From Accelerometer Pair in Heat Exchanger Tube Vibration Test	381
E-8	Tube Vibration Patterns From X-Y Probe and Test of Industrial Size Shell-and-Tube Heat Exchanger	382
E-9	Frequency Response Curves for Tubes in Industrial Size Shell-and-Tube Heat Exchanger	383
E-10	Schematic of Test Setup	384
E-11	Root Mean Square (rms) Tube Displacements As Function of Flow Velocity (Diametral Gap of 1.02 mm)	385
E-12	Frequency Spectra of Tube Displacement at Location "A" (Diametral Gap of 1.27 mm)	386
E-13	Tube Displacement Time Histories at Location "A" (Diametral Gap of 0.51 mm)	387

A-1	An Example of a Vibration Trend Curve	413
1	Schematic of a Pressurized Water Reactor (PWR) Showing Typical Sensor Arrangement	439
2	Beam and Shell Mode Vibration of a PWR Core Support Barrel	442
3	Typical Components in a Signal Data Acquisition System	444
A-1	Different Spectral Functions	449
C-1	Reactor Coolant System Arrangement — Plan View	455
C-2	Data Set I, 180 deg Phase NCPD, A-D	456
C-3	Data Set II, 180 deg NCPD, A-D and B-C	457
C-4	180 deg Phase NCPD, X-Y	458
C-5	Lissajous Figure of Ex-Core Neutron Noise Data Showing Motion of Reactor Core in a Multi-Loop Plant	459
Tables		
ISTA-3170-1	Test Frequency and Time Between Tests	4
ISTB-3000-1	Inservice Test Parameters	8
ISTB-3400-1	Inservice Test Frequency	9
ISTB-3510-1	Required Instrument Accuracy	10
ISTB-5121-1	Centrifugal Pump Test Acceptance Criteria	12
ISTB-5221-1	Vertical Line Shaft Centrifugal Pump Test Acceptance Criteria	14
ISTB-5321-1	Positive Displacement Pump (Except Reciprocating) Test Acceptance Criteria	17
ISTB-5321-2	Reciprocating Positive Displacement Pump Test Acceptance Criteria	18
ISTC-3500-1	Inservice Test Requirements	22
ISTD-4252-1	Visual Examination Table	35
ISTE-5121-1	LSSC Pump Testing	48
ISTF-3000-1	Inservice Test Parameters	51
ISTF-3510-1	Required Instrument Accuracy	52
ISTF-5120-1	Centrifugal Pump Test Acceptance Criteria	55
ISTF-5220-1	Vertical Line Shaft and Centrifugal Pump Test Acceptance Criteria	56
ISTF-5320-1	Positive Displacement Pump (Except Reciprocating) Test Acceptance Criteria	57
ISTF-5320-2	Reciprocating Positive Displacement Pump Test Acceptance Criteria	57
I-4220-1	Seat Tightness Testing Methods for Pressure Relief Devices	68
II-4000-1	Maximum Intervals for Use When Applying Internal Extensions	70
J-2000-1	Check Valve Test Matrix	99
1	System Tolerances	113
2	Examples of Specifications of VMS Minimum Requirements; Measured Variable — Displacement	123
H-1	Recommended Actions for Piping Vibration Problem Resolution	146
1	Summary of Program Phases	153
C-1	Parameters to Be Documented During Data Acquisition	161
F-1	Ratio of the Amplitude of the Neutron Noise to Core Barrel Motion	172
1	An Example of Specification of TEMS Minimum Requirements	179
A-1	Typical Transducers	182
A-2	Typical Signal Conditioners	183

A-3	Typical Data Processing, Display, and Recording Equipment	183
1	Recommended PWR Accelerometer Locations	193
2	Recommended BWR Accelerometer Locations	195
1	Periodic Tests	210
1	Pumpset Mechanical Faults	284
2	Seal Faults	284
3	Electrical Motor Faults	285
4	Minimum Monitoring and Recording Intervals	289
5	Typical Thrust Position Alarm Setpoints for a Pump With Normal Upthrust	292
A-1	Operating Experience Information	337
C-1	Recorded Test Data	350
C-2	Calculated Pump Head	350
C-3	Sensitivity Coefficients for Pump TDH	350
C-4	Pump TDH Overall Accuracy Calculation	352
B-1	Upper Bound Estimate of the Random Turbulence Excitation Coefficient for Tube Bundle	371
1	Common Predictive Technology Applications	394
2	Typical Pump Mechanical Faults	395
3	Mechanical Seal Faults	395
4	Electrical Motor Faults	395
A-1	Comparison of Periodic and Continuous Monitoring and Relative Advantages	401
A-2	Noncontacting Displacement Probes — Probes Advantages Versus Disadvantages	403
A-3	Velocity Transducers — Transducer Advantages Versus Disadvantages	403
A-4	Accelerometers — Transducer Advantages and Disadvantages	404
A-5	Combination Probe Attached to Bearing Housing — Transducer Advantages and Disadvantages	404
A-6	Shaft Rider — Advantages and Disadvantages	405
A-7	Transducer Location Guidelines — Turbines	406
A-8	Transducer Location Guidelines — Equipment With Antifriction Bearings	407
A-9	Transducer Location Guidelines — Horizontal Pumps — Fluid Film Bearings	408
A-10	Transducer Location Guidelines — Motor-Driven Vertical Pumps — Fluid Film Bearings	409
A-11	Transducer Location Guidelines — Electric Motors	410
1	Sensor Types and Potential Applications in Reactor Noise Analysis	443
2	Relationships Between Sampling Rates and Analysis Results	444

FOREWORD

This document was developed and is maintained by The American Society of Mechanical Engineers (ASME) Committee on Operation and Maintenance (OM Committee) of Nuclear Power Plants. The OM Committee develops, revises, and maintains codes, standards, and guides applicable to the safe and reliable 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.

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Revisions and Errata. The committee processes revisions to this Code on a continuous basis to incorporate changes that appear necessary or desirable as demonstrated by the experience gained from the application of the Code. Approved revisions will be published in the next edition of the Code.

In addition, the committee may post errata on the committee web page. Errata become effective on the date posted. Users can register on the committee web page to receive e-mail notifications of posted errata.

This Code is always open for comment, and the committee welcomes proposals for revisions. Such proposals should be as specific as possible, citing the paragraph number(s), the proposed wording, and a detailed description of the reasons for the proposal, including any pertinent background information and supporting documentation.

Cases

(a) The most common applications for cases are

(1) to permit early implementation of a revision based on an urgent need

(2) to provide alternative requirements

(3) to allow users to gain experience with alternative or potential additional requirements prior to incorporation directly into the Code

(4) to permit the use of a new material or process

(b) Users are cautioned that not all jurisdictions or owners automatically accept cases. Cases are not to be considered as approving, recommending, certifying, or endorsing any proprietary or specific design, or as limiting in any way the freedom of manufacturers, constructors, or owners to choose any method of design or any form of construction that conforms to the Code.

(c) A proposed case shall be written as a question and reply in the same format as existing cases. The proposal shall also include the following information:

(1) a statement of need and background information

(2) the urgency of the case (e.g., the case concerns a project that is underway or imminent)

(3) the Code and the paragraph, figure, or table number(s)

(4) the edition(s) of the Code to which the proposed case applies

(d) A case is effective for use when the public review process has been completed and it is approved by the cognizant supervisory board. Approved cases are posted on the committee web page.

Interpretations. Upon request, the committee will issue an interpretation of any requirement of this Code. An interpretation can be issued only in response to a request submitted through the online Interpretation Submittal Form at <https://go.asme.org/InterpretationRequest>. Upon submitting the form, the inquirer will receive an automatic e-mail confirming receipt.

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PREFACE

GENERAL

In 2008, the ASME OM Committee directed that the two separately published OM Code and the OM Standards and Guides (OM-S/G) publications be combined into one document. This was done to ensure all of our standards and guides documents were readily available to users of the OM Code products. Some of the standards and guides were originally developed as part of the current operating nuclear power plants preoperational testing program conducted during the 1970s and 1980s. These standards and guides will be useful for power uprate projects and for new reactor design plant construction. Combining the OM Code and OM-S/G into one document makes the publication schedules for the Committee more efficient and easier to track.

ORGANIZATION

The consolidated code, standards, and guides for nuclear power plants, titled Operation and Maintenance of Nuclear Power Plants, are arranged into three distinct divisions. The titles of some of the sections were shortened to simplify the presentation purely for the user's ease of review and use. Reference to the individual published code, standard, or guide should be made for the specific title and the application requirements. Subsequent changes made to the Division contents will be detailed in future publications in separately listed summary of changes sections.

Division 1: OM Code: Section IST

Subsection ISTA	General Requirements
Subsection ISTB	Inservice Testing of Pumps — Pre-2000 Plants ¹
Subsection ISTC	Inservice Testing of Valves
Subsection ISTD	Preservice and Inservice Requirements for Dynamic Restraints (Snubbers)
Subsection ISTE	Risk-Informed Inservice Testing of Components
Subsection ISTF	Inservice Testing of Pumps — Post-2000 Plants ²

Mandatory Appendices

- I Inservice Testing of Pressure Relief Devices
- II Check Valve Condition-Monitoring Program
- III Preservice and Inservice Testing of Active Electric Motor-Operated Valve Assemblies
- IV Pneumatically and Hydraulically Operated Valves

Nonmandatory Appendices

- A Preparation of Test Plans
- B Dynamic Restraint Examination Checklist Items
- C Dynamic Restraint Design and Operating Information
- D Comparison of Sampling Plans for Inservice Testing of Dynamic Restraints
- E Flowcharts for 10% and 37 Snubber Testing Plans
- F Dynamic Restraints (Snubbers) Service Life Monitoring Methods
- G Application of Table ISTD-4252-1, Snubber Visual Examination

¹ Pre-2000 plant: a nuclear power plant that was issued its construction permit by the applicable regulatory authority prior to January 1, 2000.

² Post-2000 plant: a nuclear power plant that was issued (or will be issued) its construction permit, or combined license for construction and operation, by the applicable regulatory authority on or following January 1, 2000.

- H Test Parameters and Methods
- J Check Valve Testing Following Valve Reassembly
- K Sample List of Component Deterministic Considerations
- L Acceptance Guidelines
- M Design Guidance for Nuclear Power Plant Systems and Component Testing

Division 2: OM Standards

- Part 3 Vibration Testing of Piping Systems
- Part 5 Inservice Monitoring of Core Support Barrel Axial Preload in Pressurized Water Reactor Power Plants
- Part 7 Thermal Expansion Testing of Nuclear Power Plant Piping Systems
- Part 12 Loose Part Monitoring
- Part 16 Performance Testing and Monitoring of Standby Diesel Generator Systems
- Part 21 Inservice Performance Testing of Heat Exchangers
- Part 24 Reactor Coolant and Recirculation Pump Condition Monitoring
- Part 26 Determination of Reactor Coolant Temperature From Diverse Measurements
- Part 28 Standard for Performance Testing of Systems

Division 3: OM Guides

- Part 11 Vibration Testing and Assessment of Heat Exchangers
- Part 14 Condition Monitoring of Rotating Equipment in Nuclear Power Plants
- Part 19 Preservice and Periodic Performance Testing of Pneumatically and Hydraulically Operated Valve Assemblies
- Part 23 Inservice Monitoring of Reactor Internals Vibration in Pressurized Water Reactor Power Plants

ASME OM CASES AND APPLICABILITY INDEX FOR ASME OM CASES

Cases represent alternatives or additions to the OM Code. A case can be a method of handling a reply to an inquiry when study indicated that the Code wording needs clarification, or when the reply modifies the existing requirements of the Code or grants permission to use alternative methods.

Cases remain in effect for the applicable editions and addenda until they are annulled.

The index and cases are updated periodically and are available under the “O&M CASES” tab in the left-hand column at <http://go.asme.org/OMcommittee>.

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CROSS-REFERENCING IN ASME OM

ASME OM-2020 implemented stylistic changes to the labeling and cross-referencing of subparagraph breakdowns (i.e., nested lists). The following is a guide to the system of cross-referencing:

Hierarchy of Subparagraph Breakdowns

- First-level breakdowns are designated as (a), (b), (c), etc.
- Second-level breakdowns are designated as (1), (2), (3), etc.
- Third-level breakdowns are designated as (-a), (-b), (-c), etc.
- Fourth-level breakdowns are designated as (-1), (-2), (-3), etc.

Cross-References

The cross-references within a paragraph do not include the alphanumeric designator of that paragraph. The cross-references to a subparagraph breakdown follow the hierarchy of the designators under which the breakdown appears. The following examples illustrate the format:

- If ISXX-1000(a) is referenced in ISXX-1000(b), it is referenced as (a).
- If ISXX-1000(a)(1) is referenced in ISXX-1000(a)(2), it is referenced as (1).
- If ISXX-1000(a)(1) is referenced in ISXX-1000(b), it is referenced as (a)(1).
- If ISXX-1000(a)(1) is referenced in ISXX-2000, it is referenced as ISXX-1000(a)(1).

ASME OM-2022

SUMMARY OF CHANGES

Following approval by the ASME OM Committee and ASME, and after public review, ASME OM-2022 was approved by the American National Standards Institute on August 2, 2022.

Throughout ASME OM-2022, the following abbreviations have replaced spelled-out terms: AOV = air-operated valve; BPVC = Boiler and Pressure Vessel Code; BWR = boiling water reactor; CDF = core damage frequency; CFR = Code of Federal Regulations; HOV = hydraulic-operated valve; LER = large early release; LERF = large early release frequency; MOV = motor-operated valve; PM = preventative maintenance; PORV = power-operated relief valve; PWR = pressurized water reactor; and QA = quality assurance. ASME OM-2022 also includes the following changes identified by a margin note, (22).

<i>Page</i>	<i>Location</i>	<i>Change</i>
1	ISTA-1100	Subparagraph (a) revised
2	ISTA-2000	Definitions of <i>accident</i> and <i>safe shutdown</i> added
8	ISTB-3300	Subparagraph (h) added
9	ISTB-3420	Title and first two sentences revised
10	Table ISTB-3510-1	(1) Entry for "Vibration" revised (2) Notes (2) and (3) added
10	ISTB-3510	Subparagraph (e) revised
10	ISTB-3540	Subparagraph (e) added
11	ISTB-5121	Subparagraph (d) revised
12	Table ISTB-5121-1	Revised and Note (3) added
13	ISTB-5123	Subparagraph (d) revised
14	ISTB-5221	Subparagraph (d) revised
14	Table ISTB-5221-1	Revised and Note (3) added
15	ISTB-5223	Subparagraph (d) revised
15	ISTB-5321	Subparagraph (d) revised
17	Table ISTB-5321-1	Revised and Note (3) added
17	ISTB-5323	(1) Subparagraph (d) revised (2) In the second and third sentences of subpara. (e), table cross-references corrected
18	Table ISTB-5321-2	Revised and Note (1) added
20	ISTC-1200	In subpara. (d), "that" deleted by errata
21	ISTC-3100	Subparagraphs (d)(2) and (d)(3) revised
21	ISTC-3300	Third paragraph added
22	Table ISTC-3500-1	Revised in its entirety
22	ISTC-3510	First sentence revised
22	ISTC-3521	Revised in its entirety
23	ISTC-3570	Revised
24	ISTC-3630	In first sentence of subpara. (f), "valves specified" corrected by errata to "values specified"
25	ISTC-5100	Title revised

<i>Page</i>	<i>Location</i>	<i>Change</i>
25	ISTC-5110	Title revised
27	ISTC-5221	Subparagraph (b) and footnote 4 revised
28	ISTC-5230	Revised
33	ISTD-4200	Revised
33	ISTD-4234	Added
34	ISTD-4252	Subparagraphs (a) and (e) revised
35	Table ISTD-4252-1	Notes (1) through (6) revised and Note (7) added
34	ISTD-4253	Added
40	ISTD-6600	Added
40	ISTD-6700	Added
42	ISTE-2000	Definition of <i>defense in depth</i> revised
43	ISTE-3100	Revised
51	ISTF-3300	Subparagraph (h) added
52	Table ISTF-3510-1	Revised and Notes (2) and (3) added
52	ISTF-3420	Title and first two sentences revised
52	ISTF-3510	Subparagraph (e) revised in its entirety
53	ISTF-3540	Subparagraph (e) added
54	ISTF-5120	Subparagraph (c) revised
55	Table ISTF-5120-1	Revised and Note (3) added
54	ISTF-5220	Subparagraph (c) revised
55	ISTF-5320	Subparagraph (c) revised
56	Table ISTF-5220-1	(1) Reinstated (table inadvertently omitted from ASME OM-2020) (2) Revised and Note (3) added
57	Table ISTF-5320-1	Revised and Note (3) added
57	Table ISTF-5320-2	Revised and Note (1) added
68	Table I-4220-1	First column revised
69	II-1100	Added
69	II-4000	(1) Subparagraphs (a)(2), (b)(1)(-e), and (b)(2) revised (2) Subparagraph (b)(1)(-h) added (3) Subparagraph (b)(5) corrected by errata
73	III-3310	Subparagraph (b) revised and subparagraph (d) deleted
73	III-3620	Subparagraph (a) revised
74	III-3720	First sentence revised
75	III-6200	Last paragraph added
75	III-6300	Last paragraph added
76	III-9200	Revised
94	G-2000	Note revised
94	G-3100	Revised
94	G-3300	Revised
95	G-4400	Added
108	M-3540	Title revised
114	Division 2, Part 3, 3.1.2	Revised
121	Division 2, Part 3, 6	Revised
121	Division 2, Part 3, 6.1	Revised in its entirety

<i>Page</i>	<i>Location</i>	<i>Change</i>
124	Division 2, Part 3, Nonmandatory Appendix A	Revised in its entirety
128	Division 2, Part 3, Nonmandatory Appendix B	Revised in its entirety
134	Division 2, Part 3, Nonmandatory Appendix C	Revised in its entirety
287	Division 2, Part 24, 6.2.4	Revised
392	Division 3, Part 14	Revised in its entirety

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DIVISION 1

OM CODE: SECTION IST

Subsection ISTA

General Requirements

ISTA-1000 INTRODUCTION

(22) ISTA-1100 Scope

Section IST establishes the requirements for preservice and inservice testing and examination of certain components to assess their operational readiness in water-cooled reactor nuclear power plants. It identifies the components subject to test or examination, responsibilities, methods, intervals, parameters to be measured and evaluated, criteria for evaluating the results, corrective action, personnel qualification, and record keeping. These requirements apply to

(a) pumps and valves that are credited to perform a specific function in shutting down a reactor to the safe shutdown condition, in maintaining the safe shutdown condition, or in mitigating the consequences of an accident

(b) pressure relief devices that protect systems or portions of systems that perform one or more of the three functions identified in (a)

(c) dynamic restraints (snubbers) used in systems that perform one or more of the three functions identified in (a), or to ensure the integrity of the reactor coolant pressure boundary

ISTA-1200 Jurisdiction

The jurisdiction of Section IST covers individual components that have met all the requirements of the construction code commencing at the time when the construction code requirements have been met, irrespective of the physical location. When portions of systems or plants are completed at different times, the jurisdiction of this Section shall cover only those components on which all construction related to the components has been completed.

ISTA-1300 Application

ISTA-1310 Components Subject to Testing and Examination. Components identified in Section IST for testing or examination shall be included in the test plan (ISTA-3110). These components include nuclear power plant items such as pumps, valves, and dynamic restraints (snubbers).

ISTA-1320 Classifications. Optional construction of a component in a system boundary to a classification higher than the minimum class established in the component Design Specification (upgrading from either Class 2 to Class 1 or Class 3 to Class 2) shall not affect the overall system classification by which the applicable requirements of Section IST are determined.

ISTA-1400 Referenced Standards and Specifications

When standards and specifications are referenced in Section IST, the Owner shall validate that the specific revisions of the standards and specifications are acceptable for application to Section IST.

ISTA-1500 Owner's Responsibilities

The responsibilities of the Owner of the nuclear power plant shall include the following:

(a) determination of the appropriate Code Class for each component of the plant, identification of the system boundaries for each class of components subject to test or examination, and the components exempt from testing or examination requirements.

(b) design and arrangement of system components to include allowance for adequate access and clearances for conduct of the tests and examinations. Refer to [Division 1, Nonmandatory Appendix M](#) for guidance.

(c) preparation of plans and schedules.

(d) preparation of written test and examination instructions and procedures.

(e) qualification of personnel who perform and evaluate examinations and tests in accordance with the Owner's quality assurance (QA) program.

(f) performance of required tests and examinations.

(g) recording of required test and examination results that provide a basis for evaluation and facilitate comparison with the results of subsequent tests or examinations.

(h) evaluation of tests and examination results.

(i) maintenance of adequate test and examination records such as test and examination data and description of procedures used.

(j) retention of all test and examination records for the service lifetime of the component or system.

(k) documentation of a QA program in accordance with either of the following:

(1) Title 10, Code of Federal Regulations (CFR), Part 50

(2) ASME NQA-1, Parts II and III

ISTA-1600 Accessibility

Provisions for examination shall include access for the examination personnel and equipment necessary to conduct the test or examination.

(22) ISTA-2000 DEFINITIONS

accident(s): refer to postulated accident(s) or event(s) that are used to set plant design criteria and limits (including potential offsite exposures) which are evaluated in the plant's design basis accident analysis documents to demonstrate acceptability of the plant design in accordance with the licensing guidelines specified by the applicable regulatory authority, and to postulated accident(s) and event(s) required to be included in the IST program by regulatory commitments for the plant. Other accidents or events are addressed by separate requirements (such as fire protection requirements) that are imposed by regulatory authorities having jurisdiction at the plant site.

cold shutdown outage: applies to each nonrefueling outage period in which the cold shutdown mode, as defined by plant technical specifications, is entered.

equipment dynamic restraint (snubber): device that provides restraint to a component or system during the sudden application of forces, but allows essentially free motion during thermal movement.

examination: observing, visual monitoring, or measuring to determine conformance to Owner-specified requirements.

exercising: demonstration based on direct visual or indirect positive indications that the moving parts of a component function.

inservice test: test to assess the operational readiness of a system, structure, or component after first electrical generation by nuclear heat.

instrument loop: two or more instruments or components working together to provide a single output.

instrument loop accuracy: accuracy of an instrument loop based on the square root of the sum of the squares of the inaccuracies of each instrument or component in the loop when considered separately. Alternatively, the allowable inaccuracy of the instrument loop may be based on the output for a known input into the instrument loop.

maintenance: replacement of parts, adjustments, and similar actions that do not change the design (configuration and material) of an item.

modification: alteration in the design of a system, structure, or component.

monitoring: continuous or periodic observation or measurement to ascertain the performance or obtain characteristics of a system, structure, or component.

nonintrusive testing: testing performed on a component without disassembly or disturbing the boundary of the component.

obturator: valve closure member (disk, gate, plug, etc.).

operational readiness: the ability of a component to perform its specified functions.

overpressure protection: the means by which components are protected from overpressure by the use of pressure-relieving devices or other design provisions as required by the ASME Boiler and Pressure Vessel Code (ASME BPVC), Section III, or other applicable construction codes.

Owner: an organization owning or operating a facility where items are installed or used.

performance testing: a test to determine whether a system or component meets specified acceptance criteria.

plant operation: the conditions of startup, operation at power, hot standby, and reactor cooldown, as defined by plant technical specifications.

post-2000 plant: a nuclear power plant that was issued (or will be issued) its construction permit, or combined license for construction and operation, by the applicable regulatory authority on or following January 1, 2000.

pre-2000 plant: a nuclear power plant that was issued its construction permit, or combined license for construction and operation, by the applicable regulatory authority prior to January 1, 2000.

preservice test: test performed 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.

preservice test period: the period of time following completion of construction activities related to the component and before first electrical generation by nuclear heat, in which component and system testing takes place, or

in an operating plant prior to the component being initially placed in service.

pump: a mechanical device used to move fluid.

qualitative testing: testing performed to establish parameters without determining the specific measure of the parameter.

quantitative testing: testing performed to establish the specific measure or limit of a parameter, such as that required to establish that a parameter is within a specified range.

reference point: a point of operation at which reference values are established and inservice test parameters are measured for comparison with applicable acceptance criteria.

reference values: one or more values of parameters as measured or determined when the equipment is known to be operating acceptably.

refueling outage: applies to the normally scheduled once-per-cycle outage period in which the refueling mode, as defined by plant technical specifications, is entered.

repair: the process of restoring a degraded item to its original design requirements.

routine servicing: performance of planned, preventive maintenance (PM).

safe shutdown: a unit shutdown with

(a) the reactivity of the reactor kept to a margin below criticality, consistent with the plant's licensing documentation;

(b) the core decay heat removed at a controlled rate sufficient to prevent core or reactor coolant system thermal design limits from being exceeded;

(c) radioactive material releases controlled to keep doses within prescribed limits; and

(d) operation within design limits of safe shutdown components necessary to maintain these conditions

For a description of the plant's safe shutdown condition, refer to the plant's licensing documentation.

skid-mounted pumps and valves: pumps and valves integral to or that support operation of major components, even though these pumps and valves may not be located directly on the skid. In general, these pumps and valves are supplied by the manufacturer of the major component. Examples include

(a) diesel fuel oil pumps and valves

(b) steam admission and trip throttle valves for high-pressure coolant injection turbine-driven pumps

(c) steam admission and trip throttle valves for auxiliary feedwater turbine-driven pumps

(d) solenoid-operated valves provided to control an air-operated valve

system resistance: hydraulic resistance to flow.

trending: a comparison of current data to previous data obtained under similar conditions for the same equipment.

valves, active: valves that are required to change obturator position to accomplish a specific function in shutting down a reactor to the safe shutdown condition, maintaining the safe shutdown condition, or mitigating the consequences of an accident.

valves, passive: valves that maintain obturator position and are not required to change obturator position to accomplish the required function(s) in shutting down a reactor to the safe shutdown condition, maintaining the safe shutdown condition, or mitigating the consequences of an accident.

ISTA-3000 GENERAL REQUIREMENTS

ISTA-3100 Test and Examination Program

ISTA-3110 Test and Examination Plans. Test plans shall be prepared for the preservice test period, initial inservice, and subsequent inservice test intervals.¹

Each inservice test plan shall include the following:

(a) the edition and addenda of this Section that apply to the required tests and examinations

(b) the classification of the components and the boundaries of system classification

(c) identification of the components subject to tests and examination

(d) the Code requirements for each component and the test or examination to be performed

(e) the Code requirements for each component that are not being satisfied by the tests or examinations; and justification for substitute tests or examinations

(f) Code Cases proposed for use and the extent of their application

(g) test or examination frequency or a schedule for performance of tests and examinations, as applicable

ISTA-3120 Inservice Examination and Test Interval

(a) The examination and test interval shall be determined by calendar years following placement of the unit into commercial service.

(b) The examination and test intervals shall comply with the following, except as modified by (c) and (d):

(1) *Initial Examination and Test Interval*: 10 yr following initial start of unit commercial service

(2) *Successive Examination and Test Intervals*: 10 yr following the previous test interval

(c) Each of the inservice examination and test intervals may be extended or decreased by as much as 1 yr. Adjustments shall not cause successive intervals to be altered by more than 1 yr from the original pattern of intervals.

¹Guidance for the preparation of test plans is in [Division 1, Nonmandatory Appendix A](#).

Table ISTA-3170-1
Test Frequency and Time Between Tests

Frequency	Specified Time Between Tests
Quarterly (or every 3 months)	92 days
Semiannually (or every 6 months)	184 days
Annually (or every year)	366 days
x years	x calendar years where x is a whole number of years ≥ 2

(d) In addition to (c), for units that are out of service continuously for 6 months or more, the examination and test interval during which the outage occurred may be extended for a period equivalent to the outage and the original pattern of intervals extended accordingly for successive intervals.

(e) The inservice examination and test intervals for component replacements, additions, and alterations that may be required during the service lifetime of the unit shall coincide with the remaining intervals, as determined by the calendar years of unit service at the time of replacement, addition, or alteration.

ISTA-3130 Application of Code Cases

(a) Code Cases to be used during a preservice or inservice test or examination shall be identified in the test plan.

(b) Code Cases shall be applicable to the edition and addenda specified in the test plan.

(c) Code Cases shall be in effect at the time the test plan is filed, except as provided in (d).

(d) Code Cases issued subsequent to filing the test plan may be proposed for use in amendments to the test plan.

ISTA-3140 Application of Revised Code Cases. Superseded Code Cases approved for use in accordance with [ISTA-3130](#) may continue to be used.

ISTA-3150 Application of Annulled Code Cases. Code Cases approved for use in accordance with [ISTA-3130](#) or [ISTA-3140](#) may be used after annulment for the duration of that test plan.

ISTA-3160 Test and Examination Procedures. Tests and examinations shall be performed in accordance with written procedures. The procedures shall contain the Owner-specified reference values and acceptance criteria.

ISTA-3170 Inservice Examination and Test Frequency Grace. Section IST specifies component test frequencies based on either elapsed time periods (e.g., quarterly, 2 yr, etc.) or the occurrence of plant conditions or events (e.g., cold shutdown, refueling outage, upon detection of a sample failure, following maintenance, etc.).

(a) Components whose test frequencies are based on elapsed time periods shall be tested at the frequencies specified in Section IST with a specified time period

between tests as shown in [Table ISTA-3170-1](#). The specified time period between tests may be reduced or extended as follows:

(1) For periods specified as fewer than 2 yr, the period may be extended by up to 25% for any given test.

(2) For periods specified as greater than or equal to 2 yr, the period may be extended by up to 6 months for any given test.

(3) All periods specified may be reduced at the discretion of the Owner (i.e., there is no minimum period requirement).

Period extension is to facilitate test scheduling and considers plant operating conditions that may not be suitable for performance of the required testing (e.g., performance of the test would cause an unacceptable increase in the plant risk profile due to transient conditions or other ongoing surveillance, test, or maintenance activities). Period extensions are not intended to be used repeatedly merely as an operational convenience to extend test intervals beyond those specified.

Period extensions may also be applied to accelerated test frequencies (e.g., pumps in alert range) and other fewer than 2-yr test frequencies not specified in [Table ISTA-3170-1](#).

Period extensions may not be applied to the test frequency requirements specified in [Subsection ISTD](#), as [Subsection ISTD](#) contains its own rules for period extensions.

(b) Components whose test frequencies are based on the occurrence of plant conditions or events may not have their period between tests extended except as allowed by Section IST.

ISTA-3200 Administrative Requirements

(a) The selection of components included in the test plan is subject to review by the regulatory authorities having jurisdiction at the plant site.

(b) Application of the requirements of this Section shall be governed by group classification criteria of the regulatory authority having jurisdiction at the plant site.

(c) The use of any Code Case is subject to acceptance by the regulatory authorities having jurisdiction at the plant site.

(d) Revisions to a previously approved Code Case may be substituted for that Code Case with the acceptance of the regulatory authorities having jurisdiction at the plant site.

(e) The Code edition and addenda for the preservice test period, initial inservice test interval, and successive inservice test intervals shall be as required by the regulatory authority having jurisdiction at the plant site.

ISTA-3300 Corrective Actions

Corrective actions requiring repair/replacement activities shall be performed in accordance with ASME BPVC, Section XI, as applicable. Other corrective actions shall be performed in accordance with the Owner's QA program.

ISTA-4000 INSTRUMENTATION AND TEST EQUIPMENT**ISTA-4100 Range and Accuracy**

Instrumentation and test equipment used in performing the examination and testing program shall have the range and accuracy necessary to demonstrate conformance to specific examination or test requirements.

ISTA-4200 Calibration

All instruments and test equipment used in performing the examination and testing program shall be calibrated and controlled in accordance with the Owner's administrative procedures or a QA program approved by the Owner.

ISTA-5000 SPECIFIC TEST REQUIREMENTS

The specific test requirements for preservice and inservice tests and examinations for pumps, valves, and dynamic restraints (snubbers) are described in the applicable subsections of this Code.

ISTA-6000 MONITORING, ANALYSIS, AND EVALUATION

Monitoring, analysis, and evaluation requirements for preservice and inservice tests and examinations for pumps, valves, and dynamic restraints (snubbers) are described in the applicable subsections of this Code.

ISTA-7000 TO BE PROVIDED AT A LATER DATE**ISTA-8000 TO BE PROVIDED AT A LATER DATE****ISTA-9000 RECORDS AND REPORTS****ISTA-9100 Scope**

The requirements for retention of records apply to those records generated in the course of performing preservice and inservice tests and examinations required by Section IST.

ISTA-9200 Requirements**ISTA-9210 Owner's Responsibility**

(a) The Owner shall prepare plans for preservice and inservice tests and examinations to meet the requirements of Section IST.

(b) The Owner shall prepare and retain records of the preservice and inservice tests and examinations.

ISTA-9220 Preparation

(a) Test and examination records shall be prepared in accordance with the requirements of the Subsection applicable to the test and examination requirements.

(b) Plans shall have a cover sheet providing the following information:

- (1) date of document completion
- (2) name and address of Owner
- (3) name and address of plant
- (4) name and number designation of the unit
- (5) commercial service date for the unit

ISTA-9230 Inservice Test and Examination Results.

The results of tests and examinations shall be documented and shall include the following, as a minimum:

- (a) component identification
- (b) date of test or examination
- (c) reason for test or examination (e.g., postmaintenance, routine inservice test or examination, establishing reference values, etc.)
- (d) test or examination procedure used
- (e) identification of test equipment used
- (f) calibration records, or traceability to calibration records
- (g) values of measured parameters
- (h) comparison with allowable ranges of test and examination values, and analysis of deviations
- (i) requirement for corrective action
- (j) documentation of the person(s) responsible for conducting and analyzing the test or examination per the Owner's QA program

ISTA-9240 Record of Corrective Actions. The Owner shall maintain records of corrective action that shall include a summary of the corrective actions made, the subsequent inservice test or examination, confirmation of operational adequacy, and the printed (or typed) name and signature of the person(s) responsible for the corrective action and verification of results.

ISTA-9300 Retention

ISTA-9310 Maintenance of Records. The Owner shall retain records identified in [ISTA-9330](#) as a minimum. The records shall be filed and maintained. The Owner shall provide suitable protection from deterioration and damage for all records, in accordance with the Owner's QA program for the service lifetime of the component or system. Storage shall be either at the plant site or at another location that will meet the access and QA program requirements.

ISTA-9320 Reproduction. Records shall be either the original or a legible copy.

ISTA-9330 Test and Examination Records. The Owner shall be responsible for designating the records to be maintained. Such records shall include the following as a minimum:

- (a) an index to record file
- (b) test plans (see [ISTA-3110](#))
- (c) test and examination results
- (d) records of corrective actions

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Subsection ISTB

Inservice Testing of Pumps in Water-Cooled Reactor Nuclear Power Plants — Pre-2000 Plants¹

ISTB-1000 INTRODUCTION

ISTB-1100 Applicability

The requirements of this Subsection apply to certain centrifugal and positive displacement pumps that have an emergency power source.

ISTB-1200 Exclusions

The following are excluded from this Subsection:

- (a) drivers, except where the pump and driver form an integral unit and the pump bearings are in the driver
- (b) pumps that are supplied with emergency power solely for operating convenience
- (c) skid-mounted pumps that are tested as part of the major component and are justified by the Owner to be adequately tested

ISTB-1300 Pump Categories

All pumps within the scope of [ISTA-1100](#) and [ISTB-1100](#) shall be categorized as either a Group A or a Group B pump.

ISTB-1400 Owner's Responsibility

In addition to the requirements of [ISTA-1500](#), the Owner's responsibility includes

- (a) providing in both the pumps and plant design all necessary valving, instrumentation, test loops, required fluid inventory, or other provisions that are required to fully comply with the requirements of this Subsection.
- (b) identifying each pump to be tested in accordance with the rules of this Subsection, categorizing the pump as either a Group A or a Group B pump, and listing the pumps in the plant records (see [ISTB-9000](#)). A pump that meets both Group A and Group B pump definitions shall be categorized as a Group A pump.
- (c) establishing a comprehensive pump test flow rate for each pump.
- (d) identifying those pumps with specific design basis accident flow rates in the Owner's credited safety analysis for inclusion in a pump periodic verification test program.

ISTB-2000 SUPPLEMENTAL DEFINITIONS

The following are provided to ensure a uniform understanding of selected terms used in this Subsection.

baseline test: a test performed when a pump is new, or overhauled, to obtain thorough information for use in the evaluation of degradation in pump performance.

comprehensive pump test flow rate: the flow rate established by the Owner that is effective for detecting mechanical and hydraulic degradation during subsequent testing. The best efficiency point, system flow rates, and any other plant-specific flow rates shall be considered.

Group A pumps: pumps that are operated continuously or routinely during normal operation, cold shutdown, or refueling operations.

Group B pumps: pumps in standby systems that are not operated routinely except for testing.

pump periodic verification test: a test that verifies a pump can meet the required (differential or discharge, as applicable) pressure at its highest design basis accident flow-rate.²

vertical line shaft pump: a vertically suspended pump where the pump driver and pump element are connected by a line shaft within an enclosed column.

ISTB-3000 GENERAL TESTING REQUIREMENTS

The hydraulic and mechanical condition of a pump relative to a previous condition can be determined by attempting to duplicate by test a set of reference values. Deviations detected are symptoms of changes and, depending upon the degree of deviation, indicate need for further tests or corrective action.

The parameters to be measured during preservice and inservice testing are specified in [Table ISTB-3000-1](#).

ISTB-3100 Preservice Testing

During the preservice test period, or before implementing inservice testing, a baseline test shall be performed and an initial set of reference values

¹ *Pre-2000 plant*: a nuclear power plant that was issued its construction permit by the applicable regulatory authority prior to January 1, 2000.

² A pump may have several design basis accident operating points due to different system configurations or single versus parallel pump operation.

Table ISTB-3000-1
Inservice Test Parameters

Quantity	Baseline Test	Group A Test	Group B Test	Comprehensive Test	Pump Periodic Verification Test [Note (1)]	Remarks
Speed, N	X	X	X	X	X	If variable speed
Differential pressure, ΔP	X	X	X [Note (2)]	X	X	Centrifugal pumps, including vertical line shaft pumps
Discharge pressure, P	X	X	...	X	X	Positive displacement pumps
Flow rate, Q	X	X	X [Note (2)]	X	X	...
Vibration	X	X	...	X	...	Measure either V_d or V_v
Displacement, V_d	...	...	...	...	...	Peak-to-peak
Velocity, V_v	...	...	...	...	...	Peak

NOTES:

(1) Only required for those pumps identified in [ISTB-1400\(d\)](#).

(2) For positive displacement pumps, flow rate shall be measured or determined; for all other pumps, differential pressure or flow rate shall be measured or determined.

established, in accordance with [ISTB-3300](#), for each pump required to be tested by this Subsection. Except as specified in [ISTB-3310](#), only one baseline test is required during the preservice test period for each pump. The baseline test shall be performed under conditions as near as practicable to those expected during subsequent inservice testing, in accordance with the requirements of the following:

- (a) centrifugal pump tests (except vertical line shaft centrifugal pumps) in accordance with [ISTB-5110](#)
- (b) vertical line shaft centrifugal pump tests in accordance with [ISTB-5210](#)
- (c) positive displacement pump tests in accordance with [ISTB-5310](#)

ISTB-3200 Inservice Testing

Inservice testing of a pump in accordance with this Subsection shall commence when the pump is required to be operable (see [ISTB-1100](#)). Inservice testing shall be performed in accordance with the requirements of the following paragraphs:

- (a) centrifugal pump tests (except vertical line shaft centrifugal pumps) in accordance with [ISTB-5120](#)
- (b) vertical line shaft centrifugal pump tests in accordance with [ISTB-5220](#)
- (c) positive displacement pump (except reciprocating) tests in accordance with [ISTB-5320](#)
- (d) reciprocating positive displacement pump tests in accordance with [ISTB-5320](#)

(22) ISTB-3300 Reference Values

Reference values shall be obtained as follows:

- (a) Initial reference values shall be determined from the results of testing meeting the requirements of [ISTB-3100](#), Preservice Testing, or from the results of the first inservice test.

(b) New or additional reference values shall be established as required by [ISTB-3310](#), [ISTB-3320](#), or [ISTB-6200\(c\)](#).

(c) Reference values shall be established only when the pump is known to be operating acceptably.

(d) Reference values shall be established at a point(s) of operation (reference point) readily duplicated during subsequent tests.

(e) Reference values shall be established in a region(s) of relatively stable pump flow.

(1) Reference values shall be established at the comprehensive pump test flow rate for the comprehensive test.

(2) Reference values shall be established at the comprehensive pump test flow rate for the Group A and Group B tests, if practicable. If not practicable, the reference point flow rate shall be established at the highest practical flow rate.

(f) All subsequent test results shall be compared to these initial reference values or to new reference values established in accordance with [ISTB-3310](#), [ISTB-3320](#), or [ISTB-6200\(c\)](#).

(g) Related conditions that can significantly influence the measurement or determination of the reference value shall be analyzed in accordance with [ISTB-6400](#).

(h) For smooth running pump measured vibration reference values less than 0.050 ips, the owner may use 0.050 ips as the minimum reference value for one or more of the vibration points. In such cases, the minimum reference value of 0.050 ips shall be used to define acceptable pump performance in accordance with [ISTB-5000](#).

ISTB-3310 Effect of Pump Replacement, Repair, and Maintenance on Reference Values

ISTB-3311 Replacement and Major Maintenance. Following replacement, major maintenance, or routine servicing (e.g., impeller replacement), such that the

existing baseline test data and reference values do not represent the installed pump, the following shall be performed before declaring the pump operable:

(a) A baseline test shall be performed in accordance with [ISTB-5110](#), [ISTB-5210](#), or [ISTB-5310](#), as applicable.

(b) A new set of reference values shall be established in accordance with [ISTB-3300](#) from the results of the baseline test.

(c) Verification that the new reference values represent acceptable pump operation shall be placed in the record of tests (see [ISTB-9000](#)).

(d) Determine whether the pump periodic verification test is required.

ISTB-3312 Routine Maintenance and Repair. When a reference value or set of reference values may have been affected by repair or routine maintenance, other than that covered under [ISTB-3311](#), the following shall be performed before declaring the pump operable:

(a) A group A or comprehensive test shall be performed and

(1) the previous reference values reconfirmed, or

(2) a new reference value, or set of reference values, shall be determined in accordance with [ISTB-3300](#). If new reference values are determined, deviations from the previous and new reference values shall be evaluated, and verification that the new values represent acceptable pump operation shall be placed in the record of tests (see [ISTB-9000](#)).

(b) Determine whether the pump periodic verification test is required.

ISTB-3313 Baseline Test Deferral. When the testing required by [ISTB-3311](#) is impracticable due to plant operating conditions, the testing may be deferred, providing the following requirements are met:

(a) A group A or comprehensive test shall be performed.

(b) A new reference value, or set of reference values, shall be determined in accordance with [ISTB-3300](#), or the previous value reconfirmed, prior to declaring the pump operable.

(c) The required test and other actions are performed in accordance with [ISTB-3311](#), the next time the plant enters a condition where the test can be performed, and no later than the resumption of electrical generation by nuclear energy at the conclusion of the next refueling outage.

(d) The current baseline test pump curve shall not be used for activities under [ISTB-3320\(a\)](#).

ISTB-3320 Establishment of Additional Set of Reference Values. If it is necessary or desirable, for some reason other than stated in [ISTB-3310](#), to establish an additional set of reference values, a Group A or comprehensive test shall be run at the conditions of an existing set of reference values and the results analyzed. If operation is

acceptable per [ISTB-6200](#), an additional set of reference values may be established as follows:

(a) For centrifugal and vertical line shaft pumps, the additional set of reference values shall be determined from the pump curve established in [ISTB-5110](#) or [ISTB-5210](#), as applicable. Vibration acceptance criteria shall be established by a Group A or comprehensive test at the new reference point. If vibration data were taken at all points used in determining the pump curve, an interpolation of the new vibration reference value is acceptable.

(b) For positive displacement pumps, the additional set of reference values shall be established per [ISTB-5310](#).

A test shall be run to verify the new reference values before their implementation. Whenever an additional set of reference values is established, the reasons for so doing shall be justified and documented in the record of tests (see [ISTB-9000](#)). The requirements of [ISTB-3300](#) apply.

ISTB-3400 Frequency of Inservice Tests

An inservice test shall be run on each pump as specified in [Table ISTB-3400-1](#). For those pumps identified in [ISTB-1400\(d\)](#), a pump periodic verification test shall be performed biennially in accordance with this Subsection. The Owner is not required to perform a pump periodic verification test if the design basis accident flow rate in the Owner's safety analysis is less than or equal to the comprehensive pump test flow rate or Group A test flow rate.

ISTB-3410 Pumps in Regular Use. Group A pumps that are operated more frequently than every 3 months need not be run or stopped for a special test, provided the plant records show the pump was operated at least once every 3 months at the reference conditions, and the quantities specified were determined, recorded, and analyzed per [ISTB-6000](#).

ISTB-3420 Pumps Out of Service. For a pump declared inoperable or not required to be operable, the test schedule need not be followed. Within 3 months before the pump is placed in an operable status, the pump shall

**Table ISTB-3400-1
Inservice Test Frequency**

Pump Group	Group A Test	Group B Test	Comprehensive Test	Pump Periodic Verification Test [Note (1)]
Group A	Quarterly	N/A	Biennially	Biennially
Group B	N/A	Quarterly	Biennially	Biennially

GENERAL NOTE: N/A = Not applicable.

NOTE: (1) Only required for those pumps identified in [ISTB-1400\(d\)](#).

(22)

Table ISTB-3510-1
Required Instrument Accuracy

Quantity	Group A and Group B Test, %	Comprehensive and Baseline Tests, %	Pump Periodic Verification Test, %
Pressure	±2	±½	[Note (1)]
Flow rate	±2	±2	[Note (1)]
Speed	±2	±2	[Note (1)]
Vibration			
>4 Hz to 1,000 Hz [Note (2)]	±5	±5	N/A
1 Hz to 4 Hz [Note (3)]	±15	±15	N/A
Differential pressure	±2	±½	[Note (1)]

NOTES:

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

be tested and the test schedule followed in accordance with the requirements of this Subsection. Pumps that can only be tested during plant operation shall be tested within 1 week following plant startup.

ISTB-3430 Pumps Lacking Required Fluid Inventory.

Group B pumps lacking required fluid inventory (e.g., pumps in dry sumps) shall receive a comprehensive test at least once every 2 yr except as provided in [ISTB-3420](#). The required fluid inventory shall be provided during this test. A Group B test is not required.

ISTB-3500 Data Collection

(22) ISTB-3510 General

(a) *Accuracy.* Instrument accuracy shall be within the limits of [Table ISTB-3510-1](#). If a parameter is determined by analytical methods instead of measurement, then the determination shall meet the parameter accuracy requirement of [Table ISTB-3510-1](#) (e.g., flow rate determination shall be accurate to within ±2% of actual). For individual analog instruments, the required accuracy is percent of full-scale. For digital instruments, the required accuracy is over the calibrated range. For a combination of instruments, the required accuracy is loop accuracy.

(b) Range

(1) The full-scale range of each analog instrument shall be not greater than 3 times the reference value.

(2) Digital instruments shall be selected such that the reference value does not exceed 90% of the calibrated range of the instrument.

(3) Vibration instruments are excluded from the range requirements of (1) and (2).

(c) *Instrument Location.* The sensor location shall be established by the Owner, documented in the plant records (see [ISTB-9000](#)), and shall be appropriate for the parameter being measured. The same location shall be used for subsequent tests. Instruments that are position sensitive shall be permanently mounted or provision shall be made to duplicate their position during each test.

(d) *Fluctuations.* Symmetrical damping devices or averaging techniques may be used to reduce instrument fluctuations. Hydraulic instruments may be damped by using gage snubbers or by throttling small valves in instrument lines.

(e) Frequency Response Range

(1) For pumps operating at or above 600 rpm, the frequency response range of the vibration-measuring transducers and their readout system shall be from one-third minimum pump shaft rotational speed to at least 1,000 Hz.

(2) For slow speed pumps operating below 600 rpm, the frequency response range of the vibration-measuring transducers and their readout system shall be no lower than 1 Hz to at least 1,000 Hz.

ISTB-3520 Pressure

(a) *Gage Lines.* If the presence or absence of liquid in a gage line could produce a difference of more than 0.25% in the indicated value of the measured pressure, means shall be provided to ensure or determine the presence or absence of liquid as required for the static correction used.

(b) *Differential Pressure.* When determining differential pressure across a pump, a differential pressure gage or a differential pressure transmitter that provides direct measurement of the pressure difference or the difference between the pressure at a point in the inlet and the pressure at a point in the discharge pipe shall be used.

ISTB-3530 Rotational Speed. Rotational speed measurements of variable speed pumps shall be taken by a method that meets the requirements of [ISTB-3510](#).

ISTB-3540 Vibration

(22)

(a) On centrifugal pumps, except vertical line shaft pumps, measurements shall be taken in a plane approximately perpendicular to the rotating shaft in two approximately orthogonal directions on each accessible pump-bearing housing. Measurement shall also be taken in the axial direction on each accessible pump thrust bearing housing.

(b) On vertical line shaft pumps, measurements shall be taken on the upper motor-bearing housing in three approximately orthogonal directions, one of which is the axial direction.

(c) On reciprocating pumps, the location shall be on the bearing housing of the crankshaft, approximately perpendicular to both the crankshaft and the line of plunger travel.

(d) If a portable vibration indicator is used, the measurement points shall be clearly identified on the pump to permit subsequent duplication in both location and plane.

(e) Pumps that will use the minimum reference value for one or more vibration points shall use trending analysis of measured vibration amplitudes in the frequency domain to assess performance at these locations. The Owner shall document the conclusion of the performance analysis prior to the subsequent test with a conclusion of acceptable, degrading but acceptable, or unacceptable. Corrective action shall be initiated when an unacceptable trend in performance is identified.

If a supplemental monitoring activity identifies a parameter outside the normal operating range or identifies a trend toward an unacceptable degraded state, action shall be taken to

(1) identify and document the condition in the corrective action program established in accordance with the Owner's QA program

(2) increase monitoring to establish the rate of change of the monitored parameter

(3) review component-specific information to identify the degradation cause

(4) develop a plan to remove the pump from service to perform maintenance prior to significant performance degradation

(5) address potential generic concerns applicable to other pumps based on the results of the analysis of the specific pump performance

ISTB-3550 Flow Rate. When measuring flow rate, a rate or quantity meter shall be installed in the pump test circuit. If a meter does not indicate the flow rate directly, the record shall include the method used to reduce the data. Internal recirculated flow is not required to be measured. External recirculated flow is not required to be measured if it is not practical to isolate, has a fixed resistance, and has been evaluated by the Owner to not have a substantial effect on the results of the test.

ISTB-4000 TO BE PROVIDED AT A LATER DATE

ISTB-5000 SPECIFIC TESTING REQUIREMENTS

This Subsection defines requirements for baseline, Group A, Group B, and comprehensive tests.

(a) When a Group B test is required, a Group A, comprehensive, or baseline test may be substituted.

(b) When a Group A test is required, a comprehensive or baseline test may be substituted.

(c) When a comprehensive test is required, a baseline test may be substituted.

ISTB-5100 Centrifugal Pumps (Except Vertical Line Shaft Centrifugal Pumps)

(a) Duration of Tests

(1) For the Group A test and the comprehensive test, after pump conditions are as stable as the system permits, each pump shall be run at least 2 min. At the end of this time at least one measurement or determination of each of the quantities required by [Table ISTB-3000-1](#) shall be made and recorded.

(2) For the Group B test, after pump conditions are stable, at least one measurement or determination of the quantity required by [Table ISTB-3000-1](#) shall be made and recorded.

(b) Bypass Loops

(1) A bypass test loop may be used for a Group A test or comprehensive test, provided the flow rate through the loop meets the requirements as specified in [ISTB-3300](#).

(2) A bypass test loop may be used for Group B tests if it is designed to meet the pump manufacturer's operating specifications (e.g., flow rate, time limitations) for minimum flow operation.

ISTB-5110 Baseline Testing. The parameters to be measured are specified in [Table ISTB-3000-1](#).

(a) In systems where resistance can be varied, flow rate and differential pressure shall be measured at a minimum of five points. If practicable, these points shall be from pump minimum flow to at least the comprehensive pump test flow rate, or, if a pump periodic verification test is required per [ISTB-3400](#), the pump design basis accident flow rate in the credited Owner's safety analysis, whichever is higher. A pump curve shall be established based on the measured points. At least one point shall be designated as the reference point(s). Data taken at the reference point will be used to compare the results of inservice tests. A pump curve need not be established for pumps in systems where resistance cannot be varied.

(b) Vibration measurements are only required to be taken at the reference point(s).

ISTB-5120 Inservice Testing

ISTB-5121 Group A Test Procedure. Group A tests (22) shall be conducted with the pump operating as close as practical to a specified reference point and within the variances from the reference point as described in this paragraph. The test parameters shown in [Table ISTB-3000-1](#) shall be determined and recorded as required by this paragraph. The test shall be conducted as follows:

Table ISTB-5121-1
Centrifugal Pump Test Acceptance Criteria

(22)

Test Type	Pump Speed	Test Parameter	Acceptable Range	Alert Range	Required Action Range	
					Low	High
Group A test [Notes (1), (2)]	N/A	Q	$0.90Q_r$ to $1.10Q_r$	None	$<0.90Q_r$	$>1.10Q_r$
	N/A	ΔP	$0.90\Delta P_r$ to $1.10\Delta P_r$	None	$<0.90\Delta P_r$	$>1.10\Delta P_r$
	<600 rpm	V_v [Note (3)]	≤ 0.125 in./sec (≤ 0.3 cm/s)	>0.125 in./sec to 0.300 in./sec (>0.3 cm/s to 0.7 cm/s)	None	>0.300 in./sec (>0.7 cm/s)
		V_d or V_v	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$ or >10.5 mils to 22 mils (>266.7 μm to 558.8 μm)	None	$>6V_r$ or >22 mils (>558.8 μm)
	≥ 600 rpm	V_v [Note (3)]	≤ 0.125 in./sec (≤ 0.3 cm/s)	>0.125 in./sec to 0.300 in./sec (>0.3 cm/s to 0.7 cm/s)	None	>0.300 in./sec (>0.7 cm/s)
		V_d or V_v	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$ or >0.325 in./sec to 0.7 in./sec (>0.8 cm/s to 1.7 cm/s)	None	$>6V_r$ or >0.7 in./sec (>1.7 cm/s)
Group B test	N/A	Q , or	$0.90Q_r$ to $1.10Q_r$	None	$<0.90Q_r$	$>1.10Q_r$
	N/A	ΔP	$0.90\Delta P_r$ to $1.10\Delta P_r$	None	$<0.90\Delta P_r$	$>1.10\Delta P_r$
Comprehensive test [Notes (1), (2)]	N/A	Q	$0.94Q_r$ to $1.06Q_r$	$0.90Q_r$ to $<0.94Q_r$	$<0.90Q_r$	$>1.06Q_r$
	N/A	ΔP	$0.93\Delta P_r$ to $1.06\Delta P_r$	$0.90\Delta P_r$ to $<0.93\Delta P_r$	$<0.90\Delta P_r$	$>1.06\Delta P_r$
	<600 rpm	V_v [Note (3)]	≤ 0.125 in./sec (≤ 0.3 cm/s)	>0.125 in./sec to 0.300 in./sec (>0.3 cm/s to 0.7 cm/s)	None	>0.300 in./sec (>0.7 cm/s)
		V_d or V_v	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$ or >10.5 mils to 22 mils (>266.7 μm to 558.8 μm)	None	$>6V_r$ or >22 mils (>558.8 μm)
	≥ 600 rpm	V_v [Note (3)]	≤ 0.125 in./sec (≤ 0.3 cm/s)	>0.125 in./sec to 0.300 in./sec (>0.3 cm/s to 0.7 cm/s)	None	>0.300 in./sec (>0.7 cm/s)
		V_d or V_v	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$ or >0.325 in./sec to 0.7 in./sec (>0.8 cm/s to 1.7 cm/s)	None	$>6V_r$ or >0.7 in./sec (>1.7 cm/s)

GENERAL NOTE: The subscript r denotes reference value, the subscript v denotes vibration velocity reference value, and the subscript d denotes displacement.

NOTES:

- (1) Vibration parameter per Table ISTB-3000-1. V_r is vibration reference value in the selected units.
- (2) Refer to Figure ISTB-5223-1 to establish displacement limits for pumps with speeds ≥ 600 rpm or velocity limits for pumps with speeds < 600 rpm.
- (3) Pumps that will use the minimum reference value for one or more vibration points shall use trending analysis of measured vibration amplitudes in the frequency domain to assess performance at these locations (see ISTB-3540).

(a) The pump shall be operated at nominal motor speed for constant speed drives or at a speed adjusted to the reference point ($\pm 1\%$) for variable speed drives.

(b) The resistance of the system shall be varied until the flow rate is as close as practical to the reference point with the variance not to exceed $+2\%$ or -1% of the reference point. The differential pressure shall then be determined and compared to its reference value. Alternatively, the flow rate shall be varied until the differential pressure is as close as practical to the reference point with the variance not to exceed $+1\%$ or -2% of the reference point and the flow rate determined and compared with the reference flow rate.

(c) Where it is not practical to vary system resistance, flow rate and pressure shall be determined and compared to their respective reference values.

(d) Vibration (displacement or velocity) shall be determined and compared with the reference value. Vibration measurements shall be an overall value, without filtering, of velocity or displacement. If velocity measurements are used, they shall be peak. If displacement amplitudes are used, they shall be peak-to-peak.

(e) All deviations from the reference values shall be compared with the ranges of Table ISTB-5121-1 and corrective action taken as specified in ISTB-6200. Vibration measurements shall be compared to both the relative and absolute criteria shown in the alert and required

action ranges of [Table ISTB-5121-1](#). For example, if vibration exceeds either $6V_r$ or 0.7 in./sec (1.7 cm/s) the pump is in the required action range.

ISTB-5122 Group B Test Procedure. Group B tests shall be conducted with the pump operating as close as practical to a specified reference value. The test parameter value identified in [Table ISTB-3000-1](#) shall be determined and recorded as required by this paragraph. The test shall be conducted as follows:

(a) The pump shall be operated at nominal motor speed for constant speed drives or at a speed adjusted to the reference point ($\pm 1\%$) for variable speed drives.

(b) The differential pressure or flow rate shall be determined and compared to its reference value.

(c) System resistance may be varied as necessary to achieve a value as close as practical to the reference value.

(d) A differential pressure or flow rate deviation from its reference value shall be compared with the ranges of [Table ISTB-5121-1](#) and corrective action taken as specified in [ISTB-6200](#).

- (22) **ISTB-5123 Comprehensive Test Procedure.** Comprehensive tests shall be conducted with the pump operating as close as practical to a specified reference point and within the variances from the reference point as described in this paragraph. The test parameters shown in [Table ISTB-3000-1](#) shall be determined and recorded as required by this paragraph. The test shall be conducted as follows:

(a) The pump shall be operated at nominal motor speed for constant speed drives or at a speed adjusted to the reference point ($\pm 1\%$) for variable speed drives.

(b) The resistance of the system shall be varied until the flow rate is as close as practical to the reference point with the variance not to exceed $+2\%$ or -1% of the reference point. The differential pressure shall then be determined and compared to its reference value. Alternatively, the flow rate shall be varied until the differential pressure is as close as practical to the reference point with the variance not to exceed $+1\%$ or -2% of the reference point and the flow rate determined and compared with the reference flow rate.

(c) Where it is not practical to vary system resistance, flow rate and pressure shall be determined and compared to their respective reference values.

(d) Vibration (displacement or velocity) shall be determined and compared with corresponding reference values. Vibration measurements are to be an overall value, without filtering, of velocity or displacement. If velocity measurements are used, they shall be peak. If displacement amplitudes are used, they shall be peak-to-peak.

(e) All deviations from the reference values shall be compared with the ranges of [Table ISTB-5121-1](#) and corrective action taken as specified in [ISTB-6200](#). The vibration measurements shall be compared to both the

relative and absolute criteria shown in the alert and required action ranges of [Table ISTB-5121-1](#). For example, if vibration exceeds either $6V_r$ or 0.7 in./sec (1.7 cm/s), the pump is in the required action range.

ISTB-5124 Periodic Verification Test.³ Tests shall be performed for pumps identified via [ISTB-1400\(d\)](#). If the required flow and differential pressure cannot be achieved, then the pump is in the action range, and corrective actions shall be taken in accordance with [ISTB-6200\(b\)](#).

ISTB-5200 Vertical Line Shaft Centrifugal Pumps

(a) Duration of Tests

(1) For the Group A test and the comprehensive test, after pump conditions are as stable as the system permits, each pump shall be run at least 2 min. At the end of this time at least one measurement or determination of each of the quantities required by [Table ISTB-3000-1](#) shall be made and recorded.

(2) For the Group B test, after pump conditions are stable, at least one measurement or determination of the quantity required by [Table ISTB-3000-1](#) shall be made and recorded.

(b) Bypass Loops

(1) A bypass test loop may be used for a Group A test or comprehensive test, provided the flow rate through the loop meets the requirements as specified in [ISTB-3300](#).

(2) A bypass test loop may be used for Group B tests if it is designed to meet the pump manufacturer's operating specifications (e.g., flow rate, time limitations) for minimum flow operation.

ISTB-5210 Baseline Testing. The parameters to be measured are specified in [Table ISTB-3000-1](#).

(a) In systems where resistance can be varied, flow rate and differential pressure shall be measured at a minimum of five points. If practicable, these points shall be from pump minimum flow to at least the comprehensive pump test flow rate, or, if a pump periodic verification test is required per [ISTB-3400](#), the pump design basis accident flow rate in the credited Owner's safety analysis, whichever is higher. A pump curve shall be established based on the measured points. At least one point shall be designated as the reference point(s). Data taken at the reference point will be used to compare the results of inservice tests. A pump curve need not be established for pumps in systems where resistance cannot be varied.

(b) Vibration measurements are only required to be taken at the reference point(s).

³ The Owner is not required to perform a pump periodic verification test if the design basis accident flow rate in the Owner's safety analysis is bounded by the comprehensive pump test flow rate or Group A test flow rate.

Table ISTB-5221-1
Vertical Line Shaft Centrifugal Pump Test Acceptance Criteria

Test Type	Pump Speed	Test Parameter	Acceptable Range	Alert Range	Required Action Range	
					Low	High
Group A test [Notes (1), (2)]	N/A	Q	$0.95Q_r$ to $1.10Q_r$	$0.93Q_r$ to $<0.95Q_r$	$<0.93Q_r$	$>1.10Q_r$
	N/A	ΔP	$0.95\Delta P_r$ to $1.10\Delta P_r$	$0.93\Delta P_r$ to $<0.95\Delta P_r$	$<0.93\Delta P_r$	$>1.10\Delta P_r$
	<600 rpm	V_v [Note (3)]	≤ 0.125 in./sec (≤ 0.3 cm/s)	>0.125 in./sec to 0.300 in./sec (>0.3 cm/s to 0.7 cm/s)	None	>0.300 in./sec (>0.7 cm/s)
		V_d or V_v	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$ or >10.5 mils to 22 mils (>266.7 μm to 558.8 μm)	None	$>6V_r$ or >22 mils (>558.8 μm)
	≥ 600 rpm	V_v [Note (3)]	≤ 0.125 in./sec (≤ 0.3 cm/s)	>0.125 in./sec to 0.300 in./sec (>0.3 cm/s to 0.7 cm/s)	None	>0.300 in./sec (>0.7 cm/s)
		V_d or V_v	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$ or >0.325 in./sec to 0.7 in./sec (>0.8 cm/s to 1.7 cm/s)	None	$>6V_r$ or >0.7 in./sec (>1.7 cm/s)
Group B test	N/A	Q , or	$0.90Q_r$ to $1.10Q_r$	None	$<0.90Q_r$	$>1.10Q_r$
	N/A	Δp	$0.90\Delta P_r$ to $1.10\Delta P_r$	None	$<0.90\Delta P_r$	$>1.10\Delta P_r$
Comprehensive test [Notes (1), (2)]	N/A	Q	$0.95Q_r$ to $1.06Q_r$	$0.93Q_r$ to $<0.95Q_r$	$<0.93Q_r$	$>1.06Q_r$
	N/A	ΔP	$0.95\Delta P_r$ to $1.06\Delta P_r$	$0.93\Delta P_r$ to $<0.95\Delta P_r$	$<0.93\Delta P_r$	$>1.06\Delta P_r$
	<600 rpm	V_v [Note (3)]	≤ 0.125 in./sec (≤ 0.3 cm/s)	>0.125 in./sec to 0.300 in./sec (>0.3 cm/s to 0.7 cm/s)	None	>0.300 in./sec (>0.7 cm/s)
		V_d or V_v	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$ or >10.5 mils to 22 mils (>266.7 μm to 558.8 μm)	None	$>6V_r$ or >22 mils (>558.8 μm)
	≥ 600 rpm	V_v [Note (3)]	≤ 0.125 in./sec (≤ 0.3 cm/s)	>0.125 in./sec to 0.300 in./sec (>0.3 cm/s to 0.7 cm/s)	None	>0.300 in./sec (>0.7 cm/s)
		V_d or V_v	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$ or >0.325 in./sec to 0.7 in./sec (>0.8 cm/s to 1.7 cm/s)	None	$>6V_r$ or >0.7 in./sec (>1.7 cm/s)

GENERAL NOTE: The subscript r denotes reference value, the subscript v denotes vibration velocity reference value, and the subscript d denotes displacement.

NOTES:

- (1) Vibration parameter per Table ISTB-3000-1. V_r is vibration reference value in the selected units.
- (2) Refer to Figure ISTB-5223-1 to establish displacement limits for pumps with speeds ≥ 600 rpm or velocity limits for pumps with speeds < 600 rpm.
- (3) Pumps that will use the minimum reference value for one or more vibration points shall use trending analysis of measured vibration amplitudes in the frequency domain to assess performance at these locations (see ISTB-3540).

ISTB-5220 Inservice Testing

- (22) **ISTB-5221 Group A Test Procedure.** Group A tests shall be conducted with the pump operating as close as practical to a specified reference point and within the variances from the reference point as described in this paragraph. The test parameters shown in Table ISTB-3000-1 shall be determined and recorded as required by this paragraph. The test shall be conducted as follows:

(a) The pump shall be operated at nominal motor speed for constant speed drives or at a speed adjusted to the reference point ($\pm 1\%$) for variable speed drives.

(b) The resistance of the system shall be varied until the flow rate is as close as practical to the reference point with the variance not to exceed $+2\%$ or -1% of the reference point. The differential pressure shall then be determined and compared to its reference value. Alternatively, the flow rate shall be varied until the differential pressure is as close as practical to the reference point with the variance not to exceed $+1\%$ or -2% of the reference point and the flow rate determined and compared with the reference flow rate.

(c) Where it is not practical to vary system resistance, flow rate and pressure shall be determined and compared to their respective reference values.

(d) Vibration (displacement or velocity) shall be determined and compared with the reference value. Vibration measurements shall be an overall value, without filtering, of velocity or displacement. If velocity measurements are used, they shall be peak. If displacement amplitudes are used, they shall be peak-to-peak.

(e) All deviations from the reference values shall be compared with the ranges of [Table ISTB-5221-1](#) and corrective action taken as specified in [ISTB-6200](#). Vibration measurements shall be compared to both the relative and absolute criteria shown in the alert and required action ranges of [Table ISTB-5221-1](#). For example, if vibration exceeds either $6V_r$ or 0.7 in./sec (1.7 cm/s), the pump is in the required action range.

ISTB-5222 Group B Test Procedure. Group B tests shall be conducted with the pump operating as close as practical to a specified reference value. The test parameter value identified in [Table ISTB-3000-1](#) shall be determined and recorded as required by this paragraph. The test shall be conducted as follows:

(a) The pump shall be operated at nominal motor speed for constant speed drives or at a speed adjusted to the reference point ($\pm 1\%$) for variable speed drives.

(b) The differential pressure or flow rate shall be determined and compared to its reference value.

(c) System resistance may be varied as necessary to achieve a value as close as practical to the reference value.

(d) A differential pressure or flow rate deviation from its reference value shall be compared with the ranges of [Table ISTB-5221-1](#) and corrective action taken as specified in [ISTB-6200](#).

(22) **ISTB-5223 Comprehensive Test Procedure.** Comprehensive tests shall be conducted with the pump operating as close as practical to a specified reference point and within the variances from the reference point as described in this paragraph. The test parameters shown in [Table ISTB-3000-1](#) shall be determined and recorded as required by this paragraph. The test shall be conducted as follows:

(a) The pump shall be operated at nominal motor speed for constant speed drives or at a speed adjusted to the reference point ($\pm 1\%$) for variable speed drives.

(b) The resistance of the system shall be varied until the flow rate is as close as practical to the reference point with the variance not to exceed $+2\%$ or -1% of the reference point. The differential pressure shall then be determined and compared to its reference value. Alternatively, the flow rate shall be varied until the differential pressure is as close as practical to the reference point with the variance not to exceed $+1\%$ or -2% of the reference point and the flow rate determined and compared with the reference flow rate.

(c) Where it is not practical to vary system resistance, flow rate and pressure shall be determined and compared to their respective reference values.

(d) Vibration (displacement or velocity) shall be determined and compared with corresponding reference values. Vibration measurements are to be an overall value, without filtering, of velocity or displacement. If velocity measurements are used, they shall be peak. If displacement amplitudes are used, they shall be peak-to-peak. (See [Figure ISTB-5223-1](#).)

(e) All deviations from the reference values shall be compared with the ranges of [Table ISTB-5221-1](#) and corrective action taken as specified in [ISTB-6200](#). The vibration measurements shall be compared to both the relative and absolute criteria shown in the alert and required action ranges of [Table ISTB-5221-1](#). For example, if vibration exceeds either $6V_r$ or 0.7 in./sec (1.7 cm/s), the pump is in the required action range.

ISTB-5224 Periodic Verification Test.³ Tests shall be performed for pumps identified via [ISTB-1400\(d\)](#). If the required flow and differential pressure cannot be achieved, then the pump is in the action range, and corrective actions shall be taken in accordance with [ISTB-6200\(b\)](#).

ISTB-5300 Positive Displacement Pumps

(a) Duration of Tests

(1) For the Group A test and the comprehensive test, after pump conditions are as stable as the system permits, each pump shall be run at least 2 min. At the end of this time at least one measurement or determination of each of the quantities required by [Table ISTB-3000-1](#) shall be made and recorded.

(2) For the Group B test, after pump conditions are stable, at least one measurement or determination of the quantity required by [Table ISTB-3000-1](#) shall be made and recorded.

(b) *Bypass Loops.* A bypass test loop may be used for a Group A test or comprehensive test, provided the flow rate through the loop meets the requirements as specified in [ISTB-3300](#). A bypass test loop may be used for Group B tests if it is designed to meet the pump manufacturer's operating specifications (e.g., flow rate, time limitations) for minimum flow operation.

ISTB-5310 Baseline Testing. The parameters to be measured are specified in [Table ISTB-3000-1](#).

(a) For positive displacement pumps, reference values shall be taken at or near pump design pressure for the parameters specified in [Table ISTB-3000-1](#).

(b) Vibration measurements are only required to be taken at the reference point(s).

ISTB-5320 Inservice Testing

ISTB-5321 Group A Test Procedure. Group A tests (22) shall be conducted with the pump operating as close as practical to a specified reference point and within the variances from the reference point as described in this paragraph. The test parameters shown in

Figure ISTB-5223-1
Vibration Limits

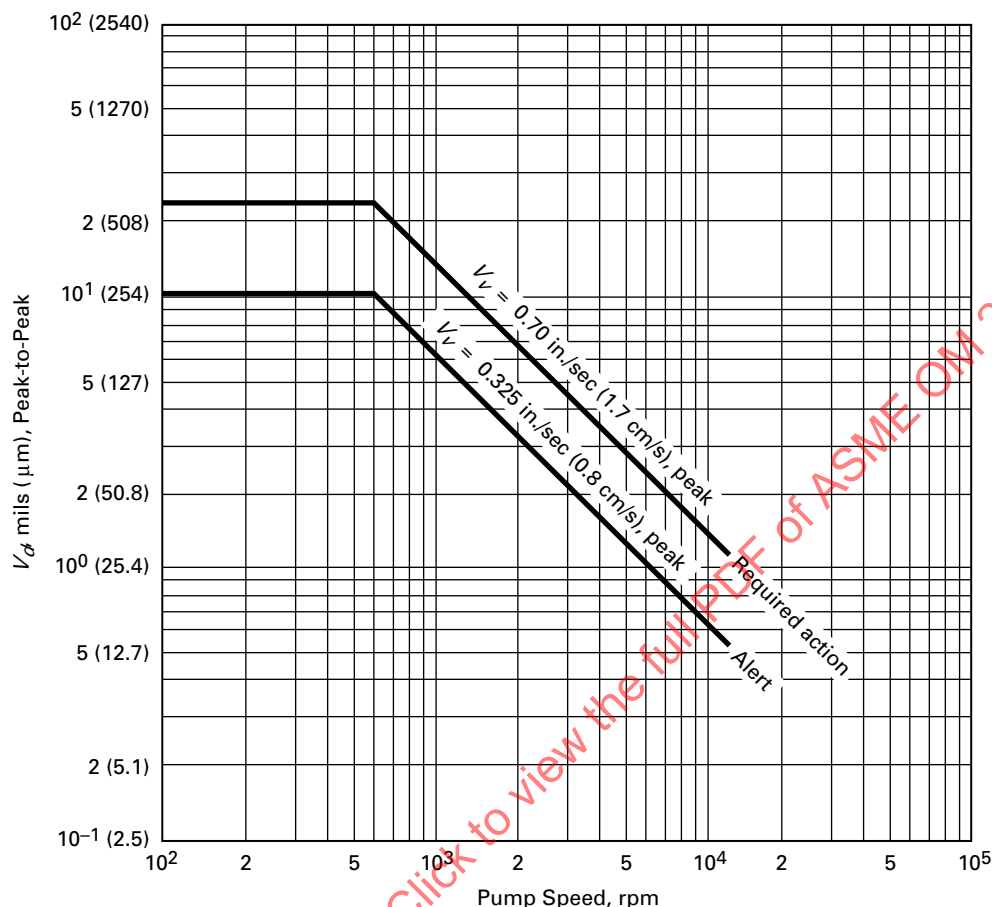


Table ISTB-3000-1 shall be determined and recorded as required by this paragraph. The test shall be conducted as follows:

(a) The pump shall be operated at nominal motor speed for constant speed drives or at a speed adjusted to the reference point ($\pm 1\%$) for variable speed drives. e

(b) The resistance of the system shall be varied until the discharge pressure is as close as practical to the reference point with the variance not to exceed $+1\%$ or -2% of the reference point. The flow rate shall then be determined and compared to its reference value.

(c) Where it is not practical to vary system resistance, flow rate and pressure shall be determined and compared to their respective reference values.

(d) Vibration (displacement or velocity) shall be determined and compared with the reference value. Vibration measurements shall be an overall value, without filtering, of velocity or displacement. If velocity measurements are used, they shall be peak. If displacement amplitudes are used, they shall be peak-to-peak.

(e) All deviations from the reference values shall be compared with the ranges of Table ISTB-5321-1 or Table ISTB-5321-2, as applicable, and corrective action taken as specified in ISTB-6200. For reciprocating positive displacement pumps, vibration measurements shall be compared to the relative criteria shown in the alert and required action ranges of Table ISTB-5321-2. For all other positive displacement pumps, vibration measurements shall be compared to both the relative and absolute criteria shown in the alert and required action ranges of Table ISTB-5321-1. For example, if vibration exceeds either $6V_r$ or 0.7 in./sec (1.7 cm/s), the pump is in the required action range.

ISTB-5322 Group B Test Procedure. Group B tests shall be conducted with the pump operating as close as practical to a specified reference value. The test parameter value identified in Table ISTB-3000-1 shall be determined and recorded as required by this paragraph. The test shall be conducted as follows:

Table ISTB-5321-1
Positive Displacement Pump (Except Reciprocating) Test Acceptance Criteria

(22)

Test Type	Pump Speed	Test Parameter	Acceptable Range	Alert Range	Required Action Range	
					Low	High
Group A test [Notes (1), (2)]	N/A	Q	$0.95Q_r$ to $1.10Q_r$	$0.93Q_r$ to $<0.95Q_r$	$<0.93Q_r$	$>1.10Q_r$
	N/A	P	$0.93P_r$ to $1.10P_r$	$0.90P_r$ to $<0.93P_r$	$<0.90P_r$	$>1.10P_r$
	<600 rpm	V_v [Note (3)]	≤ 0.125 in./sec (≤ 0.3 cm/s)	>0.125 in./sec to 0.300 in./sec (>0.3 cm/s to 0.7 cm/s)	None	>0.300 in./sec (>0.7 cm/s)
		V_d or V_v	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$ or >10.5 mils to 22 mils (>266.7 μm to 558.8 μm)	None	$>6V_r$ or >22 mils (>558.8 μm)
	≥ 600 rpm	V_v [Note (3)]	≤ 0.125 in./sec (≤ 0.3 cm/s)	>0.125 in./sec to 0.300 in./sec (>0.3 cm/s to 0.7 cm/s)	None	>0.300 in./sec (>0.7 cm/s)
		V_d or V_v	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$ or >0.325 in./sec to 0.7 in./sec (>0.8 cm/s to 1.7 cm/s)	None	$>6V_r$ or >0.7 in./sec (>1.7 cm/s)
Group B test	N/A	Q	$0.90Q_r$ to $1.10Q_r$	None	$<0.90Q_r$	$>1.10Q_r$
Comprehensive test [Notes (1), (2)]	N/A	Q	$0.95Q_r$ to $1.06Q_r$	$0.93Q_r$ to $<0.95Q_r$	$<0.93Q_r$	$>1.06Q_r$
	N/A	P	$0.93P_r$ to $1.06P_r$	$0.90P_r$ to $<0.93P_r$	$<0.90P_r$	$>1.06P_r$
	<600 rpm	V_v [Note (3)]	≤ 0.125 in./sec (≤ 0.3 cm/s)	>0.125 in./sec to 0.300 in./sec (>0.3 cm/s to 0.7 cm/s)	None	>0.300 in./sec (>0.7 cm/s)
		V_d or V_v	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$ or >10.5 mils to 22 mils (>266.7 μm to 558.8 μm)	None	$>6V_r$ or >22 mils (>558.8 μm)
	≥ 600 rpm	V_v [Note (3)]	≤ 0.125 in./sec (≤ 0.3 cm/s)	>0.125 in./sec to 0.300 in./sec (>0.3 cm/s to 0.7 cm/s)	None	>0.300 in./sec (>0.7 cm/s)
		V_d or V_v	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$ or >0.325 in./sec to 0.7 in./sec (>0.8 cm/s to 1.7 cm/s)	None	$>6V_r$ or >0.7 in./sec (>1.7 cm/s)

GENERAL NOTE: The subscript r denotes reference value, the subscript v denotes vibration velocity reference value, and the subscript d denotes displacement.

NOTES:

- (1) Vibration parameter per Table ISTB-3000-1. V_r is vibration reference value in the selected units.
- (2) Refer to Figure ISTB-5223-1 to establish displacement limits for pumps with speeds ≥ 600 rpm or velocity limits for pumps with speeds < 600 rpm.
- (3) Pumps that will use the minimum reference value for one or more vibration points shall use trending analysis of measured vibration amplitudes in the frequency domain to assess performance at these locations (see ISTB-3540).

(a) The pump shall be operated at nominal motor speed for constant speed drives or at a speed adjusted to the reference point ($\pm 1\%$) for variable speed drives.

(b) The flow rate shall be determined and compared to its reference value.

(c) System resistance may be varied as necessary to achieve a value as close as practical to the reference value.

(d) A flow rate deviation from its reference value shall be compared with the ranges of Table ISTB-5321-1 or Table ISTB-5321-2, as applicable, and corrective action taken as specified in ISTB-6200.

- (22) **ISTB-5323 Comprehensive Test Procedure.** Comprehensive tests shall be conducted with the pump operating as close as practical to a specified reference point and within the variances from the reference point as described in this paragraph. The test parameters shown in Table ISTB-3000-1 shall be determined and recorded

as required by this paragraph. The test shall be conducted as follows:

(a) The pump shall be operated at nominal motor speed for constant speed drives or at a speed adjusted to the reference point ($\pm 1\%$) for variable speed drives.

(b) The resistance of the system shall be varied until the discharge pressure is as close as practical to the reference point with the variance not to exceed $+1\%$ or -2% of the reference point. The flow rate shall then be determined and compared to its reference value.

(c) Where it is not practical to vary system resistance, flow rate and pressure shall be determined and compared to their respective reference values.

(d) Vibration (displacement or velocity) shall be determined and compared with corresponding reference values. Vibration measurements are to be an overall value, without filtering, of velocity or displacement. If velocity measurements are used, they shall be peak. If

Table ISTB-5321-2
Reciprocating Positive Displacement Pump Test Acceptance Criteria

(22)

Test Type	Pump Speed	Test Parameter	Acceptable Range	Alert Range	Required Action Range	
					Low	High
Group A test	N/A	Q	$0.95Q_r$ to $1.10Q_r$	$0.93Q_r$ to $<0.95Q_r$	$<0.93Q_r$	$>1.10Q_r$
	N/A	P	$0.93P_r$ to $1.10P_r$	$0.90P_r$ to $<0.93P_r$	$<0.90P_r$	$>1.10P_r$
	N/A	V_v [Note (1)]	≤ 0.125 in./sec (≤ 0.3 cm/s)	>0.125 in./sec to 0.300 in./sec (>0.3 cm/s to 0.7 cm/s)	None	>0.300 in./sec (>0.7 cm/s)
	N/A	V_d or V_v	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$	None	$>6V_r$
Group B test	N/A	Q	$0.90Q_r$ to $1.10Q_r$	None	$<0.90Q_r$	$>1.10Q_r$
Comprehensive test	N/A	Q	$0.95Q_r$ to $1.06Q_r$	$0.93Q_r$ to $<0.95Q_r$	$<0.93Q_r$	$>1.06Q_r$
	N/A	P	$0.93P_r$ to $1.06P_r$	$0.90P_r$ to $<0.93P_r$	$<0.90P_r$	$>1.06P_r$
	N/A	V_v [Note (1)]	≤ 0.125 in./sec (≤ 0.3 cm/s)	>0.125 in./sec to 0.300 in./sec (>0.3 cm/s to 0.7 cm/s)	None	>0.300 in./sec (>0.7 cm/s)
	N/A	V_d or V_v	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$	None	$>6V_r$

GENERAL NOTE: The subscript r denotes reference value, the subscript v denotes vibration velocity reference value, and the subscript d denotes displacement.

NOTE: (1) Pumps that will use the minimum reference value for one or more vibration points shall use trending analysis of measured vibration amplitudes in the frequency domain to assess performance at these locations (see [ISTB-3540](#)).

displacement amplitudes are used, they shall be peak-to-peak.

(e) All deviations from the reference values shall be compared with the ranges of [Table ISTB-5321-1](#) or [Table ISTB-5321-2](#), as applicable, and corrective action taken as specified in [ISTB-6200](#). For reciprocating positive displacement pumps, vibration measurements shall be compared to the relative criteria shown in the alert and required action ranges of [Table ISTB-5321-2](#). For all other positive displacement pumps, vibration measurements shall be compared to both the relative and absolute criteria shown in the alert and required action ranges of [Table ISTB-5321-1](#). For example, if vibration exceeds either $6V_r$ or 0.7 in./sec (1.7 cm/s), the pump is in the required action range.

ISTB-5324 Periodic Verification Test.³ Tests shall be performed for pumps identified via [ISTB-1400\(d\)](#). If the required flow and differential pressure cannot be achieved, then the pump is in the action range, and corrective actions shall be taken in accordance with [ISTB-6200\(b\)](#).

ISTB-6000 MONITORING, ANALYSIS, AND EVALUATION

If anomalous data were obtained during a test with no clear indication of systematic error, then the cause shall be attributed to the pump under the test, and [ISTB-6200](#) applies. If it's readily apparent that the anomalous data were caused by a systematic error, such as improper system lineup or inaccurate instrumentation, then [ISTB-6300](#) applies.

ISTB-6100 Trending

Test parameters shown in [Table ISTB-3000-1](#), except for fixed values, shall be trended.

ISTB-6200 Corrective Action

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

(b) *Action Range.* If the pump periodic verification test flow or pressure parameter is not met or a measured test parameter value falls within the required action range of [Table ISTB-5121-1](#), [Table ISTB-5221-1](#), [Table ISTB-5321-1](#), or [Table ISTB-5321-2](#), as applicable, the pump shall be declared inoperable until either the cause of the deviation has been determined and the condition is corrected, or an analysis of the pump is performed in accordance with (c).

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

established and shall justify the adequacy of the new reference values, if applicable. The results of this analysis shall be documented in the record of tests (see [ISTB-9000](#)).

ISTB-6300 Systematic Error

When a test shows measured parameter values that fall outside of the acceptable range of [Table ISTB-5121-1](#), [Table ISTB-5221-1](#), [Table ISTB-5321-1](#), or [Table ISTB-5321-2](#), as applicable, that have resulted from an identified systematic error, such as improper system lineup or inaccurate instrumentation, the test shall be rerun after correcting the error.

ISTB-6400 Analysis of Related Conditions

If the reference value of a particular parameter being measured or determined can be significantly influenced by other related conditions, then these conditions shall be analyzed⁴ and documented in the record of tests (see [ISTB-9000](#)).

ISTB-7000 TO BE PROVIDED AT A LATER DATE

ISTB-8000 TO BE PROVIDED AT A LATER DATE

ISTB-9000 RECORDS AND REPORTS

ISTB-9100 Pump Records

The Owner shall maintain a record that shall include the following for each pump covered by this Subsection:

(a) the manufacturer and the manufacturer's model and serial or other identification number

(b) a copy or summary of the manufacturer's acceptance test report if available

(c) a copy of the pump manufacturer's operating limits

(d) the comprehensive pump test flow rate basis (e.g., flow rate and associated differential or discharge pressure and speed for variable speed pumps)

(e) maintaining the necessary records for the pump periodic verification tests, including the applicable test parameters (e.g., flow rate and associated differential pressure, or flow rate and associated discharge pressure, and speed for variable speed pumps) and their basis

ISTB-9200 Test Plans

In addition to the requirements of [ISTA-3110](#) and [ISTA-3160](#), the test plans and procedures shall include the following:

(a) category of each pump

(b) the hydraulic circuit to be used

(c) the location and type of measurement for the required test parameters

(d) the method of determining test parameter values that are not directly measured by instrumentation

ISTB-9300 Record of Tests

See [ISTA-9230](#).

ISTB-9400 Record of Corrective Action

See [ISTA-9240](#).

⁴Vibration measurements of pumps may be foundation, driver, or piping dependent. Therefore, if initial vibration readings are high and have no obvious relationship to the pump, then vibration measurements should be taken at the driver, at the foundation, and on the piping and analyzed to ensure that the reference vibration measurements are representative of the pump and the measured vibration levels will not prevent the pump from fulfilling its function.

Subsection ISTC

Inservice Testing of Valves in Water-Cooled Reactor Nuclear Power Plants

ISTC-1000 INTRODUCTION

ISTC-1100 Applicability

The requirements of this Subsection apply to certain valves and pressure relief devices (and their actuating and position-indicating systems).

(22) ISTC-1200 Exclusions

The following components are excluded from the testing requirements of this Subsection:

(a) valves that are not required to perform a specific function as described in [ISTA-1100](#)

(1) valves used only for operating convenience such as vent, drain, instrument, and test valves

(2) valves used only for system control, such as pressure-regulating valves

(3) valves used only for system or component maintenance

(b) skid-mounted valves that are tested as part of the major component and are justified by the Owner to be adequately tested

(c) external control and protection systems responsible for sensing plant conditions and providing signals for valve operation

(d) safety and relief valves are excluded from the requirements of [ISTC-3500](#) and [ISTC-3700](#)

(e) nonreclosing pressure relief devices (rupture disks) used in boiling water reactor (BWR) scram accumulators

ISTC-1300 Valve Categories

Valves within the scope of this Subsection shall be placed in one or more of the following categories. Where specified in [Table ISTC-3500-1](#), when more than one distinguishing category characteristic is applicable, all requirements of each of the individual categories are applicable, although duplication or repetition of common testing requirements is not necessary.

(a) *Category A*: valves for which seat leakage is limited to a specific maximum amount in the closed position for fulfillment of their required function(s), as specified in [ISTA-1100](#).

(b) *Category B*: valves for which seat leakage in the closed position is inconsequential for fulfillment of the required function(s), as specified in [ISTA-1100](#).

(c) *Category C*: valves that are self-actuating in response to some system characteristic, such as pressure (relief valves) or flow direction (check valves) for fulfillment of the required function(s), as specified in [ISTA-1100](#).

(d) *Category D*: valves that are actuated by an energy source capable of only one operation, such as rupture disks or explosively actuated valves.

ISTC-1400 Owner's Responsibility

In addition to the requirements of [ISTA-1500](#), it is the Owner's responsibility to

(a) include in the plant design all necessary instrumentation, test connections, flow instruments, or any other provisions that are required to fully comply with the requirements of this Subsection.

(b) categorize (see [ISTC-1300](#)), and list in the plant records (see [ISTC-9000](#)) each valve to be tested in accordance with the rules of this Subsection, including Owner-specified acceptance criteria. The Owner shall specify test conditions.

(c) ensure that the application, method, and capability of each nonintrusive technique is qualified.

ISTC-2000 SUPPLEMENTAL DEFINITIONS

The following are provided to ensure a uniform understanding of selected terms used in this Subsection:

full-stroke time: the time interval from initiation of the actuating signal to the indication of the end of the operating stroke.

power-operated relief valve (PORV): a power-operated valve that can perform a pressure-relieving function and is remotely actuated by either a signal from a pressure-sensing device or a control switch. A PORV is not capacity certified under ASME Boiler and Pressure Vessel Code (ASME BPVC), Section III overpressure protection requirements.

reactor coolant system pressure isolation: that function that prevents intersystem overpressurization between the reactor coolant system and connected low pressure systems.

ISTC-3000 GENERAL TESTING REQUIREMENTS

(22) ISTC-3100 Preservice Testing

Each valve shall be tested during the preservice test period as required by this Subsection. These tests shall be conducted under conditions as near as practicable to those expected during subsequent inservice testing. Only one preservice test of each valve is required with these exceptions.

(a) Any valve that has undergone maintenance that could affect its performance after the preservice test shall be tested in accordance with [ISTC-3310](#).

(b) Safety and relief valves and nonreclosing pressure relief devices shall meet the preservice test requirements of [Division 1, Mandatory Appendix I](#).

(c) Active motor-operated valves (MOV) shall meet the preservice test requirements of [Division 1, Mandatory Appendix III](#).

(d) For post-2000 plants, Category D explosively actuated valves shall be preservice tested as follows:

(1) Verify the operational readiness of the actuation logic and associated electrical circuits for each valve with its pyrotechnic charge removed from the valve. This must include confirmation that sufficient electrical parameters (voltage, current, resistance) are available at the valve from each circuit that is relied upon to actuate the valve.

(2) Following fabrication, select a sample of pyrotechnic charges for testing. The sample shall include a quantity of charges equal to at least 20% of the number of charges of each size installed in the plant, and include at least one charge from each manufacturer batch. The sample may include charges tested to qualify the batch. If the charges are removed after they have been installed in the plant, the sampling shall include a charge from at least one explosively actuated valve from each redundant safety train.

Test each selected charge either in a valve or in a qualified test fixture to confirm the capability to provide the necessary motive force to operate the valve to perform its intended function without damage to the valve body or connected piping.

(3) Resolve any deficiencies identified in the operational readiness of the actuation logic or associated electrical circuits or the capability of a pyrotechnic charge. If a charge fails to fire or its capability is not confirmed, all charges with the same batch number shall be removed, discarded, and replaced with charges per [ISTC-5260\(d\)](#).

(e) Active pneumatically operated valves (AOV) shall meet the Preservice Test requirements of [Division 1, Mandatory Appendix IV](#).

ISTC-3200 Inservice Testing

Inservice testing in accordance with this Subsection shall commence when the valves are required to be operable to fulfill their required function(s) (see [ISTA-1100](#)).

ISTC-3300 Reference Values

(22)

Reference values shall be determined from the results of preservice testing or from the results of inservice testing. These tests shall be performed under conditions as near as practicable to those expected during subsequent inservice testing.

Reference values shall be established only when the valve is known to be operating acceptably. If the particular parameter being measured can be significantly influenced by other related conditions, then these conditions shall be analyzed.

The requirements of this paragraph are not applicable to active MOVs. Refer to [Division 1, Mandatory Appendix III](#) for requirements applicable to active MOVs.

ISTC-3310 Effects of Valve Repair, Replacement, or

Maintenance on Reference Values. When a valve or its control system has been replaced, repaired, or has undergone maintenance¹ that could affect the valve's performance, a new reference value shall be determined or the previous value reconfirmed by an inservice test run before the time it is returned to service or immediately if not removed from service. This test 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 shall be identified and analyzed. Verification that the new values represent acceptable operation shall be documented in the record of tests (see [ISTC-9120](#)). Safety and relief valves and nonreclosing pressure relief devices shall be tested as required by the replacement, repair, and maintenance requirements of [Division 1, Mandatory Appendix I](#).

Active MOVs shall be tested as required by the replacement, repair, and maintenance requirements of [Division 1, Mandatory Appendix III](#).

Active AOVs shall be tested as required by the replacement, repair, and maintenance requirements of [Division 1, Mandatory Appendix IV](#).

ISTC-3320 Establishment of Additional Set of Refer-

ence Values. If it is necessary or desirable for some reason, other than stated in [ISTC-3310](#), to establish additional reference values, an inservice test shall first be run at the conditions of an existing set of reference values, or, if impractical, at the conditions for which the new reference values are required, and the results analyzed. If operation

¹ Adjustment of stem packing, limit switches, or control system valves, and removal of the bonnet, stem assembly, actuator, obturator, or control system components are examples of maintenance that could affect valve performance parameters.

Table ISTC-3500-1
Inservice Test Requirements

(22)

Component Type [Note (1)]	Category A/B/C Exercise Category D Exam	Category A/B/C Position Indication	Category A Leakage Test [Note (2)]	Category A/B Other Performance Testing	Category A/B Fail Safe
Active pneumatically operated valves	ISTC-3500 ISTC-5130	ISTC-3700	ISTC-3600	Mandatory Appendix IV	ISTC-3560
Active motor-operated valves	ISTC-5120	Mandatory Appendix III	ISTC-3600	Mandatory Appendix III	ISTC-3560
PORVs	ISTC-5110	ISTC-5110	ISTC-5110	ISTC-5110	ISTC-5110
Other active power- operated valves	ISTC-3500	ISTC-3700	ISTC-3600	ISTC-5100	ISTC-3560
Active manual valves	ISTC-3540	ISTC-3700	ISTC-3600	None	ISTC-3560
All passive valves	N/A	ISTC-3700	ISTC-3600	None	None
Check valves [Note (3)]	ISTC-3500	ISTC-3700	ISTC-3600	None	None
Pressure relief devices	ISTC-5230 ISTC-5240 ISTC-5250	Mandatory Appendix I	Mandatory Appendix I	None	None
Explosively actuated devices	ISTC-5260	None	ISTC-3600	None	None

NOTES:

- (1) When more than one distinguishing category characteristic is applicable, all requirements of each of the individual categories are applicable, although duplication or repetition of common testing requirements is not necessary.
- (2) For valves with a leakage limit for the purposes of containment isolation, test per ISTC-3620.
- (3) If a check valve used for a pressure relief device is capacity certified, then it shall be classified as a pressure or vacuum relief device. If a check valve used to limit pressure is not capacity certified, then it shall be classified as a check valve.

is acceptable in accordance with the applicable requirements of ISTC-5100, a second test shall be performed under the new conditions as soon as practicable. The results of the second test shall establish the additional reference values. Whenever additional reference values are established, the reasons for doing so shall be justified and documented in the record of tests (see ISTC-9120).

ISTC-3400 To Be Provided at a Later Date

ISTC-3500 Valve Testing Requirements

Active and passive valves in the categories defined in ISTC-1300 shall be tested in accordance with the paragraphs specified in Table ISTC-3500-1 and the applicable requirements of ISTC-5100 and ISTC-5200.

- (22) **ISTC-3510 Exercising Test Frequency.** Active Category A, Category B, and Category C check valves shall be exercised nominally every 3 months, except as provided by ISTC-3520; ISTC-3540; ISTC-3550; ISTC-3570; ISTC-5221; ISTC-5222; and Division 1, Mandatory Appendix III. PORVs shall be exercise tested once per fuel cycle.

ISTC-3520 Exercising Requirements

- (22) **ISTC-3521 Category A and Category B Valves.** Category A and Category B valves shall be tested as follows:

(a) exercising of Category A and Category B valves during operation at power to the position(s) required to fulfill its function(s).

(b) if exercising is not practicable during operation at power, it may be limited to exercising during cold shutdown outages.

(c) if exercising is not practicable during operation at power or cold shutdown outages, it may be limited to exercising during refueling outages.

(d) valves exercised during cold shutdown outages shall be exercised during each cold shutdown outage, except as specified in (e). Such exercise is not required if the time period since the previous exercise is less than 3 months. During extended shutdowns, valves that are required to perform their intended function (see ISTA-1100) shall be exercised every 3 months, if practicable.

(e) valve exercising during cold shutdown outages shall commence within 48 hr of achieving the cold shutdown mode and continue until all testing is complete, with the following exceptions:

(1) The plant is ready to return to operation at power.

(2) For extended outages, testing need not be commenced within 48 hr, provided all valves required to be tested during cold shutdown outages will be tested before or as part of plant startup.

(3) For shorter duration outages, tests not completed in previous cold shutdown outage(s) should be preferentially selected for testing during subsequent cold shutdown outage(s) as plant conditions allow.

(4) As appropriate, valves may be tested upon the commencement of power reduction, while decreasing plant modes to the cold shutdown mode, during the cold shutdown mode, or while increasing plant modes to operation at power.

(5) If in the cold shutdown mode for less than 48 hr, no cold shutdown outage testing is required to be completed.

(f) all valve testing required to be performed during a refueling outage may begin upon the commencement of power reduction, as appropriate, but shall be completed before returning the plant to operation at power.

(g) The exercise requirements of this paragraph are not applicable to active MOVs. Refer to [Division 1, Mandatory Appendix III](#) for active MOV exercise requirements.

ISTC-3522 Category C Check Valves. Category C check valves shall be exercised as follows:

(a) During operation at power, each check valve shall be exercised or examined in a manner that verifies obturator travel by using the methods in [ISTC-5221](#).

Each check valve exercise test shall include open and close tests. Open and close tests need only be performed at an interval when it is practicable to perform both tests. Test order (e.g., whether the open test precedes the close test) shall be determined by the Owner. Open and close tests are not required to be performed at the same time if they are both performed within the same interval.

(b) If exercising is not practicable during operation at power, it shall be performed during cold shutdown outages.

(c) If exercising is not practicable during operation at power and cold shutdown outages, it shall be performed during refueling outages.

(d) Valves exercised during cold shutdown outages shall be exercised during each cold shutdown, except as specified in (e). Such exercise is not required if the interval since the previous exercise is less than 3 months. During extended shutdowns, valves that are required to perform their intended function (see [ISTA-1100](#)) shall be exercised every 3 months, if practicable.

(e) Valve exercising during cold shutdown outages shall commence within 48 hr of achieving the cold shutdown mode and continue until all testing is complete, with the following exceptions:

(1) The plant is ready to return to operation at power.

(2) For extended outages, testing need not be commenced within 48 hr, provided all valves required to be tested during cold shutdown outages will be tested before or as part of plant startup.

(3) For shorter duration outages, tests not completed in previous cold shutdown outage(s) should be preferentially selected for testing during subsequent cold shutdown outage(s) as plant conditions allow.

(4) As appropriate, valves may be tested upon the commencement of power reduction, while decreasing plant modes to the cold shutdown mode, during the cold shutdown mode, or while increasing plant modes to operation at power.

(5) If in the cold shutdown mode for less than 48 hr, no cold shutdown outage testing is required to be completed.

(f) All valve testing required to be performed during a refueling outage may begin upon the commencement of power reduction, as appropriate, but shall be completed before returning the plant to operation at power.

ISTC-3530 Valve Obturator Movement. The necessary valve obturator movement shall be determined by exercising the valve while observing an appropriate indicator, such as indicating lights that signal the required changes of obturator position, or by observing other evidence, such as changes in system pressure, flow rate, level, or temperature, that reflects change of obturator position.

ISTC-3540 Manual Valves. Manual valves shall be full-stroke exercised at least once every 2 yr, except where adverse conditions² may require the valve to be tested more frequently to ensure operational readiness. Any increased testing frequency shall be specified by the Owner. The valve shall exhibit the required change of obturator position.

ISTC-3550 Valves in Regular Use. Valves that operate in the course of plant operation at a frequency that would satisfy the exercising requirements of this Subsection need not be additionally exercised, provided that the observations otherwise required for testing are made and analyzed during such operation and recorded in the plant record at intervals no greater than specified in [ISTC-3510](#).

ISTC-3560 Fail-Safe Valves. Valves with fail-safe actuators shall be tested by observing the operation of the actuator upon loss of valve actuating power in accordance with the exercising frequency of [ISTC-3510](#). AOV fail-safe test frequency shall meet the requirements of [Division 1, Mandatory Appendix IV](#).

ISTC-3570 Valves Out of Service. For a valve declared (22) inoperable or not required to be operable, the exercising test schedule need not be followed. Within 3 months before placing the valve in an operable status, the valves shall be exercised and the schedule followed in accordance with requirements of this Subsection.

² Harsh service environment, lubricant hardening, corrosive or sediment-laden process fluid, or degraded valve components are some examples of adverse conditions.

ISTC-3600 Leak Testing Requirements

ISTC-3610 Scope of Seat Leakage Rate Test. Category A valves shall be leakage tested, except that valves that function in the course of plant operation in a manner that demonstrates functionally adequate seat leak-tightness need not be additionally leakage tested. In such cases, the valve record shall provide the basis for the conclusion that operational observations constitute satisfactory demonstration.

ISTC-3620 Containment Isolation Valves. Containment isolation valves with a leakage rate requirement based on Appendix J program commitment shall be tested in accordance with the Owner's 10 CFR 50, Appendix J program. Containment isolation valves with a leakage requirement based on other functions shall be tested in accordance with [ISTC-3630](#). Examples of these other functions are reactor coolant system pressure isolation valves and certain Owner-defined system functions such as inventory preservation, system protection, or flooding protection.

(22) **ISTC-3630 Leakage Rate for Other Than Containment Isolation Valves.** Category A valves with a leakage requirement not based on an Owner's 10 CFR 50, Appendix J program, shall be tested to verify their seat leakages within acceptable limits. Valve closure before seat leakage testing shall be by using the valve operator with no additional closing force applied.

(a) *Frequency.* Tests shall be conducted at least once every 2 yr.

(b) *Differential Test Pressure.* Valve seat tests shall be made with the pressure differential in the same direction as when the valve is performing its function, with the following exceptions:

(1) Globe-type valves may be tested with pressure under the seat.

(2) Butterfly valves may be tested in either direction, provided their seat construction is designed for sealing against pressure on either side.

(3) Double-disk gate valves may be tested by pressurizing between the disks.

(4) Leakage tests involving pressure differential lower than function pressure differentials are permitted in those types of valves in which service pressure will tend to diminish the overall leakage channel opening, as by pressing the disk into or onto the seat with greater force. Gate valves, check valves, and globe-type valves, having function pressure differential applied over the seat, are examples of valve applications satisfying this requirement. When leakage tests are made in such cases using pressures lower than function maximum pressure differential, the observed leakage shall be adjusted to the function maximum pressure differential value. The adjustment shall be made by calculation appropriate to the test media and the ratio between the test and function pressure differential, assuming leakage to be directly

proportional to the pressure differential to the one-half power.

(5) Valves not qualifying for reduced pressure testing as defined above shall be tested at full maximum function pressure differential.

(c) *Seat Leakage Measurement.* Valve seat leakage shall be determined by one of the following methods:

(1) measuring leakage through a downstream tell-tale connection while maintaining test pressure on one side of the valve

(2) measuring the feed rate required to maintain test pressure in the test volume or between two seats of a gate valve, provided the total apparent leakage rate is charged to the valve or valve combination or gate valve seat being tested and the conditions required by (b) are satisfied

(3) determining leakage by measuring pressure decay in the test volume, provided the total apparent leakage rate is charged to the valve or valve combination or gate valve seat being tested and the conditions required by (b) are satisfied

(d) *Test Medium.* The test medium shall be specified by the Owner.

(e) *Analysis of Leakage Rates.* Leakage rate measurements shall be compared with the permissible leakage rates specified by the plant Owner for a specific valve or valve combination. If leakage rates are not specified by the Owner, the following rates shall be permissible:

(1) for water, $0.5D$ gal/min ($12.4d$ mL/s) or 5 gal/min (315 mL/s), whichever is less, at function pressure differential

(2) for air, at function pressure differential, $7.5D$ standard ft³/day ($58d$ std. cc/min)

where

D = nominal valve size, in.

d = nominal valve size, cm

(f) *Corrective Action.* Valves or valve combinations with leakage rates exceeding the values specified by the Owner per (e) shall be declared inoperable and either repaired or replaced. A retest demonstrating acceptable operation shall be performed following any required corrective action before the valve is returned to service.

ISTC-3700 Position Verification Testing

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

Position verification for active MOVs shall be tested in accordance with [Division 1, Mandatory Appendix III](#).

ISTC-4000 INSTRUMENTATION AND TEST EQUIPMENT

Instrumentation and test equipment accuracy shall be considered when establishing valve test acceptance criteria.

ISTC-5000 SPECIFIC TESTING REQUIREMENTS

(22) ISTC-5100 Power-Operated Valves

All valves shall be tested in accordance with the applicable requirements of [ISTC-3000](#), and as identified below, except for power-operated control valves that only have a fail-safe safety function.

For power-operated control valves that only have a fail-safe safety function, the requirements for valve stroke-time measurement testing, the associated stroke-time test acceptance criteria, and any corrective actions that would result from stroke-time testing need not be met. For these valves, all other applicable requirements of [ISTC-3000](#), and as identified below, shall be met.

- (22) **ISTC-5110 Power-Operated Relief Valves.** PORVs shall meet the requirements of [ISTC-5100](#) for the specific Category B valve type and [ISTC-5240](#) for Category C valves.

ISTC-5111 Valve Testing Requirements

(a) Testing shall be performed in the following sequence or concurrently. If testing in the following sequence is impractical, it may be performed out of sequence, and a justification shall be documented in the record of tests for each test or in the test plan:

- (1) leakage testing
- (2) stroke testing
- (3) position indication testing

(b) The pressure-sensing device shall be calibrated in accordance with the Owner's QA program.

ISTC-5112 Leak Testing. Seat tightness of the PORV shall be verified by leak testing in accordance with the requirements of [Division 1, Mandatory Appendix I, I-4200](#) and [I-4220](#).

ISTC-5113 Valve Stroke Testing

(a) Active valves shall have their stroke times measured when exercised in accordance with [ISTC-3500](#).

(b) The limiting value(s) of full-stroke time of each valve shall be specified by the Owner.

(c) The stroke time of all valves shall be measured to at least the nearest second.

(d) Any abnormality or erratic action shall be recorded (see [ISTC-9120](#)), and an evaluation shall be made regarding need for corrective action.

(e) Stroke testing shall be performed during normal operating conditions for temperature and pressure if practicable.

ISTC-5114 Stroke Test Acceptance Criteria. Test results shall be compared to the reference values established in accordance with [ISTC-3300](#), [ISTC-3310](#), or [ISTC-3320](#).

(a) Valves with reference stroke times of greater than 10 sec shall exhibit no more than $\pm 25\%$ change in stroke time when compared to the reference value.

(b) Valves with reference stroke times of less than or equal to 10 sec shall exhibit no more than $\pm 50\%$ change in stroke time when compared to the reference value.

(c) Valves that stroke in less than 2 sec may be exempted from (b). In such cases the maximum limiting stroke time shall be 2 sec.

ISTC-5115 Corrective Action

(a) If a valve fails the applicable leak test acceptance criteria, to exhibit the required change of obturator position or exceeds the limiting values of full-stroke time [see [ISTC-5113\(b\)](#)], the valve shall be immediately declared inoperable.

(b) Valves with measured stroke times that do not meet the acceptance criteria of [ISTC-5114](#) shall be immediately retested or declared inoperable. If the valve is retested and the second set of data also does not meet the acceptance criteria, the data shall be analyzed within 96 hr to verify that the new stroke time represents acceptable valve operation, or the valve shall be declared inoperable. If the second set of data meets the acceptance criteria, the cause of the initial deviation shall be analyzed and the results documented in the record of tests (see [ISTC-9120](#)).

(c) Valves declared inoperable may be repaired, replaced, or the data may be analyzed to determine the cause of the deviation and the valve shown to be operating acceptably.

(d) Valve operability based upon analysis shall have the results of the analysis recorded in the record of tests (see [ISTC-9120](#)).

(e) Before returning a repaired or replacement valve to service, a test demonstrating satisfactory operation shall be performed.

ISTC-5120 Motor-Operated Valves. Active MOVs shall meet the requirements of [Division 1, Mandatory Appendix III](#).

ISTC-5130 Pneumatically Operated Valves. Active AOVs shall meet the requirements of [Division 1, Mandatory Appendix IV](#).

ISTC-5140 Hydraulically Operated Valves

ISTC-5141 Valve Stroke Testing

(a) Active valves shall have their stroke times measured when exercised in accordance with [ISTC-3500](#).

(b) The limiting value(s) of full-stroke time of each valve shall be specified by the Owner.

(c) The stroke time of all valves shall be measured to at least the nearest second.

(d) Any abnormality or erratic action shall be recorded (see [ISTC-9120](#)), and an evaluation shall be made regarding need for corrective action.

ISTC-5142 Stroke Test Acceptance Criteria. Test results shall be compared to reference values established in accordance with [ISTC-3300](#), [ISTC-3310](#), or [ISTC-3320](#).

(a) Valves with reference stroke times of greater than 10 sec shall exhibit no more than $\pm 25\%$ change in stroke time when compared to the reference value.

(b) Valves with reference stroke times of less than or equal to 10 sec shall exhibit no more than $\pm 50\%$ change in stroke time when compared to the reference value.

(c) Valves that stroke in less than 2 sec may be exempted from (b). In such cases the maximum limiting stroke time shall be 2 sec.

ISTC-5143 Stroke Test Corrective Action

(a) If a valve fails to exhibit the required change of obturator position or exceeds the limiting values of full-stroke time [see [ISTC-5141\(b\)](#)], the valve shall be immediately declared inoperable.

(b) Valves with measured stroke times that do not meet the acceptance criteria of [ISTC-5142](#) shall be immediately retested or declared inoperable. If the valve is retested and the second set of data also does not meet the acceptance criteria, the data shall be analyzed within 96 hr to verify that the new stroke time represents acceptable valve operation, or the valve shall be declared inoperable. If the second set of data meets the acceptance criteria, the cause of the initial deviation shall be analyzed and the results documented in the record of tests (see [ISTC-9120](#)).

(c) Valves declared inoperable may be repaired, replaced, or the data may be analyzed to determine the cause of the deviation and the valve shown to be operating acceptably.

(d) Valve operability based upon analysis shall have the results of the analysis recorded in the record of tests (see [ISTC-9120](#)).

(e) Before returning a repaired or replacement valve to service, a test demonstrating satisfactory operation shall be performed.

ISTC-5150 Solenoid-Operated Valves

ISTC-5151 Valve Stroke Testing

(a) Active valves shall have their stroke times measured when exercised in accordance with [ISTC-3500](#).

(b) The limiting value(s) of full-stroke time of each valve shall be specified by the Owner.

(c) Stroke time shall be measured to at least the nearest second.

(d) Any abnormality or erratic action shall be recorded (see [ISTC-9120](#)), and an evaluation shall be made regarding need for corrective action.

ISTC-5152 Stroke Test Acceptance Criteria. Test results shall be compared to reference values established in accordance with [ISTC-3300](#), [ISTC-3310](#), or [ISTC-3320](#).

(a) Valves with reference stroke times of greater than 10 sec shall exhibit no more than $\pm 25\%$ change in stroke time when compared to the reference value.

(b) Valves with reference stroke times of less than or equal to 10 sec shall exhibit no more than $\pm 50\%$ change in stroke time when compared to the reference value.

(c) Valves that stroke in less than 2 sec may be exempted from (b). In such cases the maximum limiting stroke time shall be 2 sec.

ISTC-5153 Stroke Test Corrective Action

(a) If a valve fails to exhibit the required change of obturator position or exceeds the limiting values of full-stroke time [see [ISTC-5151\(b\)](#)], the valve shall be immediately declared inoperable.

(b) Valves with measured stroke times that do not meet the acceptance criteria of [ISTC-5152](#) shall be immediately retested or declared inoperable. If the valve is retested and the second set of data also does not meet the acceptance criteria, the data shall be analyzed within 96 hr to verify that the new stroke time represents acceptable valve operation, or the valve shall be declared inoperable. If the second set of data meets the acceptance criteria, the cause of the initial deviation shall be analyzed and the results documented in the record of tests (see [ISTC-9120](#)).

(c) Valves declared inoperable may be repaired, replaced, or the data may be analyzed to determine the cause of the deviation and the valve shown to be operating acceptably.

(d) Valve operability based upon analysis shall have the results of the analysis recorded in the record of tests (see [ISTC-9120](#)).

(e) Before returning a repaired or replacement valve to service, a test demonstrating satisfactory operation shall be performed.

ISTC-5200 Other Valves

ISTC-5210 Manually Operated Valves. Valve testing shall be in accordance with [ISTC-3500](#). If a valve fails to exhibit the required change of obturator position, the valve shall be immediately declared inoperable. Valves equipped with remote position indication shall be tested in accordance with [ISTC-3700](#).

ISTC-5220 Check Valves**(22) ISTC-5221 Valve Obturator Movement**

(a) The necessary valve obturator movement during exercise testing shall be demonstrated by performing both an open and a close test.

(1) Check valves that have a safety function in both the open and close directions shall be exercised by initiating flow and observing that the obturator has traveled to either the full open position or the position required to perform its intended function(s) (see [ISTA-1100](#)), and verify that on cessation or reversal of flow, the obturator has traveled to the seat.

(2) Check valves that have a safety function in only the open direction shall be exercised by initiating flow and observing that the obturator has traveled to either the full open position or the position required to perform its intended function(s) (see [ISTA-1100](#)), and verify closure.

(3) Check valves that have a safety function in only the close direction shall be exercised by initiating flow and observing that the obturator has traveled at least the partially open position,³ and verify that on cessation or reversal of flow, the obturator has traveled to the seat.

Observations shall be made by observing a direct indicator (e.g., a position-indicating device) or by other positive means (e.g., changes in system pressure, flow rate, level, temperature, seat leakage, testing, or nonintrusive testing results).

(b) In lieu of the test methods in (a), a mechanical exerciser may be used to exercise the valve to the open and/or closed position. If a mechanical exerciser is used, the force(s) or torque(s) required to move the obturator and fulfill its safety function(s) shall meet the acceptance criteria specified by the Owner.⁴

(1) Exercise test(s) shall detect a missing obturator, sticking (closed or open), binding (throughout obturator movement), and the loss or movement of any weight(s). Both an open and close test may not be required.

(2) Acceptance criteria shall consider the specific design, application, and historical performance.

(3) If impracticable to detect a missing obturator or the loss or movement of any weight(s) using a mechanical exerciser, other positive means may be used [e.g., seat leakage tests and visual observations to detect obturator loss and the loss or movement of external weight(s), respectively].

(c) If the test methods in (a) and (b) are impractical for certain check valves, or if sufficient flow cannot be achieved or verified, a sample disassembly examination program shall be used to verify valve obturator movement. If maintenance is performed on one of these valves that could affect its performance, the postmaintenance testing shall be conducted in accordance with (c)(4).

The sample disassembly examination program shall group check valves of similar design, application, and service condition and require a periodic examination of one valve from each group. The details and bases of the sampling program shall be documented and recorded in the test plan (see [ISTC-9200](#)).

(1) Grouping⁵ of check valves for the sample disassembly examination program shall be technically justified and shall consider, as a minimum,⁶ valve manufacturer, design, service, size, materials of construction, and orientation.

(2) During the disassembly process, the full-stroke motion of the obturator shall be verified. Full-stroke motion of the obturator shall be reverified immediately prior to completing reassembly. Check valves⁷ that have their obturator disturbed before full-stroke motion is verified shall be examined to determine if a condition exists that could prevent full opening or reclosure of the obturator.

(3) At least one valve from each group shall be disassembled and examined at each refueling outage; all valves in each group shall be disassembled and examined at least once every 8 yr.

(4) Before return to service, valves that were disassembled for examination or that received maintenance that could affect their performance, shall be exercised full- or part-stroke, if practicable, with flow in accordance with [ISTC-3520](#).⁷ Those valves shall also be tested for other requirements (e.g., closure verification or leak rate testing) before returning them to service.

ISTC-5222 Condition-Monitoring Program. As an alternative to the testing or examination requirements of [ISTC-3510](#), [ISTC-3520](#), [ISTC-3530](#), [ISTC-3550](#), and [ISTC-5221](#), the Owner may establish a condition-

⁵ Maintenance and modification history should be considered in the grouping process.

⁶ Valve grouping should also consider potential flow instabilities, required degree of disassembly, and the need for tolerance or critical dimension checks.

⁷ Examples are spring-loaded lift check valves, or check valves with the obturator supported from the bonnet.

³ The partially open position should correspond to the normal or expected system flow.

⁴ If practicable, the force(s) or torque(s) required to move the obturator and fulfill any function should be evaluated to detect abnormality or erratic action for corrective action.

monitoring program. The purpose of this program is both to improve valve performance⁸ and to optimize testing, examination, and preventive maintenance (PM) activities⁹ in order to maintain the continued acceptable performance of a select group of check valves. The Owner may implement this program on a valve or a group of similar valves. The program shall be implemented in accordance with [Division 1, Mandatory Appendix II](#). If the condition-monitoring program for a valve or valve group is discontinued, then the requirements of this Subsection shall apply.

ISTC-5223 Series Valves in Pairs.¹⁰ If two check valves are in a series configuration without provisions to verify individual reverse flow closure (e.g., keepfill pressurization valves) and the plant safety analysis assumes closure of either valve (but not both), the valve pair may be operationally tested closed as a unit.

If the plant safety analysis assumes that a specific valve or both valves of the pair close to perform the safety function(s), the required valve(s) shall be tested to demonstrate individual valve closure.

ISTC-5224 Corrective Action. If a check valve fails to exhibit the required change of obturator position, it shall be declared inoperable. A retest showing acceptable performance shall be run following any required corrective action before the valve is returned to service.

Check valves in a sample disassembly program that are not capable of full-stroke movement (i.e., due to binding) or have failed or have unacceptably degraded valve internals, shall have the cause of failure analyzed and the condition corrected. Other check valves in the sample group that may also be affected by this failure mechanism shall be examined or tested during the same refueling outage

⁸ Examples of candidates for improved valve performance are check valves that

- (a) have an unusually high failure rate during inservice testing or operations
- (b) cannot be exercised under normal operating conditions or during shutdown
- (c) exhibit unusual, abnormal, or unexpected behavior during exercising or operation; or
- (d) the Owner elects to monitor for improved valve performance.

⁹ Examples of candidates for optimization of testing, examination, and preventive maintenance (PM) activities are check valves with documented acceptable performance that

- (a) have had their performance improved under the condition-monitoring program
- (b) cannot be exercised or are not readily exercised during normal operating conditions or during shutdown
- (c) can only be disassembled and examined, or
- (d) the Owner elects to optimize all of the associated activities of the valve group in a consolidated program.

¹⁰ [ISTC-5223](#) is only applicable to pre-2000 plants whose construction permit was issued January 1, 2000, or earlier.

to determine the condition of internal components and their ability to function.¹¹

Series valve pairs tested as a unit in accordance with [ISTC-5223](#) that fail to prevent reverse flow shall be declared inoperable, and both valves shall be either repaired or replaced.

ISTC-5230 Vacuum Breaker Valves. Vacuum breakers shall meet the applicable inservice test requirements of [Division 1, Mandatory Appendix I](#). (22)

ISTC-5240 Safety and Relief Valves. Safety and relief valves shall meet the inservice test requirements of [Division 1, Mandatory Appendix I](#).

ISTC-5250 Rupture Disks. Rupture disks shall meet the requirements for nonreclosing pressure relief devices of [Division 1, Mandatory Appendix I](#).

ISTC-5260 Explosively Actuated Valves

(a) A record of the service life of each charge in each valve shall be maintained. This record shall include the date of manufacture, batch number, installation date, and the date when service life expires based on manufacturer's recommendations. In no case shall the service life exceed 10 yr.

(b) Concurrent with the first test and at least once every 2 yr, the service life records of each valve shall be reviewed to verify that the service lives of the charges have not been exceeded and will not be exceeded before the next refueling. The Owner shall take appropriate actions to ensure charge service lives are not exceeded.

(c) At least 20% of the charges in explosively actuated valves shall be fired and replaced at least once every 2 yr. If a charge fails to fire, all charges with the same batch number shall be removed, discarded, and replaced with charges from a different batch.

(d) Replacement charges shall be from batches from which a sample charge shall have been tested satisfactorily and with a service life such that the requirements of (b) are met.

(e) In addition to the requirements specified in [Table ISTC-3500-1](#) (including requirements in [ISTC-5260](#)), post-2000 plants shall satisfy the following requirements for explosively actuated valves after commencement of commercial operation:

(1) At least once every 2 yr, each valve shall undergo visual examination of external surfaces and internal surfaces and parts.

(-a) Visual examination shall include documentation of the presence of fluids or other contaminants.

¹¹ An evaluation should be made to determine if there are valves outside of the sampling group that could be affected by the failure mechanism. Valves that are determined to be directly affected by the failure mechanism should be examined or tested.

(-b) Any identified fluids or other contaminants within the internal mechanism that could potentially interfere with the function of the valve shall be removed, and their presence shall be evaluated to determine the impact on the operational readiness of the valve and its actuator.

(-c) This examination shall include verification of the initial operating position of the internal actuating mechanism.

(-d) Proper operation of remote position indicators shall be confirmed.

(2) At least once every 2 yr, one valve of each size shall be disassembled for internal examination of the valve and actuator.

(-a) This examination will verify the operational readiness of the valve assembly by evaluating the internal components for their operational functionality, ensuring the integrity of individual components, and removing any foreign material, fluid, or corrosion in accordance with the Owner's examination procedures.

(-b) All valves shall be disassembled for internal examination at least once every 10 yr.

(3) For the valves selected in the test sample for (c), the operational readiness of the actuation logic and associated electrical circuits must be verified for each sampled valve following removal of its charge. This verification must include confirmation that sufficient electrical parameters (voltage, current, resistance) are available for each actuation circuit.

(4) For the valves selected in the test sample for (e), the sampling must select at least one explosively actuated valve from each redundant safety train every 2 yr. Each sampled pyrotechnic charge shall be tested in the valve or a qualified test fixture to confirm the capability of the charge to provide the necessary motive force to operate the valve to perform its intended function without damage to the valve body or connected piping.

(5) Corrective action shall be taken in accordance with the Owner's corrective action requirements to resolve any deficiencies identified.

(-a) during examinations with postmaintenance testing conducted in accordance with [ISTC-3100\(d\)](#)

(-b) in the capability of a pyrotechnic charge in accordance with [ISTC-3100\(d\)](#) or

(-c) in the actuation logic or associated electrical circuits

(6) If deficiencies are identified that would prevent specified operation, the valve shall be declared inoperable in accordance with the Owner's requirements. Deficiencies shall be addressed for other explosively actuated valves, such as by internal examination or pyrotechnic

charge and circuitry testing, as applicable, with appropriate actions based on those findings. Postmaintenance testing shall be conducted in accordance with [ISTC-3100\(d\)](#).

ISTC-6000 MONITORING, ANALYSIS, AND EVALUATION

To be provided at a later date.

ISTC-7000 TO BE PROVIDED AT A LATER DATE

ISTC-8000 TO BE PROVIDED AT A LATER DATE

ISTC-9000 RECORDS AND REPORTS

ISTC-9100 Records

ISTC-9110 Valve Records. The Owner shall maintain a record that shall include the following for each valve covered by this Subsection:

(a) the manufacturer and manufacturer's model and serial or other unique identification number

(b) a copy or summary of the manufacturer's acceptance test report if available

(c) preservice test results

(d) limiting value of full-stroke time specified in [ISTC-5113\(b\)](#), [ISTC-5141\(b\)](#), and [ISTC-5151\(b\)](#)

ISTC-9120 Record of Tests. See [ISTA-9230](#).

ISTC-9130 Record of Corrective Action. See [ISTA-9240](#).

ISTC-9200 Test Plans

In addition to the requirements of [ISTA-3110](#), the Owner shall maintain a record of test plans that shall include the following:

(a) category of each valve

(b) justification for deferral of stroke testing in accordance with [ISTC-3520](#)

(c) details and bases of the check valve sample disassembly examination program, such as grouping characteristics, frequency, and justification for not performing an exercise test to at least a partially open position after reassembly or periodic exercising in accordance with [ISTC-3520](#)

(d) bases for testing series check valve pairs as a unit in accordance with [ISTC-5223](#)

(e) valves that have no test requirements need not be included in test and examination plans

Subsection ISTD

Preservice and Inservice Requirements for Dynamic Restraints (Snubbers) in Water-Cooled Reactor Nuclear Power Plants

ISTD-1000 INTRODUCTION

ISTD-1100 Applicability

The requirements of this Subsection apply to certain dynamic restraints (snubbers, pin to pin, inclusive).

ISTD-1110 Exclusions. Examination of support structures and attachments is outside the scope of this Code, except for examinations required for evaluation in accordance with ISTD-1800.¹

ISTD-1400 Owner's Responsibility

It is the Owner's responsibility to meet all applicable requirements of Subsection ISTA and

(a) make available design and operating information necessary for the performance of the examination and testing program. Nonmandatory Appendix C contains a list of typical information that may be useful.

(b) identify and maintain a list of each snubber to be examined, tested, and included in service life monitoring in accordance with the rules of this Subsection.

(c) specify acceptance criteria for examination and testing.

(d) identify affected systems, structures, and components in accordance with ISTD-1800 and ISTD-4100 when the requirements of those paragraphs are applicable.

ISTD-1500 Snubber Maintenance or Repair

Snubber repair activities shall be performed in accordance with the ASME Boiler and Pressure Vessel Code (ASME BPVC), Section XI, as applicable.

ISTD-1510 Maintenance or Repair Before Examination or Testing. Snubbers shall not be adjusted, maintained, or repaired before an examination or test specifically to meet the examination or test requirements.

ISTD-1520 Post-Maintenance or Repair Examination and Testing. Snubbers that are maintained or repaired by removing or adjusting a snubber part that can affect the results of tests required by ISTD-5120 shall be tested in

¹ Examination requirements for support structures and attachments can be found in ASME Boiler and Pressure Vessel Code (ASME BPVC), Section XI.

accordance with the applicable requirements of ISTD-5120 before returning to service. Additionally, the requirements of ISTD-4110 shall be met. The requirements selected shall ensure that the parameters that may have been affected are verified to be acceptable by suitable examination and tests.²

ISTD-1600 Snubber Modification and Replacement

Snubber repair and replacement activities shall be performed in accordance with ASME BPVC, Section XI, as applicable.

ISTD-1610 Suitability. Replacement or modified snubber(s) shall have a proven suitability for the application and environment.

ISTD-1620 Examination and Testing. Replacement or modified snubbers shall be examined and tested in accordance with written procedures. The applicable requirements of ISTD-4100, ISTD-4200, ISTD-5200, and ISTD-5500 shall be included in these procedures. The requirements selected shall ensure that the criteria of ISTD-4110, ISTD-4230, and ISTD-5210 can be satisfied.

ISTD-1700 Deletions of Unacceptable Snubbers

Snubbers may be deleted from the plant based on analysis of the affected piping system. When an unacceptable snubber is deleted, the deleted snubber shall nevertheless be considered in its respective examination population, examination category, or failure mode group (FMG) for determining the corrective action.

ISTD-1750 Transient Dynamic Event. If an unanticipated transient dynamic event that may affect snubber operational readiness occurs and is identified outside the scope and performance of ISTD-4200 or ISTD-5200, then the affected snubbers and systems

² Examples of parts and activities that can affect the test results of ISTD-5120 are as follows:

- (a) mechanical or hydraulic snubber internal moving parts
- (b) hydraulic snubber internal seals (i.e., where bypass can affect test results)
- (c) activities that can permit air to be entrapped in the main cylinder or the control valve of a hydraulic snubber
- (d) hydraulic control valve adjustment

shall be reviewed and any appropriate corrective action taken. Any action so taken shall be considered independent of the requirements of [ISTD-4200](#) and [ISTD-5200](#).

ISTD-1800 Evaluation of Affected Systems, Structures, and Components

When a snubber is determined to be unacceptable, it is the owner's responsibility to identify the extent to which any systems, structures, or components may be affected by the unacceptable condition. An evaluation shall be performed to determine potential effects and any required corrective actions.

ISTD-2000 DEFINITIONS

The following list of definitions is provided to ensure a uniform understanding of selected terms as used in this Subsection.

activation: the change of condition from passive to active, in which the snubber resists rapid displacement of the attached pipe or component.

application-induced failures: failures resulting from environmental conditions or application of the snubber for which it has not been designed or qualified.

defined test plan group (DTPG): a population of snubbers from which samples are selected for testing.

design or manufacturing failure: failures resulting from a potential defect in manufacturing or design that give cause to suspect other similar snubbers. This includes failures of any snubber that fails to withstand the environment or application for which it was designed.

diagnostic testing: testing to determine the cause or mechanism associated with failure, degradation, or performance anomaly of a snubber.

drag force: the force that will sustain low-velocity snubber movement without activation throughout the working range of the snubber stroke.

failure mode group (FMG): a group of snubbers that have failed and those other snubbers that have similar potential for similar failure.

fuel cycle: time period beginning with the start of the reactor until the completion of the next refuel outage and subsequent restart.

hydraulic snubbers: dynamic restraint devices in which load is transmitted through a hydraulic fluid.

inaccessible snubbers: snubbers that are in a high radiation area or other conditions that would render it impractical for the snubbers to be examined/tested under normal plant operating conditions without exposing plant personnel to undue hazards.

maintenance, repair, and installation-induced failures: failures that result from damage during maintenance, repair, or installation activities, the nature of which causes other snubbers to be suspect.

mechanical snubbers: dynamic restraint devices in which load is transmitted entirely through mechanical components.

normal operating conditions: operating conditions during reactor startup, operating at power, hot standby, reactor cooldown, and cold shutdown.

operating temperature: the temperature of the environment surrounding a snubber at its installed plant location during the phase of plant operation for which the snubber is required.

operational readiness testing: measurement of the parameters that verify snubber operational readiness.

release rate: the rate of the axial snubber movement under a specified load after activation of the snubber takes place.

replacement snubber: any snubber other than the snubber immediately previously installed at a given location.

service life: the period of time a snubber is expected to meet the operational readiness requirements at its installed location without maintenance.

service life monitoring: the ongoing actions necessary to provide reasonable assurance a snubber will continue to meet operational readiness requirements. These actions address the reevaluation of initial predicted service life values and typically include applicable items such as

- (a) use of test and visual examination results
- (b) failure or degradation cause analysis
- (c) manufacturer's recommendations
- (d) maintenance practices
- (e) evaluation of environmental factors corresponding to a snubber location

service life population: those snubbers for which the same service life has been established.

successful test campaign: campaign completed without having to test the entire defined test plan group (DTPG) population.

swing clearance: the movement envelope within which the snubber must operate without restriction, from the cold installed position to the hot operating position.

test campaign: the series of actions required to complete the testing of DTPG samples per [ISTD-5200](#), [ISTD-5300](#), and [ISTD-5400](#), as applicable.

test interval: the period between completed test campaigns for a given DTPG.

test temperature: the temperature of the environment surrounding the snubber at the time of the test.

transient dynamic event failure: inability of a snubber to perform its intended function due to an unanticipated transient dynamic event.

unacceptable snubbers: snubbers that do not meet examination or testing requirements.

unanticipated transient dynamic event: any unforeseen or unanalyzed event, such as (but not limited to) a steam hammer, water hammer, void collapse, or seismic event greater than design basis.

unexplained failure: failure for which the cause has not been determined.

ISTD-3000 GENERAL REQUIREMENTS

ISTD-3100 General Examination Requirements

The following requirements apply to both the preservice and inservice examination programs.

ISTD-3110 Examination Boundary. The examination boundaries shall include the snubber assembly from pin to pin, inclusive.

ISTD-3120 Visual Examination. Snubbers shall be visually examined as specified in [ISTD-4000](#).

ISTD-3200 General Testing Requirements

The following requirements apply to both the preservice and inservice testing programs.

ISTD-3210 Operational Readiness Testing Loads. Snubbers shall be tested at a load sufficient to verify the test parameters specified in [ISTD-5100](#), [ISTD-5200](#), and [ISTD-5300](#), or [ISTD-5400](#) and [ISTD-5500](#). Testing at less than rated load must be correlated to test parameters at rated load.

ISTD-3220 Test Correction Factors. This Subsection recognizes that there may be differences between the installed operating conditions and the conditions under which a snubber is tested. In such cases, correction factors shall be established and test results shall be correlated to operating conditions, as appropriate.

ISTD-3230 Snubber Test Parameters and Methods. Guidelines for establishing snubber functional test methods are given in [Division 1, Nonmandatory Appendix H](#), Test Parameters and Methods.

ISTD-3240 Test Acceptance Criteria. The Owner shall establish and document test acceptance criteria for each applicable preservice and inservice test parameter specified in [ISTD-5120](#) and [ISTD-5210](#). Snubbers not meeting the established criteria shall be considered unacceptable in accordance with [ISTD-5320](#) and [ISTD-5420](#). Criteria shall be established prior to initiation of a test campaign and shall not be revised for the duration of that test campaign. However, criteria that is based upon specific

design factors (fluid type, valve models, part numbers, etc.) may be adjusted for newly identified design differences within a population when the changed criteria can be shown to be more appropriate for the specific snubbers involved.

ISTD-3300 General Service-Life Monitoring Requirements

Service life of snubbers shall be established and monitored per [ISTD-6000](#).

ISTD-4000 SPECIFIC EXAMINATION REQUIREMENTS

ISTD-4100 Preservice Examination

ISTD-4110 Preservice Examination Requirements. An initial preservice examination shall be performed on all snubbers prior to or during initial plant startup. For snubbers placed in new or modified systems, preservice examinations shall be performed prior to declaring the affected systems, structures, or components to be operable.

For operating plants implementing [Subsection ISTD](#), these requirements are not applicable if preservice examinations have previously been performed.

If a new snubber location is added to an existing piping system and determined to not require thermal movement or swing clearance verification per [ISTD-4130](#) through [ISTD-4133](#), it shall still require preservice examination in accordance with [ISTD-4110](#) at a minimum.

Typical items to be considered are listed in [Division 1, Nonmandatory Appendix B](#). The initial preservice examination shall, as a minimum, verify the following:

(a) No visible signs of damage or impaired operational readiness exist as a result of storage, handling, or installation.

(b) The snubber load rating, location, orientation, position setting, and configuration (e.g., attachments and extensions) are in accordance with design drawings and specifications. Installation records (based on physical examinations) of verification that the snubbers were installed according to the design drawings and specifications shall be acceptable in meeting this requirement.

(c) Adequate swing clearance is provided to allow snubber movement.

(d) If applicable, fluid is at the recommended level, and fluid is not leaking from the snubber system.

(e) Structural connections, such as pins, bearings, studs, fasteners, lock nuts, tabs, wire, and cotter pins, are installed correctly.

ISTD-4120 Reexamination. If the period between the preservice examination and initial system preoperational test exceeds 6 months, reexamination shall be performed in accordance with [ISTD-4110\(a\)](#), [ISTD-4110\(d\)](#), and [ISTD-4110\(e\)](#). This reexamination may be accomplished in conjunction with [ISTD-4130](#).

ISTD-4130 Preservice Thermal Movement Examination Requirements. Snubber thermal movement shall be verified as indicated in ISTD-4131 through ISTD-4133. For operating plants, the requirements of ISTD-4130 through ISTD-4133 are not applicable for replacement, repaired, or modified snubbers.

ISTD-4131 Incremental Movement Verification. During system heatup and cooldown at temperature plateaus specified by the Owner, record the thermal movement. Verify that the snubber movement during the thermal movement examination is within the design-specified range. Any discrepancies or inconsistencies shall be evaluated to determine the movement acceptability before proceeding to the next specified plateau.

ISTD-4132 Swing Clearance. Verify that swing clearance exists at specified heatup and cooldown plateaus.

ISTD-4133 Total Movement Verification. The total thermal movement from cold to hot at full operating temperature shall be recorded. This value may be measured directly if maximum operating temperature was attained, or it may be extrapolated from lower temperature readings. The cold or hot position setting shall be evaluated and adjusted if necessary, to ensure adequate snubber clearance from fully extended or retracted positions.

ISTD-4140 Preservice Examination Corrective Action. Snubbers that are installed incorrectly or otherwise fail to meet the requirements of ISTD-4110 shall be installed correctly, adjusted, repaired, or replaced. The installation-corrected, adjusted, repaired, or replacement snubber shall be examined in accordance with, and shall meet the requirements of ISTD-4110. Also, replacement snubbers shall meet the requirements of ISTD-5120.

(22) ISTD-4200 Inservice Examination

Snubbers shall be visually examined on the required schedule and evaluated to determine their operational readiness. The inservice intervals represent the maximum time between examinations for any individual snubber. Examinations may be performed at any time during the interval, but any snubber that exceeds this time between examinations shall be classified as unacceptable until such time as an acceptable examination or test in accordance with ISTD-4240 is completed.

ISTD-4210 Method and Objective. Inservice examination shall be a visual examination to identify physical damage, leakage, corrosion, or degradation that may have been caused by environmental exposure or operating conditions. External characteristics that may indicate operational readiness of the snubber shall be examined. An examination checklist shall be used. Typical items are listed in Division 1, Nonmandatory Appendix B.

ISTD-4220 Snubber Categorization

(a) All of the snubbers shall be categorized as one population for examination or they may be categorized as accessible and inaccessible populations.

(b) The decision to categorize the snubbers as one population or as separate populations may be made during or after the examination.

(c) If combining accessible and inaccessible populations into one population, the shorter interval shall be used for subsequent examination.

ISTD-4230 Visual Examination Requirements. Snubber installations shall meet all of the requirements of ISTD-4231 through ISTD-4233.

ISTD-4231 Restrained Movement. Snubbers shall be installed so they are capable of restraining movement when activated. Examinations shall include observations for the following and the conditions shall be evaluated when found:

(a) loose fasteners, or members that are corroded or deformed

(b) disconnected components or other conditions that might interfere with the proper restraint of movement

Snubbers evaluated to be incapable of restraining movement shall be classified unacceptable.

ISTD-4232 Thermal Movement. Snubber installations shall not restrain thermal movement to an extent that unacceptable stresses could develop in the snubber, the pipe, or other equipment that the snubber is designed to protect or restrain. This requirement is satisfied if no indication of binding, misalignment, or deformation of the snubber is observed.

ISTD-4233 Design-Specific Characteristics. Snubbers shall be free of defects that may be generic to particular designs as may be detected by visual examination. For example, fluid supply or content for hydraulic snubbers shall be observed. An observation that the fluid level is equal to or greater than the minimum specified amount that is sufficient for actuation at its operating extension is considered to satisfy this requirement. If the fluid is less than the minimum amount, the installation shall be identified as unacceptable, unless a test establishes that the performance of the snubber is within specified limits. Tests shall be performed in accordance with ISTD-5210.

ISTD-4234 Examination Prior to Maintenance or Testing. All snubbers shall be examined in accordance with the requirements of ISTD-4210 through ISTD-4240 prior to conducting any maintenance, stroking, or testing, and prior to removal, for any reason, from their installed location. (22)

ISTD-4240 Operational Readiness Test Evaluation. A snubber that requires further evaluation or is classified as unacceptable during inservice examination may be tested in accordance with the requirements of ISTD-5210.

Results that satisfy the operational readiness test criteria of [ISTD-5210](#) shall be used to accept the snubber, provided the test demonstrates that the unacceptable condition did not affect operational readiness.

ISTD-4250 Inservice Examination Intervals

ISTD-4251 Initial Examination Interval. The initial examination interval of snubbers shall begin no sooner than 2 months after attaining 5% reactor power operation and shall be completed by the end of first refueling outage. The initial interval shall not extend longer than 24 months after attaining 5% reactor power operation.

(22) ISTD-4252 Subsequent Examination Intervals

(a) Subsequent examination intervals shall begin at the end of the previous examination interval.

(b) Intervals prior to the completion of the second refueling outage shall not exceed one fuel cycle in duration.

(c) The duration of examination intervals following the completion of the second refueling outage shall be in accordance with [Table ISTD-4252-1](#). Examples of the application of [Table ISTD-4252-1](#) are provided in [Division 1, Nonmandatory Appendix G](#).

(d) When examinations have been performed after the first refueling outage in accordance with a schedule requirement other than those in [Table ISTD-4252-1](#), the interval preceding the most recently completed examination shall be used as the previous interval for the first application of [Table ISTD-4252-1](#).

(e) Snubbers determined to be unacceptable based on the visual examination acceptance criteria at any time during the interval shall be counted in determining the subsequent examination interval in accordance with [Table ISTD-4252-1](#), regardless of the means of discovery. This shall include, for example, all unacceptable snubbers found during scheduled visual examinations; observed during walkdowns, maintenance, testing, snubber replacement, reservoir fluid level monitoring, transient dynamic event or water hammer evaluations; or service life monitoring activities. The total number of unacceptable snubbers shall be applied when using [Table ISTD-4252-1](#) and [ISTD-4253](#).

(22) ISTD-4253 Additional Requirements for 10-yr Interval. All snubbers within the scope of [Subsection ISTD](#) may be examined and evaluated at least once every 10 yr in accordance with [Table ISTD-4252-1](#), [Note \(7\)](#) provided the following requirements are satisfied:

(a) If at any time during an examination interval the cumulative number of unacceptable snubbers per [ISTD-4252\(e\)](#) exceeds the applicable value from [Table ISTD-4252-1](#), Column B, the current examination interval shall end, and all remaining examinations must be completed within the current fuel cycle. The duration

of the subsequent examination interval shall be reduced to the 48-month maximum cycle examination interval used prior to implementing the 10-yr interval. The beginning of the subsequent fuel cycle shall be the starting date for the new examination interval.

(b) No alternatives to [ISTD-5200](#) testing requirements that allow for extended test intervals shall be used in conjunction with examination intervals that exceed a nominal value of 48 months.

ISTD-4260 Inservice Examination Sample Size. Inservice examination of snubbers required by [ISTD-4251](#) and [ISTD-4252](#) shall include all snubbers based either on the whole population or on the accessibility categories, as established according to the provisions of [ISTD-4220](#).

ISTD-4270 Inservice Examination Failure Evaluation. Snubbers that do not meet examination requirements of [ISTD-4230](#) shall be evaluated to determine the cause of the unacceptability.

ISTD-4280 Inservice Examination Corrective Action. Unacceptable snubbers shall be adjusted, repaired, modified, or replaced. Additional action regarding the examination interval shall be taken as indicated in [Table ISTD-4252-1](#).

ISTD-5000 SPECIFIC TESTING REQUIREMENTS

ISTD-5100 Preservice Operational Readiness Testing

ISTD-5110 General. Preservice operational readiness testing shall be performed on all snubbers. Testing may be performed at the manufacturer's facility.

ISTD-5120 Test Parameters. Tests shall verify the following:

(a) activation is within the specified range of velocity or acceleration in tension and in compression. For snubbers that do not have an activation function, this parameter is not applicable.

(b) release rate, when applicable, is within the specified range in tension and in compression. For units specifically required not to displace under continuous load, ability of the snubber to withstand load without displacement.

(c) for mechanical snubbers, drag force is within specified limits in tension and in compression.

(d) for hydraulic snubbers, if required to verify proper assembly, drag force is within specified limits in tension and in compression.

ISTD-5130 Preservice Operational Readiness Testing Failures Corrective Action

ISTD-5131 Test Failure Evaluations. Snubbers that fail the preservice operational readiness test shall be evaluated for the cause(s) of failure(s).

Table ISTD-4252-1
Visual Examination Table

(22)

Population or Category [Note (1)]	Number of Unacceptable Snubbers		
	Column A for Extended Interval [Notes (2), (3)]	Column B for Interval Same as Previous [Notes (2), (4), (5)]	Column C for Interval Reduction to $\frac{2}{3}$ [Notes (2), (5), (6)]
1	0	0	1
80	0	0	2
100	0	1	4
150	0	3	8
200	2	5	13
300	5	12	25
400	8	18	36
500	12	24	48
750	20	40	78
≥1000	29	56	109

NOTES:

- (1) Reference ISTD-4252(e) for considerations regarding unacceptable snubbers. Interpolation between population or category sizes and the number of unacceptable snubbers is permissible. The next lower integer shall be used when interpolation results in a fraction.
- (2) The basic interval shall be the length of the normal fuel cycle up to 24 months. The examination interval may be as great as twice, the same, or as small as fractions of the previous interval as required by Notes (3) through (6). The following grace periods may be applied to the resulting intervals:
 - (a) For intervals less than 2 yr, completion of the examinations may be extended by up to 25% of the interval.
 - (b) For intervals greater than or equal to 2 yr, completion of the examinations may be extended by up to 6 months except as noted in Note (7).
- The examination interval grace period noted above shall not be used to extend an examination period for an additional fuel cycle.
- (3) For intervals up to and including 24 months, if the number of unacceptable snubbers is equal to or less than the number in Column A, then the next examination interval may be increased to twice the previous examination interval, with a maximum nominal interval of 48 months and limitations as defined in Note (2) above.
- (4) If the number of unacceptable snubbers is equal to or less than the number in Column B, then the next visual examination may be conducted at the same interval as the previous interval.
- (5) For extended intervals up to 48 months, if the number of unacceptable snubbers exceeds the number in Column B, but is equal to or less than the number in Column C, then the next examination interval shall be decreased to two-thirds of the previous examination interval or, in accordance with the interpolation between Columns B and C, in proportion to the exact number of unacceptable snubbers.
- (6) For extended intervals up to 48 months, if the number of unacceptable snubbers exceeds the number in Column C, then the next examination interval shall be decreased to two-thirds of the previous interval.
- (7) If the previous examination was performed at the maximum interval of two fuel cycles as described in Note (3) and the number of unacceptable snubbers is equal to or less than the number in Column A, the subsequent examination interval may be extended to a maximum of 10 yr provided all requirements of ISTD-4253 are met. No grace period extension is applicable to extend any visual examination beyond 10 yr.

ISTD-5132 Design Deficiency. If a design deficiency in a snubber is found, it shall be corrected by changing the design or specification, or by other appropriate means.

ISTD-5133 Other Deficiencies. Other deficiencies shall be resolved by adjustment, modification, repair, replacement, or other appropriate means.

ISTD-5134 Retest Requirements. Adjusted, modified, repaired, or replacement snubbers shall be tested to meet the requirements of [ISTD-5120](#).

ISTD-5200 Inservice Operational Readiness Testing

Snubbers shall be tested for operational readiness during each fuel cycle as defined in [ISTD-5240](#). Test campaigns are required to be in accordance with a specified sampling plan as defined in [ISTD-5260](#). Testing may be performed during normal system operation, or during system or plant outages. The Owner's administrative procedures shall govern removing snubbers from operable system(s).

ISTD-5210 Test Parameters. Snubber operational readiness tests shall verify the following:

(a) activation is within the specified range of velocity or acceleration in tension and in compression. For snubbers that do not have an activation function, this parameter is not applicable.

(b) release rate, when applicable, is within the specified range in tension and in compression. For units specifically required not to displace under continuous load, ability of the snubber to withstand load without displacement.

(c) for mechanical snubbers, drag force is within specified limits, in tension and in compression.

ISTD-5220 Test Methods

ISTD-5221 Test as Found. Snubbers shall be tested in their as-found condition regarding the parameters to be tested to the fullest extent practicable.

ISTD-5222 Restriction. Test methods shall not alter the condition of a snubber to the extent that the results do not represent the as-found snubber condition.

ISTD-5223 In-Place Test. Snubbers may be tested in their installed location by using Owner-approved test methods and equipment.

ISTD-5224 Bench Test. Snubbers may be removed and bench tested in accordance with Owner-approved procedures. After reinstallation, the applicable requirements of [ISTD-4200](#) shall be met. Also, the position setting shall be verified.

ISTD-5225 Subcomponent Test. When snubber size, test equipment limitations, or inaccessibility prevents use of methods in [ISTD-5223](#) and [ISTD-5224](#), snubber subcomponents that control the parameters to be verified

shall be examined and tested in accordance with Owner-approved test methods. Reassembly shall be in accordance with approved procedures that include the applicable requirements of [ISTD-4200](#). Service life monitoring requirements are specified in [ISTD-6400](#).

ISTD-5226 Correlation of Indirect Measurements.

When test methods are used that either measure parameters indirectly, or measure parameters other than those specified, the results shall be correlated with specified parameters through established methods.

ISTD-5227 Parallel and Multiple Installations. Each snubber in a parallel or multiple installation shall be identified and counted individually.

ISTD-5228 Fractional Sample Sizes. Fractional sample sizes shall be rounded up to the next integer.

ISTD-5240 Test Frequency. An inservice test campaign shall be conducted every fuel cycle. Testing associated with each test campaign shall begin no earlier than 92 days before a scheduled refueling outage and shall be completed prior to completion of that refueling outage.

ISTD-5250 Defined Test Plan Group (DTPG)

ISTD-5251 DTPGs General Requirement. The DTPGs shall include all snubbers except replacement snubbers and snubbers repaired or adjusted as a result of not meeting the examination acceptance requirements of [ISTD-4200](#). These snubbers shall be exempt for the concurrent test interval.

ISTD-5252 DTPG Alternatives. Except as required by [ISTD-5253](#), the total snubber population may be considered one DTPG, or alternatively, differences in design, application, size, or type may be considered in establishing DTPGs. DTPGs shall not be changed after initiating a test campaign.

ISTD-5253 Additional DTPG Requirements for Pressurized Water Reactors (PWRs). Snubbers attached to the steam generator and snubbers attached to the reactor coolant pump shall be at least one, separate DTPG.

ISTD-5260 Testing Sample Plans

ISTD-5261 Sample Plans. The snubbers of each DTPG shall be tested using either of the following:

(a) the 10% testing sample plan

(b) the 37 testing sample plan

[Division 1, Nonmandatory Appendix D](#) includes a comparison of sample plans. Snubber testing plans are presented in flowchart form in [Division 1, Nonmandatory Appendix E](#).

ISTD-5262 Plan Selection. A test plan shall be selected for each DTPG before the scheduled test campaign begins.

ISTD-5263 Plan Application. The test plan selected for a DTPG shall be used throughout the test campaign for that DTPG and any failure mode group (FMG) that is derived from it.

ISTD-5270 Continued Testing. For unacceptable snubber(s), the additional testing shall continue in the DTPG or FMG per [ISTD-5330](#) or [ISTD-5430](#).

ISTD-5271 Test Failure Evaluation. Snubbers that do not meet test requirements specified in [ISTD-5210](#) shall be evaluated to determine the cause of the failure.

(a) The evaluation shall include review of information related to other unacceptable snubbers found during that test campaign.

(b) The evaluation results should be used, if applicable, to determine FMGs to which snubbers may be assigned. Evaluation information may be used to assign previously unexplained unacceptable snubbers to an appropriate FMG.

ISTD-5272 FMGs. Snubbers found unacceptable according to operational readiness test requirements may be assigned to FMGs. FMGs shall include all unacceptable snubbers with the same failure mode and all other snubbers with similar potential for similar failure. The following FMGs should be considered:

- (a) design or manufacturing
- (b) application induced
- (c) maintenance, repair, or installation
- (d) transient dynamic event

ISTD-5273 FMG Boundaries

(a) When snubbers have been tested as a part of DTPG test requirements and found to be unacceptable, and evaluation establishes an FMG based on the failure of certain snubbers, the number of those unacceptable snubbers shall be used in determining testing in the FMG in accordance with [ISTD-5320](#) and [ISTD-5330](#), or [ISTD-5420](#) and [ISTD-5430](#). However, those snubbers shall be counted only in the value of N of [ISTD-5331\(a\)](#) or [ISTD-5431\(a\)](#) as completed tests in the DTPG.

(b) When snubbers have been found to be acceptable when tested as part of DTPG test requirements and subsequent evaluation establishes an FMG that would include those snubbers, those snubbers shall not be counted in the value of N_F in [ISTD-5331\(b\)](#) or [ISTD-5431\(b\)](#) when counting FMG tests.

(c) An FMG shall remain as defined until corrective action is complete.

ISTD-5274 Snubbers in More Than One FMG. When a snubber is assigned to more than one FMG, it shall be counted in each of those FMGs and shall be included in corrective action for each of those FMGs.

ISTD-5275 Additional FMG Review. After the requirements of [ISTD-5250](#), [ISTD-5260](#), [ISTD-5270](#), [ISTD-5320](#), and [ISTD-5420](#) are satisfied for a DTPG, any separate and additional FMG review or testing does not require additional tests in the DTPG.

ISTD-5280 Corrective Action. Unacceptable snubbers shall be adjusted, repaired, modified, or replaced. The provisions of [ISTD-1620](#) and [ISTD-1700](#) also apply. Snubbers that do not meet the test requirements of [ISTD-5210](#) shall be tested in accordance with [ISTD-5320](#) or [ISTD-5420](#), as applicable.

ISTD-5300 The 10% Testing Sample

ISTD-5310 The 10% Testing Sample Plan, Sample Size, and Composition

ISTD-5311 Initial Sample Size and Composition. The initial sample shall be 10% of the DTPG, composed according to either (a) or (b).

(a) As practicable, the sample shall include representation from the DTPG based on the significant features (i.e., the various designs, configurations, operating environments, sizes, and capacities) and based on the ratio of the number of snubbers of each significant feature, to the total number of snubbers in the DTPG. Selection of the representative snubbers shall be random.

(b) The sample shall be generally representative as specified in (a), but may also be selected from snubbers concurrently scheduled for seal replacement or other similar activity related to service life monitoring. The snubbers shall be tested on a generally rotational basis to coincide with the service life monitoring activity.

ISTD-5312 Additional Sample Size. When additional samples are required by [ISTD-5320](#), they shall be at least one-half the size of the initial sample from that DTPG.

ISTD-5313 Additional DTPG Sample Composition. When an unacceptable snubber has not been assigned to an FMG, the additional sample required by [ISTD-5320](#) shall be taken from the DTPG. As practicable, the additional sample shall include the following:

- (a) snubbers of the same manufacturer's design
- (b) snubbers immediately adjacent to those found unacceptable
- (c) snubbers from the same piping system
- (d) snubbers from other piping systems that have similar operating conditions such as temperature, humidity, vibration, and radiation
- (e) snubbers that are previously untested

ISTD-5314 FMG Sample Composition. When samples from an FMG are required, they shall be selected randomly from untested snubbers in the FMG.

ISTD-5320 The 10% Testing Sample Plan Additional Testing

ISTD-5321 DTPG Testing. When an applicable FMG has not been established, the number of unacceptable snubbers shall determine the additional testing samples in accordance with [ISTD-5312](#) and [ISTD-5330](#).

ISTD-5323 FMG Testing. The following actions shall apply for FMG testing:

(a) *Transient Dynamic Event FMG.* The operational readiness of all snubbers in this FMG shall be evaluated by stroking or testing. All snubbers in this FMG that are determined to be operationally ready by stroking remain eligible for selection and tests for other appropriate FMGs and the DTPG in accordance with [ISTD-5313](#) and [ISTD-5314](#). However, snubbers that are determined to be operationally ready by testing shall not be eligible for such tests.

(b) *Other FMGs.* Tests in each FMG shall be based both on the number of unacceptable snubbers found in the DTPG and determined by the evaluation of [ISTD-5271](#) to be appropriate for establishing the FMG, and on the number of unacceptable snubbers subsequently found in the FMG. Testing shall continue until the mathematical expression of [ISTD-5331\(b\)](#) is satisfied or all snubbers in the FMG have been tested. Failures in an FMG shall require additional tests within the FMG unless the failure evaluation indicates that an additional and separate FMG is appropriate for additional tests from the DTPG.

ISTD-5330 The 10% Testing Sample Plan Completion. The snubbers of each DTPG and FMG shall be tested as required. Testing is complete when the mathematical expressions of [ISTD-5331](#) are satisfied, or all snubbers in the DTPG or FMG have been tested.

ISTD-5331 Testing Plan Mathematical Expression. Testing shall satisfy the mathematical expressions as follows:

(a) for each DTPG

$$N \geq A + C(B)$$

where

A = initial sample size

= $0.1n$ (rounded up to the next integer)

B = $A/2$ (rounded up to the next integer)

C = total number of unacceptable snubbers found in the DTPG (excluding those counted for FMG tests)

N = total number of snubbers tested that were selected from the DTPG

n = number of snubbers in the DTPG

(b) for each FMG

$$N_F \geq C_F(B)$$

where

C_F = total number of unacceptable snubbers in the FMG, plus those found in the DTPG and used to establish the FMG

N_F = all snubbers selected and tested from the FMG after the FMG was established from the DTPG

ISTD-5400 The 37 Testing Sample Plan**ISTD-5410 The 37 Testing Sample Plan, Sample Size, and Composition**

ISTD-5411 Initial Sample Size and Composition. An initial sample of 37 snubbers shall be selected randomly from each 37 plan DTPG.

ISTD-5412 Additional Sample Size. When additional samples are required by [ISTD-5420](#), the samples shall be either 18 or 19 snubbers to satisfy the requirement of [ISTD-5431](#).

ISTD-5413 Additional Sample Selection. Additional samples, if required, shall be selected randomly from the remaining population of the DTPG, or from untested snubbers of the FMG as applicable.

ISTD-5420 The 37 Testing Sample Plan Additional Testing

ISTD-5421 DTPG Testing. When an applicable FMG has not been established, the number of unacceptable snubbers shall determine additional samples in accordance with [ISTD-5412](#). The additional samples shall be selected randomly from the remaining untested snubbers of the DTPG.

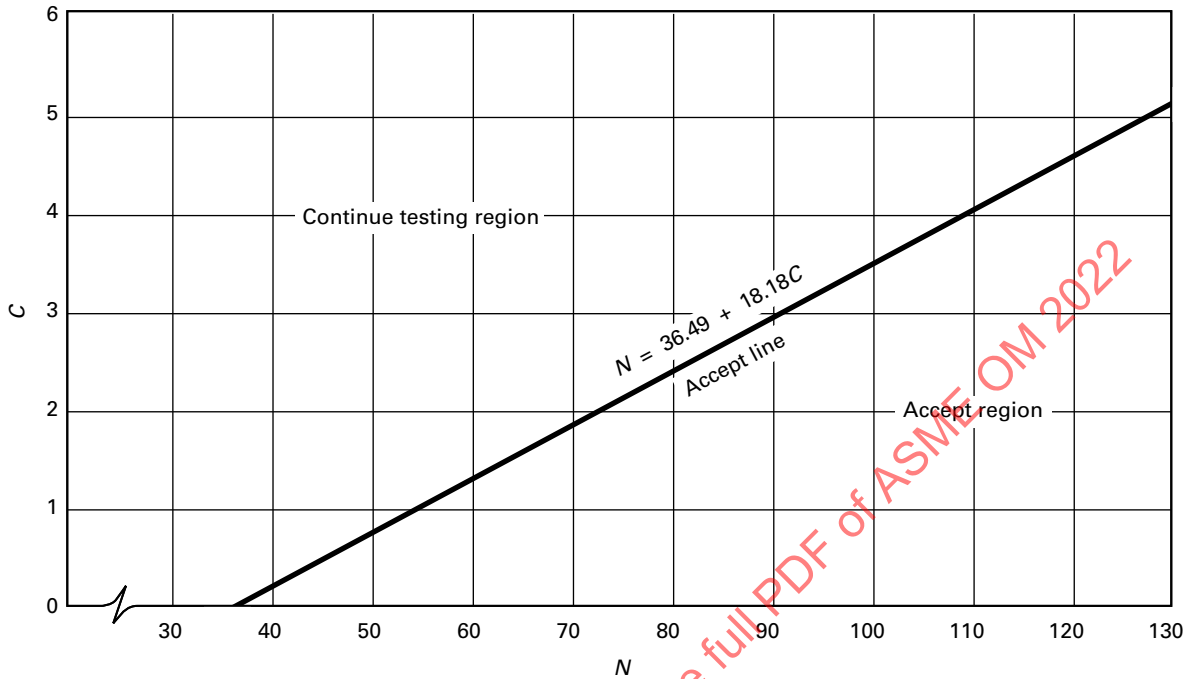
ISTD-5423 FMG Testing. The following actions shall apply for FMG testing:

(a) *Transient Dynamic Event FMG.* The operational readiness of all snubbers in this FMG shall be evaluated by stroking or testing. All snubbers in this FMG that are determined to be operationally ready by stroking remain eligible for selection and tests for other appropriate FMGs and the DTPG in accordance with [ISTD-5413](#). However, snubbers that are determined to be operationally ready by testing shall not be eligible for such tests.

(b) *Other FMGs.* Tests in each FMG shall be based both on the number of unacceptable snubbers found in the DTPG and determined by the evaluation of [ISTD-5271](#) to be appropriate for establishing the FMG, and on the number of unacceptable snubbers subsequently found in the FMG. Testing shall continue until the mathematical expression of [ISTD-5431\(b\)](#) is satisfied or all snubbers in the FMG have been tested. Failures in an FMG shall require additional tests within the FMG unless the failure evaluation indicates that an additional and separate FMG is appropriate for additional tests from the DTPG.

(c) *Additional DTPG Testing Requirements.* A supplemental sample shall be tested from the applicable DTPG for each FMG established to satisfy

Figure ISTD-5431-1
The 37 Testing Sample Plan



ISTD-5431(a). Failures in a supplemental sample require additional tests in the DTPG unless the failure evaluation indicates that an additional FMG is appropriate.

ISTD-5430 The 37 Testing Sample Plan Completion.

The snubbers of each DTPG and FMG shall be tested as required. Testing is complete when the mathematical expressions of **ISTD-5431** are satisfied, or all snubbers in the DTPG or FMG have been tested.

ISTD-5431 Testing Plan Mathematical Expressions.

Testing shall satisfy the mathematical expressions as follows:

(a) for each DTPG

$$N \geq 36.49 + 18.18C \text{ (Figure ISTD-5431-1)}$$

where

C = total number of unacceptable snubbers found in the DTPG (excluding those counted in FMG tests), plus one for each FMG established

N = total number of snubbers tested that were selected from the DTPG

(b) for each FMG requiring additional tests

$$N_F \geq 18.18C_F$$

where

C_F = total number of unacceptable snubbers in the FMG, plus those found in the DTPG and used to establish the FMG

N_F = all snubbers selected and tested after the FMG was established from DTPG

ISTD-5500 Retests of Previously Unacceptable Snubbers

Snubbers placed in the same location as snubbers that failed during the previous test campaign shall be retested at the time of the subsequent test campaign unless the cause of the failure is clearly established and corrected so as to preclude reoccurrence. Any retest in accordance with this paragraph shall not be considered a part of the test campaign sample selection requirements of **ISTD-5200**, **ISTD-5300**, or **ISTD-5400**. In addition, failures found by these retests shall not require additional testing in accordance with **ISTD-5320** or **ISTD-5420**, but shall be evaluated for appropriate corrective action.

ISTD-6000 SERVICE LIFE MONITORING REQUIREMENTS

ISTD-6100 Initial Service Life

Initial predicted snubber service life shall be established based on the manufacturer's recommendation and review of actual and expected service conditions

corresponding to a snubber location. Typical factors affecting service life are addressed in [Division 1, Nonmandatory Appendix F](#).

ISTD-6200 Service Life Reevaluation

The service life for each installed snubber shall be reevaluated at least once each fuel cycle for continued acceptability and adjusted if required based on the review of new information related to service life where applicable. Examples of such new information include test results; changes to system operating conditions, environment, or previous service conditions; visual examination results; seal life evaluations; failure and degradation cause analyses; and miscellaneous activities, such as manual exercising, regreasing, seal replacement, and fluid addition.

Based on the results of this review, the service life of each snubber, at its installed location, shall be increased, decreased, or left unchanged.

Completion of this reevaluation shall be documented in accordance with [ISTD-9500](#).

If any snubber's reevaluated service life will be exceeded before the next scheduled system or plant outage, one of the following actions shall be taken prior to the end of that snubber's service life:

(a) The snubber shall be replaced with a snubber for which the service life will not be exceeded before the next scheduled system or plant outage.

(b) Technical justification for ensuring continued operational readiness shall be documented for extending the established service life until the time when the snubber can be reconditioned or replaced.

(c) The snubber shall be reconditioned such that its service life is extended to or beyond the next scheduled system or plant outage.

ISTD-6300 Cause Determination

Causes for any snubber failures (regardless of the means or time of discovery) shall be determined, documented, and considered in establishing or reestablishing service life.

ISTD-6400 Additional Monitoring Requirements for Snubbers That Are Tested Without Applying a Load to the Snubber Piston Rod

The service life evaluation, for hydraulic snubbers that are tested without applying a load to the snubber piston rod, shall consider the results of the following requirements:

(a) monitoring the particulate, viscosity, and moisture content of one or more samples of hydraulic fluid from the main cylinder of the snubber. This may be accomplished using snubbers of the same design in a similar or more severe environment.

(b) monitoring of piston seal, piston rod seal, and cylinder seal integrity. If seal integrity is monitored by pressurization, pressures less than the snubber's rated load pressure may be used. Minimum pressure allowed shall be specified by the Owner.

ISTD-6500 Testing for Service Life Monitoring Purposes

If testing is conducted specifically for service life monitoring purposes, the results of such testing do not require testing of additional snubbers in accordance with [ISTD-5320](#) or [ISTD-5420](#), but shall be evaluated for appropriate corrective action.

ISTD-6600 Review of Operational Readiness Test Data (22)

All inservice test data shall be evaluated for indications of snubber degradation or other anomalies. This includes a review of test traces, where available. The results of this evaluation shall be used

(a) to identify snubbers that are subject to progressive degradation

(b) to identify severe operating environments not previously identified

ISTD-6700 Examination During Assembly (22)

Snubbers and snubber parts that are disassembled (during failure evaluation, refurbishment, etc.) shall be examined for indications of degradation and severe operating environments.

ISTD-7000 TO BE PROVIDED AT A LATER DATE

ISTD-8000 TO BE PROVIDED AT A LATER DATE

ISTD-9000 RECORDS AND REPORTS

ISTD-9100 Snubber Records

The Owner shall maintain records that shall include the following for each snubber covered by this Subsection:

(a) the name of the manufacturer, and the manufacturer's model and serial numbers or other unique identification number

(b) a copy or summary of the manufacturer's acceptance test report, preservice test report, or current inservice test report

ISTD-9200 Test Plans

In addition to the applicable requirements of [ISTA-3110](#), the Owner shall maintain a record of examination plans (accessible or inaccessible snubbers) and test plans (entire population or DTPGs) for all the snubbers.

ISTD-9300 Record of Tests

(a) In addition to the requirements of [ISTA-9230](#), the results of examination and test data shall include the manufacturer's model number, serial number, type, and unique location identification or the Owner's identification of the snubber, as applicable.

(b) Records of predicted service life of all snubbers and service life reevaluations shall be maintained.

ISTD-9400 Record of Corrective Action

See [ISTA-9240](#).

ISTD-9500 Service Life Records

The following records shall be maintained for each installed snubber:

- (a) current service life
- (b) basis for current service life
- (c) initial installation date at current location
- (d) test, examination, and maintenance history (including any failure/degradation history)
- (e) corrective actions required to address service life issues

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Subsection ISTE

Risk-Informed Inservice Testing of Components in Water-Cooled Reactor Nuclear Power Plants

ISTE-1000 INTRODUCTION

ISTE-1100 Applicability

The requirements of this Subsection apply to certain pumps and valves included in a risk-informed inservice test program¹ for dividing the population of pumps and valves, as identified in the IST Program Plan, into high safety significant component (HSSC) and low safety significant component (LSSC) categories.

ISTE-1200 Alternative

This Subsection specifies alternative IST requirements for certain pumps and valves, as identified in the IST Plan.

ISTE-1300 General

All the requirements of [Subsections ISTA, ISTB, and ISTC](#) apply, except as identified in this Subsection. Valves for which test requirements are not specified in [ISTE-5000](#) shall be tested in accordance with [Subsection ISTC](#).

(22) ISTE-2000 SUPPLEMENTAL DEFINITIONS

The following are provided to ensure a uniform understanding of selected terms used in this Subsection.

aggregate risk: the risk due to programmatic changes in the IST program (test method effectiveness and/or testing interval) as measured by CDF or LERF.

basic event: an event in a fault tree model that requires no further development, because appropriate limit of resolution has been reached.

common cause failure (CCF): a failure of two or more components during a short period of time as a result of a single shared cause.

core damage: uncovering and heatup of the reactor core to the point at which prolonged oxidation and severe fuel damage is anticipated and involving enough of the core to cause a significant release.

core damage frequency (CDF): expected number of core damage events per unit of time. (A Level 1 PRA identifies accident sequences that can lead to core damage, calculates the frequency of each sequence, and sums those frequencies to obtain CDF.)

decision criteria: the quantitative and qualitative factors that influence a decision. These include both quantitative screening criteria (for PRA model) and the evaluation of other qualitative (or deterministic) factors that influence the results of an application.

defense in depth: considerations in a risk informed-inservice testing (RI-IST) program that are maintained by consideration of CCF modes, consideration of appropriate failure modes, consideration of multiple risk metrics including CDF and LERF, consideration of test strategies, and assessment of aggregate risk.

Expert Panel: the team of experts responsible for categorizing affected components as either HSSCs or LSSCs.

figures-of-merit: the quantitative value, obtained from a PRA analysis, used to evaluate the results of an application (e.g., CDF or LERF).

Fussell-Vesely (F-V) Importance Measure: for a specified basic event, Fussell-Vesely importance is the fractional contribution to the total of the selected figure of merit for all accident sequences containing that basic event.

high safety significant components (HSSCs): components that have been designated as more important to plant safety by a blended process of PRA risk ranking and Plant Expert Panel evaluation.

importance measure: a mathematical expression that defines a quantity of interest. The most common importance measures are F-V and RAW.

initiating event: a perturbation to the steady-state operation of the plant that challenges plant control and safety systems whose failure could potentially lead to core damage.

large early release: the rapid, unmitigated release of airborne fission products from the containment to the environment occurring before the effective implementation of off-site emergency response and protective actions such there is a potential for early health effects.

¹ Component safety categorization methodology and process may result in additional components being included in the IST program, since there may be components that are required for safe shutdown and accident mitigation that are not ASME Boiler and Pressure Vessel Code (ASME BPVC) Classes 1, 2, and 3.

large early release frequency (LERF): expected number of large early releases per unit of time. (A Level 2 PRA identifies accident sequences that can lead to radioactivity release, calculates the frequency of each sequence, and sums these frequencies to obtain LERF.)

living PRA: a plant-specific PRA that is maintained up to date, such that plant modifications, plant operation changes (including procedure changes), component performance, and other technical information significantly affecting the model are reflected in the model.

low safety significant components (LSSCs): components that have been designated as less important to plant safety by a blended process of PRA insights and Plant Expert Panel evaluation.

PRA failure rate: the conditional probability of failure of a component on the next demand (for standby component) or in the next hour of operation (for operating component), given that it has not already failed.

probabilistic risk assessment (PRA): a qualitative and quantitative assessment of the risk associated with plant operation and maintenance that is measured in terms of frequency of occurrence of risk metrics, such as core damage or a radioactive material release and its effects on the health of the public [also referred to as a probabilistic safety assessment (PSA)]. In general the scope of a PRA is divided into three categories: Level 1, Level 2, and Level 3. A Level 1 maps from initiating events to plant damage states, including their aggregate, core damage. Level 2 includes Level 1 mapping from initiating events to release categories (source term). A Level 3 includes Level 2 and uses the source term of Level 2 to quantify sequences, the most common of which are health effects and property damage in terms of cost.

risk achievement worth (RAW): for a specified basic event, the increase in a selected figure of merit when an SSC is assumed to be unable to perform its function due to testing, maintenance, or failure. It is the ratio or interval of the figure of merit, evaluated with the SSC's basic event probability set to one, to the base case figure of merit.

risk significance: importance of plant components, based on their functions, using PRA methods only (i.e., without deterministic or other qualitative information as might be used by the Plant Expert Panel).

safety margin: considerations in an RI-IST Program shall be maintained by performance criteria for the components, Plant Expert Panel utilization, and monitoring/trending/analysis/evaluation.

safety significance: an item's contribution to plant risk using a blended process of PRA methods and Expert Panel evaluation.

testing effectiveness: the ability of a test to determine key performance attributes of a component without damaging the component or adversely affecting plant safety.

(Testing effectiveness can be determined by a type of test that is nondestructive, does not remove the component from service, identifies appropriate functional failure modes, detects precursors to malfunction; and predicts degradation leading to failure.)

truncation limits: the numerical cutoff value of probability or frequency below which results are not retained in quantitative PRA model or used in subsequent calculations (such limits can apply to accident sequences/cut sets, system level cut sets, and sequence/cut set database retention).

ISTE-3000 GENERAL REQUIREMENTS

ISTE-3100 Implementation

(22)

The requirements of this Subsection shall be implemented for all IST components of the same type. Component types are defined as

- (a) centrifugal pumps, including vertical line shaft pumps
- (b) positive displacement pumps
- (c) motor-operated valves (MOVs)
- (d) pneumatically operated valves (AOVs)
- (e) check valves

Other types of components [e.g., manual valves, solenoid valves, hydraulically operated valves (HOVs), pressure relief valves] shall be tested in accordance with the requirements of the applicable subsection.

ISTE-3200 Probabilistic Risk Assessment

ISTE-3210 Plant-Specific PRA. The Owner is responsible for demonstrating the technical adequacy of the PRA used as the basis to perform component risk ranking. PRA technical adequacy shall be assessed against ASME/ANS RA-S-2008² or a set of acceptance criteria that is endorsed by the regulatory agency having jurisdiction over the plant site.

ISTE-3220 Living PRA. The PRA shall be maintained up to date.

ISTE-3300 Integrated Decision Making

ISTE-3310 Plant Expert Panel. A Plant Expert Panel shall be designated to perform the blended safety evaluation of probabilistic and deterministic engineering information for each component.

ISTE-3320 Integrated Effects. Components can be affected by more than one risk-informed application (e.g., risk-informed inservice testing, risk-informed inservice inspection, graded quality assurance). Integrated effects of multiple risk-informed applications (including

² ASME/ANS RA-S-2008, with the RA-Sa-2009 Addenda, Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications.

risk-informed applications outside of the ASME scope) shall be evaluated.

ISTE-3330 Determination of HSSC and LSSC. The Plant Expert Panel shall evaluate each component and categorize it as HSSC or LSSC, using PRA quantitative information (if component is modeled) and engineering qualitative information (for both modeled and not modeled components).

ISTE-3400 Evaluation of Aggregate Risk

The aggregate risk impact of changes to the IST program shall be evaluated by the Owner (e.g., Plant Expert Panel). Decision criteria, quantitative evaluations, and qualitative assessments are a part of this aggregate risk impact evaluation.

ISTE-3500 Feedback and Corrective Actions

Feedback and corrective action processes are required elements of this Subsection as specified in ISTE-6200.

ISTE-4000 SPECIFIC COMPONENT CATEGORIZATION REQUIREMENTS

In addition to requirements of ISTE-3000, the following requirements apply to component categorization into HSSC and LSSC categories, and to an RI-IST program based on those categories.

ISTE-4100 Component Risk Categorization

This paragraph establishes requirements for separating components into HSSC or LSSC categories, performing PRA sensitivity studies to ensure that assumptions in the PRA are not masking the importance of a component, and determining how to treat components not modeled.

ISTE-4110 Appropriate Failure Modes. Component risk categorization shall be based on basic events that include failure modes representing functions addressed by inservice testing (e.g., pump failure to run, valve failure to open, common cause failure).

ISTE-4120 Importance Measures

(a) As a minimum, two importance measures, F-V and RAW, shall be calculated for those components modeled in the PRA.

(b) Importance measures should be evaluated for both CDF and LERF, if available.

ISTE-4130 Screening Criteria. For those components modeled in the PRA,

(a) a threshold value of F-V > 0.005 or lower based on either CDF or LERF should be initially considered as HSSC

(b) a threshold value of RAW > 2 based on either CDF or LERF should be initially considered as HSSC

ISTE-4140 Sensitivity Studies

(a) The following sensitivity studies shall be performed:

(1) *Data and Uncertainties.* Failure probabilities of components, within the PRA models for those IST components that have initially very high or very low values, shall be selectively increased and/or decreased to determine if the results are sensitive to changes in the failure data. If sensitivities are indicated, steps shall be taken to determine if uncertainty ranges can be reduced and to validate the failure probabilities included in the models.

(2) *Human Recovery Actions.* The PRA shall be requantified, and the F-V and RAW importance measures recalculated, after human actions modeled in the PRA, to recover from specific component failures, are adjusted in the models (e.g., the probability of successful recovery due to human intervention is adjusted by factor of 10).

(3) *Test and Maintenance Unavailabilities.* The PRA models shall be requantified with test and maintenance unavailabilities adjusted, and the importance measures recalculated.

(4) *LSSC Failure Rates.* Failure rates for components initially ranked LSSC shall be increased by a factor representing the upper bound (95%) of the failure rate and the PRA models requantified. The importance measures shall then be recalculated.

(5) *Truncation Limits.* If the PRA has not been quantified with a truncation limit 10^{-4} below the baseline PRA CDF, the PRA model shall be requantified with the truncation limit lowered to this value. The importance measures shall then be recalculated.

(6) *Common Cause.* Sensitivity analyses shall be used to determine the impact of increased or decreased common cause failure rates. Importance measures shall then be recalculated.

(b) The results of these sensitivity studies and any others that are performed shall be documented. In addition to the magnitude of the changes to the CDF or LERF, all insights obtained from the results shall be described.

The results and insights of these sensitivity studies shall be provided to the Plant Expert Panel for their consideration in the final categorization of the components.

ISTE-4150 Qualitative Assessments. Qualitative assessments shall be performed for all LSSCs, modeled and not modeled in the PRA, to determine whether there are other bases for categorizing IST components.

(a) The following qualitative assessments shall be performed:

(1) impact of initiating events (e.g., the impact of failure or degradation as it might result in an initiator, component contribution to initiating events represented by point estimates)

(2) potential consequences of shutdown (outage) conditions

(3) response to external initiating events (e.g., seismic, fire, high winds/tornadoes, flooding, etc.)

(4) impact of LERF, if not used in [ISTE-4120\(b\)](#)

(b) Qualitative assessments shall be performed for plant-specific design bases conditions and events not modeled in a PRA.

(c) Qualitative assessments shall consider the impacts upon the plant to

(1) prevent or mitigate accident conditions

(2) reach and/or maintain safe shutdown conditions

(3) preserve the reactor primary coolant pressure boundary integrity

(4) maintain containment integrity

(d) Qualitative assessments shall also consider

(1) safety function being satisfied by the component's operation

(2) level of redundancy existing at the plant to fulfill the component's function

(3) ability to recover from a failure of the component

(4) performance history of the component

(5) plant technical specifications requirements applicable to the component

(6) emergency operating procedure instructions that use the component(s)

(7) design and current licensing basis information relevant to RI-IST component function

(e) The cumulative impacts of combinations of component unavailability, which could impact an entire system (e.g., multi-train impacts) or critical safety function (e.g., multi-system impacts), shall also be considered.

(f) These qualitative assessments and the Plant Expert Panel's disposition of them shall be documented.

(g) These qualitative assessments shall be available to the Plant Expert Panel for their decision of component safety categorization.

ISTE-4160 Components Not Modeled. If the failure of an IST component(s) not modeled in the PRA is determined by the Plant Expert Panel to result in an increase in plant risk, consideration shall be given to updating the PRA model to incorporate the component(s) and then using the updated model to provide a quantified basis for categorization (either HSSC or LSSC). If the PRA model is not updated to incorporate this component(s), the basis for excluding the component(s) from the PRA shall be documented in the proceedings of the Plant Expert Panel.

ISTE-4200 Component Safety Categorization

This paragraph provides requirements for the Plant Expert Panel's review and evaluation process for categorizing IST components relative to their safety significance, using both deterministic and probabilistic insights.

ISTE-4210 Plant Expert Panel Utilization. The Plant Expert Panel shall blend deterministic and probabilistic information to classify IST components into HSSC or LSSC categories.

(a) *PRA Insights.* The results of PRA analyses shall be used by the Plant Expert Panel to help determine the safety significance of components within the scope of RI-IST and PRA programs. Information contained in PRAs relative to the role of components in mitigating or preventing core damage events or radiological release events shall be considered. The scope of the PRA and depth of probabilistic analyses shall be assessed, evaluated, and documented. As a minimum, the following shall be documented:

(1) the level of plant specific PRA analysis available for assessing the applicability of PRA information relative to IST programs. For example, written documentation shall describe the level of plant specific PRA analysis such as Level 1 PRA (assessment of core damage frequency) and/or Level 2 PRA (assessment of core damage frequency plus containment performance).

(2) scope of initiating events considered (internal, external, both).

(3) typical failure modes considered (e.g., hardware failures, testing/maintenance failures, common cause failures, and human errors).

(4) PRA scope for plant configurations (e.g., low power risk, shutdown risk, transition mode risk, at-power risk) reviewed relative to the applicability of PRA information and IST component function(s).

(b) *Deterministic Insights.* The Plant Expert Panel shall also consider deterministic factors when assessing the safety significance of components within the scope of IST programs (see [Division 1, Nonmandatory Appendix K](#) for a sample list of deterministic considerations).

ISTE-4220 Plant Expert Panel Requirements

(a) *Plant Procedure.* An approved plant procedure shall describe the process, including

(1) designated members and alternates

(2) designated chairperson and alternate

(3) quorum

(4) attendance records

(5) agendas

(6) motions for approval

(7) process for decision making

(8) documentation and resolution of differing opinions

(9) minutes

(10) implementation of feedback/corrective actions

(11) feedback to the PRA

(12) required training

(b) *Training.* The Plant Expert Panel shall be trained and indoctrinated by the Owner in the specific requirements to be used for this Subsection. Training and indoctrination shall include the application of risk analysis

methods and techniques used for this Subsection. At a minimum, the risk methods and techniques should include

(1) PRA fundamentals (e.g., PRA technical approach, PRA assumptions and limitations, failure probability, truncation limits, uncertainty)

(2) use of risk importance measures

(3) assessment of failure modes

(4) reliability versus availability

(5) risk thresholds

(6) expert judgment elicitation

Each of the aforementioned topics shall be covered in the indoctrination to the extent necessary to provide the Plant Expert Panel with a level of knowledge needed to adequately evaluate and approve the scope of the IST selections, using both probabilistic and deterministic information.

(c) *Expertise.* Member expertise levels shall be documented and maintained.

(d) *Membership*

(1) There shall be at least five experts designated as members of the Plant Expert Panel. Members may be experts in more than one field; however, excessive reliance on any one member's judgment shall be avoided.

(2) The chairperson shall be familiar with this Subsection and shall facilitate Plant Expert Panel activities, to ensure that the requirements of this Subsection are satisfied.

(3) Expertise in the following functions shall be represented on the Plant Expert Panel:

(-a) operation

(-b) safety analysis engineering

(-c) probabilistic risk assessment

(-d) ASME inservice testing

(4) Additional members of the Plant Expert Panel who have the following plant expertise may be selected:

(-a) systems performance

(-b) maintenance

(-c) licensing

(-d) component performance

(-e) quality assurance

(-f) design engineering

(5) Alternate members to the Plant Expert Panel may be designated on a temporary basis; however, vacancies in the Plant Expert Panel membership should be filled within a reasonable period of time. Alternate members must meet the same requirements as permanent members.

(6) Other plant or nuclear industry experts may be invited to attend some or all of the sessions of the Plant Expert Panel as visitors to provide observations, opinions, or recommendations.

ISTE-4230 Plant Expert Panel Decision Criteria. Plant Expert Panel decision criteria for categorizing components as HSSC and LSSC shall be documented.

ISTE-4240 Reconciliation. Decisions of the Plant Expert Panel shall be arrived at by consensus. Differing opinions shall be documented and resolved, if possible.

(a) If a resolution cannot be achieved concerning the safety significance classification of a component, then the component shall be classified HSSC.

(b) If components have a high initial ranking from the PRA (i.e., RAW > 2 or F-V > 0.005) but are ultimately ranked as LSSCs, the Plant Expert Panel decisions shall provide justification and shall be documented.

ISTE-4300 Testing Strategy Formulation

(a) Testing strategies for HSSCs and LSSCs shall be developed following the requirements specified in ISTE-5000.

(b) After testing strategies are developed, the planned changes (e.g., test frequency, testing effectiveness, and out-of-service duration) shall be provided for input to the evaluation of aggregate risk.

ISTE-4400 Evaluation of Aggregate Risk

ISTE-4410 Decision Criteria

(a) Appropriate decision criteria for aggregate risk effects shall be established and documented.

(b) Decision criteria shall be based on thresholds for aggregate risk limits using standard figures-of-merit (e.g., CDF, LERF). (Division 1, Nonmandatory Appendix L provides guidance.)

(2) Performance criteria used for other regulatory requirements may be taken into consideration when developing decision criteria for aggregate risk effects.

(b) Decision criteria may be determined both qualitatively and quantitatively.

ISTE-4420 Quantitative Assessment

(a) An aggregate risk evaluation shall be performed prior to implementation, as applicable, using the PRA.

(1) Quantitative attributes associated with this Subsection shall be considered and included in the quantitative evaluation, as appropriate, and within the scope of the PRA.

(2) Each applicable quantitative IST attribute shall be incorporated into the quantitative evaluation, as appropriate, until all proposed changes have been dispositioned (i.e., incorporated or not incorporated).

(3) Once all appropriate inputs have been incorporated, the PRA shall be rerun to assess the overall risk impact.

(4) Proposed IST program changes shall be assessed to determine compliance with approved decision criteria and to quantitatively determine if any adjustments or compensatory measures are warranted.

(b) Types of quantitative attributes that should be considered in the quantitative evaluation include changes in

- (1) testing frequency
- (2) out-of-service duration
- (3) failure rates
- (4) failure modes
- (5) common cause failure susceptibility
- (6) compensatory measures
- (7) testing scheme (staggered or simultaneous testing)

Compensatory measures include both those specifically incorporated into plant programs and those developed for specific situations. Management-directed compensatory measures should also be included in the quantitative assessment, as appropriate. Documented failure rates shall be used in the quantification process for IST component.

(c) Testing effectiveness shall be evaluated by periodic assessments or when new failure modes are identified that impact risk quantification.

(1) New failure modes shall be incorporated in accordance with risk management and corrective action programs into the quantitative evaluation, as appropriate.

(2) Changes resulting from programs that significantly affect the reliability or availability of components that perform important safety functions shall be assessed, and, if appropriate, incorporated into the PRA for requantification.

Such assessments may be performed in conjunction with the plant specific Maintenance Rule (10 CFR 50.65) requirements.

ISTE-4430 Qualitative Evaluation

(a) Aggregate risk effects shall be qualitatively evaluated (i.e., risk decreases as well as risk increases) for IST program changes (e.g., testing effectiveness).

(b) Pertinent performance indicators, industry programs, or other scrutable methods for establishing aggregate risk effects shall be identified and monitored.

(c) Feedback processes and corrective action programs as described in ISTE-6200 shall be considered in the evaluation of aggregate risk.

ISTE-4440 Defense in Depth. The IST aspects of defense in depth shall be maintained.

ISTE-4450 Safety Margins. The IST aspects of safety margin shall be maintained.

ISTE-4500 Inservice Testing Program

ISTE-4510 Maximum Testing Interval. The maximum testing interval shall be based on the more limiting of the following:

- (a) the results of the aggregate risk
- (b) performance history of the component

ISTE-4520 Implementation Schedule. A schedule shall be developed for implementing the testing strategies as specified in ISTE-5000.

ISTE-4530 Assessment of Aggregate Risk. Once the test schedule has been developed, the schedule shall be assessed against the assumptions of the aggregate risk evaluation.

ISTE-4540 Transition Plan. A transition plan shall be developed for each component type to ensure adequate information is collected to support justification of stepwise test interval extension up to and including the maximum allowable interval. Staggered test intervals may be used for implementing a stepwise test interval extension.

ISTE-5000 SPECIFIC TESTING REQUIREMENTS

ISTE-5100 Pumps

ISTE-5110 High Safety Significant Pump Testing. Pumps categorized as HSSCs shall meet all requirements of Subsections ISTA and ISTB or ISTF.

ISTE-5120 Low Safety Significant Pump Testing

ISTE-5121 Low Safety Significant Pump Testing — Pre-2000 Plants³

(a) Group A and Group B pumps categorized as LSSCs shall meet all the requirements of Subsections ISTA and ISTB, except that the testing requirements identified in this paragraph and in Table ISTE-5121-1 may be substituted for those in ISTB-3400 (Table ISTB-3400-1).

(b) All Group A and Group B LSSC pumps shall receive an initial Group A test conducted at the comprehensive pump flow rate as soon as practical and no later than the first refueling outage following implementation of the RI-IST Program.

(c) Thereafter, all Group A and Group B LSSC pumps shall be Group A tested at the comprehensive pump flow rate at least once every 5 yr or three refueling outages, whichever is longer.

ISTE-5122 Low Safety Significant Pump Testing — Post-2000 Plants⁴

(a) Pumps categorized as LSSCs shall meet all the requirements of Subsections ISTA and ISTF, except that the testing requirements identified in this paragraph and in Table ISTE-5121-1 may be substituted for those in ISTF-3400.

³ Pre-2000 plant: a nuclear power plant that was issued its construction permit by the applicable regulatory authority prior to January 1, 2000.

⁴ Post-2000 plant: a nuclear power plant that was issued (or will be issued) its construction permit, or combined license for construction and operation, by the applicable regulatory authority on or following January 1, 2000.

**Table ISTE-5121-1
LSSC Pump Testing**

Pump Group	Group A Test [Note (1)]	Group B Test	Comprehensive Test
Group A (routinely or continuously operated pumps)	6 months [Note (2)]	Not required	Not required
Group B (standby pumps)	2 yr	6 months [Note (2)]	Not required

NOTES:

- (1) This column also applies if using Subsection ISTF.
 (2) To meet vendor recommendations, pump operation may be required more frequently than the specified test frequency.

(b) All LSSC pumps shall receive an initial test conducted at the inservice test flow rate as soon as practical and no later than the first refueling outage following implementation of the RI-IST Program.

(c) Thereafter, the LSSC pumps shall be tested every 6 months in accordance with Subsection ISTF and within $\pm 20\%$ of pump design flow rate at least once every 5 yr or three refueling outages, whichever is longer.

ISTE-5130 Maximum Test Interval — Pre-2000 Plants. If the maximum test interval as determined from ISTE-4510 for a specific pump is more limiting than the interval of ISTE-5110 or ISTE-5120 (as applicable), the most limiting interval shall be used for that pump. A Group A or Group B test, as applicable, shall be performed to satisfy the increased test frequency requirements.

ISTE-5200 Check Valves

In lieu of meeting the inservice exercising test requirements for Category C check valves as specified in ISTE-3522, the following alternative may be applied.

ISTE-5210 High Safety Significant Check Valve Testing. HSSC check valves shall be placed in a condition-monitoring program and tested in accordance with Division 1, Mandatory Appendix II. The condition-monitoring program shall include identification and trending of attributes indicative of degradation that could lead to the occurrence of the failure mode(s) that resulted in HSSC categorization.

ISTE-5220 Low Safety Significant Check Valve Testing. LSSC check valves shall be tested in accordance with Subsection ISTC.

ISTE-5300 Motor-Operated Valve Assemblies

In lieu of the rules for preservice and inservice testing to assess the operational readiness of certain MOV assemblies in water-cooled reactor power plants in Subsection ISTC, HSSC and LSSC MOVs shall meet the re-

quirements of Division 1, Mandatory Appendix III, except as provided in ISTE-5320 below. The Leak Testing Requirements of ISTC 4.3 (1995 Edition with the 1996 and 1997 Addenda) or ISTE-3600 (1998 Edition and later) continue to apply, as applicable.

ISTE-5310 High Safety Significant MOVs. HSSC MOVs shall be tested in accordance with Division 1, Mandatory Appendix III, using established test frequencies and utilizing a mix of static and dynamic MOV performance testing.

ISTE-5320 Low Safety Significant MOVs. In lieu of meeting the inservice test frequency requirements of Division 1, Mandatory Appendix III, the following alternative rules may be applied:

(a) LSSC MOVs grouping shall be technically justified, but need not comply with all the requirements of Division 1, Mandatory Appendix III.

(b) LSSC MOVs shall be associated with an established group of other MOVs wherever possible. When a member of that group is tested, the test results shall be analyzed and evaluated in accordance with Division 1, Mandatory Appendix III and applied to all LSSCs associated with that group.

(c) LSSC MOVs that are not able to be associated with an established group, shall be inservice tested in accordance with Division 1, Mandatory Appendix III using an initial test frequency of three refueling cycles or 5 yr (whichever is longer) until sufficient data exists to determine a more appropriate test frequency.

(d) LSSC MOVs shall be inservice tested at least every 10 yr in accordance with Division 1, Mandatory Appendix III.

ISTE-5400 Pneumatically Operated Valves

ISTE-5410 High Safety Significant Pneumatically Operated Valve Assemblies Testing

(a) HSSC AOVs shall meet all the requirements of Subsections ISTA and ISTC, except as provided in (b).

(b) HSSC AOVs shall be tested in accordance with Division 1, Mandatory Appendix IV.

ISTE-5420 Low Safety Significant Pneumatically Operated Valve Assemblies Testing

(a) LSSC AOVs shall meet all the requirements of Subsections ISTA and ISTC, except as provided in (b).

(b) LSSC AOVs shall meet all the requirements of Division 1, Mandatory Appendix IV.

ISTE-5500 To Be Provided at a Later Date

ISTE-6000 MONITORING, ANALYSIS, AND EVALUATION

ISTE-6100 Performance Monitoring

ISTE-6110 HSSC Attribute Trending. For HSSCs, a set of attributes to be tested shall be established and compared to acceptance criteria in accordance with ISTE-5000, and a trending program shall be implemented for those testable attributes selected for monitoring.

ISTE-6120 LSSC Performance Trending. For LSSCs, the inservice testing specified in ISTE-5000 shall be supplemented by performance monitoring. The performance of the LSSCs shall be trended to ensure the component failure rates do not increase to unacceptable levels.

ISTE-6200 Feedback and Corrective Actions

ISTE-6210 Feedback

(a) A feedback process incorporating elements of both conditional and periodic feedback shall be established such that component performance information is directed to both the IST and PRA programs. Conditional feedback shall occur in a timely fashion following component failure. Periodic feedback shall be considered for maintenance of the PRA.

(b) Each program shall assimilate performance information to ensure the appropriate unavailability information is reflected in decision making.

(c) A feedback process shall be established so IST programmatic changes are directed to the PRA program.

(d) Feedback frequency should not exceed two refueling cycles.

ISTE-6220 Corrective Action. In addition to the requirements in the IST Code of Record with respect to corrective actions, a corrective action program shall be established that identifies and tracks to resolution all fail-

ures of similar types of components within an RI-IST Program incorporating risk insights, including evaluation of generic implications.

ISTE-6230 Component Safety Significance Recategorization. The component's operational readiness is not changed by recategorization.

ISTE-7000 TO BE PROVIDED AT A LATER DATE

ISTE-8000 TO BE PROVIDED AT A LATER DATE

ISTE-9000 RECORDS AND REPORTS

In addition to the requirements in the Code of Record with respect to records, the Plant Expert Panel and component records listed in ISTE-9100 and ISTE-9200, respectively, shall be maintained:

ISTE-9100 Plant Expert Panel Records

- (a) membership and attendance
- (b) member expertise representation and training per ISTE-4220(b)
- (c) member experience (years of experience in each of the expertise categories)
- (d) meeting agendas
- (e) meeting minutes
- (f) plant procedure

ISTE-9200 Component Records

- (a) risk significance based on PRA importance measures
- (b) additional PRA quantitative information
- (c) deterministic information
- (d) Plant Expert Panel categorization decisions of HSSC or LSSC
- (e) basis for the HSSC/LSSC decision

Subsection ISTF

Inservice Testing of Pumps in Water-Cooled Reactor Nuclear Power Plants — Post-2000 Plants¹

ISTF-1000 INTRODUCTION

ISTF-1100 Applicability

The requirements of this Subsection apply to certain centrifugal and positive displacement pumps that have an emergency power source.

ISTF-1200 Exclusions

The following are excluded from this Subsection:

- (a) drivers, except where the pump and driver form an integral unit and the pump bearings are in the driver
- (b) pumps that are supplied with emergency power solely for operating convenience
- (c) skid-mounted pumps that are tested as part of the major component and are justified by the Owner to be adequately tested

ISTF-1300 Owner's Responsibility

In addition to the requirements of [ISTA-1500](#), it is the Owner's responsibility to

- (a) include in both the pumps and plant design all necessary valving, instrumentation, test loops, required fluid inventory, or other provisions that are required to fully comply with the requirements of this Subsection. Testing capability shall be possible irrespective of plant mode.
- (b) identify each pump to be tested in accordance with the requirements of this Subsection.
- (c) establish an inservice test flow rate.
- (d) identify those pumps with specific design basis accident flow rates in the Owner's credited safety analysis for inclusion in a Pump Periodic Verification Test Program.

ISTF-2000 SUPPLEMENTAL DEFINITIONS

The following is provided to ensure a uniform understanding of selected terms used in this Subsection:

¹ *Post-2000 plant*: a nuclear power plant that was issued (or will be issued) its construction permit, or combined license for construction and operation, by the applicable regulatory authority on or following January 1, 2000.

baseline test: a test performed when a pump is new, or overhauled, to obtain thorough information for use in the evaluation of degradation in pump performance.

inservice test flow rate: the flow rate established by the Owner that is effective for detecting mechanical and hydraulic degradation during subsequent testing. The best efficiency point, system flow rates, pump periodic verification flow rate, and any other plant-specific flow rates shall be considered.

pump periodic verification test: a test that verifies a pump can meet the required (differential or discharge as applicable) pressure, at its highest design basis accident flow rate.²

vertical line shaft pump: a vertically suspended pump where the pump driver and pump element are connected by a line shaft within an enclosed column.

ISTF-3000 GENERAL TESTING REQUIREMENTS

The hydraulic and mechanical condition of a pump relative to a previous condition can be determined by attempting to duplicate by test a set of reference values. Deviations detected are symptoms of changes and, depending upon the degree of deviation, indicate need for further tests or corrective action.

The parameters to be measured during preservice and inservice testing are specified in [Table ISTF-3000-1](#).

ISTF-3100 Preservice Testing

During the preservice test period, or before implementing inservice testing, a baseline test shall be performed and an initial set of reference values established, in accordance with [ISTF-3300](#), for each pump required to be tested by this Subsection. Except as specified in [ISTF-3310](#), only one baseline test is required during the preservice test period for each pump. The baseline test shall be performed under conditions as near as practicable to those expected during subsequent inservice testing, in accordance with the requirements of the following:

- (a) centrifugal pump tests (except vertical line shaft centrifugal pumps) in accordance with [ISTF-5110](#)

² A pump may have several design basis accident operating points due to different system configurations or single vs. parallel pump operation.

Table ISTF-3000-1
Inservice Test Parameters

Quantity	Baseline Test	Inservice Test	Pump Periodic Verification Test [Note (1)]	Remarks
Speed, N	X	X	X	If variable speed
Differential pressure, ΔP	X	X	X	Centrifugal pumps, including vertical line shaft pumps
Discharge pressure, P	X	X	X	Positive displacement pumps
Flow rate, Q	X	X	X	...
Vibration	X	X	...	Measure either V_d or V_v
Displacement, V_d	...	...	...	Peak-to-peak
Velocity, V_v	...	...	...	Peak

NOTE: (1) Only required for those pumps identified in [ISTF-1300\(d\)](#).

(b) vertical line shaft centrifugal pump tests in accordance with [ISTF-5210](#)

(c) positive displacement pump tests in accordance with [ISTF-5310](#)

ISTF-3200 Inservice Testing

Inservice testing of a pump in accordance with this Subsection shall commence when the pump is required to be operable (see [ISTF-1100](#)). Inservice testing shall be performed in accordance with the requirements of the following paragraphs:

(a) centrifugal pump tests (except vertical line shaft centrifugal pumps) in accordance with [ISTF-5120](#)

(b) vertical line shaft centrifugal pump tests in accordance with [ISTF-5220](#)

(c) positive displacement pump (except reciprocating) tests in accordance with [ISTF-5320](#)

(d) reciprocating positive displacement pump tests in accordance with [ISTF-5320](#)

(22) ISTF-3300 Reference Values

Reference values for the pump inservice test shall be obtained as follows:

(a) Initial reference values shall be determined from the results of testing meeting the requirements of [ISTF-3100](#), Preservice Testing, or from the results of the first inservice test.

(b) New or additional reference values shall be established as required by [ISTF-3310](#) or [ISTF-3320](#), or [ISTF-6200\(c\)](#).

(c) Reference values shall be established only when the pump is known to be operating acceptably.

(d) Reference values shall be established at a point(s) of operation (reference point) readily duplicated during subsequent tests.

(e) Reference values shall be established at the inservice test flow rate.

(f) All subsequent test results shall be compared to these initial reference values or to new reference values established in accordance with [ISTF-3310](#) or [ISTF-3320](#), or [ISTF-6200\(c\)](#).

(g) Related conditions that can significantly influence the measurement or determination of the reference value shall be analyzed in accordance with [ISTF-6400](#).

(h) For smooth running pump measured vibration reference values less than 0.050 ips, the Owner may use 0.050 ips as the minimum reference value for one or more of the vibration points. In such cases, the minimum reference value of 0.050 ips shall be used to define acceptable pump performance in accordance with [ISTF-5000](#).

ISTF-3310 Effect of Pump Replacement, Repair, and Maintenance on Reference Values

ISTF-3311 Replacement and Major Maintenance.

Following replacement, major maintenance, or routine servicing (e.g., impeller replacement), such that the existing baseline test data and reference values do not represent the installed pump, the following shall be performed before declaring the pump operable:

(a) A baseline test shall be performed in accordance with [ISTF-5110](#), [ISTF-5210](#), or [ISTF-5310](#), as applicable.

(b) A new set of reference values shall be established in accordance with [ISTF-3300](#) from the results of the baseline test.

(c) Verification that the new reference values represent acceptable pump operation shall be placed in the record of tests (see [ISTF-9000](#)).

(d) Determine whether the pump periodic verification test is required.

ISTF-3312 Routine Maintenance and Repair. When a reference value or set of reference values may have been affected by repair or routine maintenance, other than that covered under [ISTF-3311](#), the following shall be performed before declaring the pump operable:

(a) An inservice test shall be performed and

(1) the previous reference values reconfirmed, or

(22)

Table ISTF-3510-1
Required Instrument Accuracy

Quantity	Baseline and Inservice Tests, %	Pump Periodic Verification Test, %
Pressure	$\pm \frac{1}{2}$	[Note (1)]
Flow rate	± 2	[Note (1)]
Speed	± 2	[Note (1)]
Vibration		
>4 Hz to 1,000 Hz	± 5	N/A
[Note (2)]		
1 Hz to 4 Hz	± 15	N/A
[Note (3)]		
Differential pressure	$\pm \frac{1}{2}$	[Note (1)]

NOTES:

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

(2) a new reference value, or set of reference values, shall be determined in accordance with [ISTF-3300](#). If new reference values are determined, deviations from the previous and new reference values shall be evaluated, and verification that the new values represent acceptable pump operation shall be placed in the record of tests (see [ISTF-9000](#)).

(b) Determine whether the pump periodic verification test is required.

ISTF-3320 Establishment of Additional Set of Reference Values. If it is necessary or desirable, for some reason other than stated in [ISTF-3310](#), to establish an additional set of reference values, an inservice test shall be run at the conditions of an existing set of reference values and the results analyzed. If operation is acceptable per [ISTF-6200](#), an additional set of reference values may be established as follows:

(a) For centrifugal and vertical line shaft pumps, the additional set of reference values shall be determined from the pump curve established in [ISTF-5110](#) or [ISTF-5210](#), as applicable. Vibration acceptance criteria shall be established by an inservice test at the new reference point. If vibration data were taken at all points used in determining the pump curve, an interpolation of the new vibration reference value is acceptable.

(b) For positive displacement pumps, the additional set of reference values shall be established per [ISTF-5310](#).

A test shall be run to verify the new reference values before their implementation. Whenever an additional set of reference values is established, the reasons for so doing shall be justified and documented in the record of tests (see [ISTF-9000](#)). The requirements of [ISTF-3300](#) apply.

ISTF-3400 Frequency of Inservice Tests

An inservice test shall be run on each pump quarterly. For those pumps identified in [ISTF-1300\(d\)](#), a pump periodic verification test shall be performed biennially in accordance with this Subsection. The Owner is not required to perform a pump periodic verification test, if the design basis accident flow rate in the Owner's safety analysis is less than or equal to the inservice pump test.

ISTF-3410 Pumps in Regular Use. Pumps that are operated more frequently than every 3 months need not be run or stopped for a special test, provided the plant records show the pump was operated at least once every 3 months at the reference conditions, and the quantities specified were determined, recorded, and analyzed per [ISTF-6000](#).

ISTF-3420 Pumps Out of Service. For a pump declared inoperable or not required to be operable, the test schedule need not be followed. Within 3 months before the pump is placed in an operable status, the pump shall be tested and the test schedule followed in accordance with the requirements of this Subsection. Pumps whose drivers require that the plant be in operation to operate (e.g., steam driven) shall be tested within 1 week following plant startup.

ISTF-3500 Data Collection

ISTF-3510 General

(22)

(a) **Accuracy.** Instrument accuracy shall be within the limits of [Table ISTF-3510-1](#). If a parameter is determined by analytical methods instead of measurement, then the determination shall meet the parameter accuracy requirement of [Table ISTF-3510-1](#) (e.g., flow rate determination shall be accurate to within $\pm 2\%$ of actual). For individual analog instruments, the required accuracy is percent of full-scale. For digital instruments, the required accuracy is over the calibrated range. For a combination of instruments, the required accuracy is loop accuracy.

(b) Range

(1) The full-scale range of each analog instrument shall be not greater than 3 times the reference value.

(2) Digital instruments shall be selected such that the reference value does not exceed 90% of the calibrated range of the instrument.

(3) Vibration instruments are excluded from the range requirements of (1) and (2).

(c) *Instrument Location.* The sensor location shall be established by the Owner, documented in the plant records (see [ISTF-9000](#)), and shall be appropriate for the parameter being measured. The same location shall be used for subsequent tests. Instruments that are position sensitive shall be permanently mounted or provision shall be made to duplicate their position during each test.

(d) *Fluctuations.* Symmetrical damping devices or averaging techniques may be used to reduce instrument fluctuations. Hydraulic instruments may be damped by using gage snubbers or by throttling small valves in instrument lines.

(e) *Frequency Response Range*

(1) For pumps operating at or above 600 rpm, the frequency response range of the vibration-measuring transducers and their readout system shall be from one-third minimum pump shaft rotational speed to at least 1,000 Hz.

(2) For slow speed pumps operating below 600 rpm, the frequency response range of the vibration-measuring transducers and their readout system shall be no lower than 1 Hz to at least 1,000 Hz.

ISTF-3520 Pressure

(a) *Gage Lines.* If the presence or absence of liquid in a gage line could produce a difference of more than 0.25% in the indicated value of the measured pressure, means shall be provided to ensure or determine the presence or absence of liquid as required for the static correction used.

(b) *Differential Pressure.* When determining differential pressure across a pump, a differential pressure gage or a differential pressure transmitter that provides direct measurement of the pressure difference or the difference between the pressure at a point in the inlet and the pressure at a point in the discharge pipe shall be used.

ISTF-3530 Rotational Speed. Rotational speed measurements of variable speed pumps shall be taken by a method that meets the requirements of [ISTF-3510](#).

(22) ISTF-3540 Vibration

(a) On centrifugal pumps, except vertical line shaft pumps, measurements shall be taken in a plane approximately perpendicular to the rotating shaft in two approximately orthogonal directions on each accessible pump-bearing housing. Measurement shall also be taken in the axial direction on each accessible pump-thrust-bearing housing.

(b) On vertical line shaft pumps, measurements shall be taken on the upper motor-bearing housing in three approximately orthogonal directions, one of which is the axial direction.

(c) On reciprocating pumps, the location shall be on the bearing housing of the crankshaft, approximately perpendicular to both the crankshaft and the line of plunger travel.

(d) If a portable vibration indicator is used, the measurement points shall be clearly identified on the pump to permit subsequent duplication in both location and plane.

(e) Pumps that will use the minimum reference value for one or more vibration points shall use trending analysis of measured vibration amplitudes in the frequency domain to assess performance at these locations. The Owner shall document the conclusion of the performance analysis prior to the subsequent test with a conclusion of acceptable, degrading but acceptable, or unacceptable. Corrective action shall be initiated when an unacceptable trend in performance is identified.

If a supplemental monitoring activity identifies a parameter outside the normal operating range or identifies a trend toward an unacceptable degraded state, action shall be taken to

(1) identify and document the condition in the corrective action program established in accordance with the Owner's quality assurance program

(2) increase monitoring to establish the rate of change of the monitored parameter

(3) review component-specific information to identify the degradation cause

(4) develop a plan to remove the pump from service to perform maintenance prior to significant performance degradation

(5) address potential generic concerns applicable to other pumps based on the results of the analysis of the specific pump performance

ISTF-3550 Flow Rate. When measuring flow rate, a rate or quantity meter shall be installed in the pump test circuit. If a meter does not indicate the flow rate directly, the record shall include the method used to reduce the data. Internal recirculated flow is not required to be measured. External recirculated flow is required to be measured if such flow is present during the design function of the pump.

ISTF-4000 TO BE PROVIDED AT A LATER DATE

ISTF-5000 SPECIFIC TESTING REQUIREMENTS

A baseline test may be substituted for any inservice test.

ISTF-5100 Centrifugal Pumps (Except Vertical Line Shaft Centrifugal Pumps)

(a) *Duration of Tests.* For the inservice test, after pump conditions are as stable as the system permits, each pump shall be run at least 2 min. At the end of this time at least one measurement or determination of each of the quantities required by [Table ISTF-3000-1](#) shall be made and recorded.

(b) *Bypass Loops.* A bypass test loop may be used for an inservice test, provided the flow rate through the loop meets the requirements as specified in [ISTF-3300](#).

ISTF-5110 Baseline Testing. The parameters to be measured are specified in [Table ISTF-3000-1](#).

(a) Flow rate and differential pressure shall be measured at a minimum of five points. If practicable, these points shall be from pump minimum flow to at least pump design flow. A pump curve shall be established based on the measured points. At least one point shall be designated as the reference point(s). Data taken at the reference point will be used to compare the results of inservice tests.

(b) Vibration measurements are only required to be taken at the reference point(s).

(22) **ISTF-5120 Inservice Testing.** Inservice tests shall be conducted with the pump operating at a specified reference point and within the variances from the reference point as described in this paragraph. The test parameters shown in [Table ISTF-3000-1](#) shall be determined and recorded as required by this paragraph. The test shall be conducted as follows:

(a) The pump shall be operated at nominal motor speed for constant speed drives or at a speed adjusted to the reference point ($\pm 1\%$) for variable speed drives.

(b) The resistance of the system shall be varied until the flow rate is as close as practical to the reference point with the variance not to exceed $+2\%$ or -1% of the reference point. The differential pressure shall then be determined and compared to its reference value. Alternatively, the flow rate shall be varied until the differential pressure is as close as practical to the reference point with the variance not to exceed $+1\%$ or -2% and the flow rate determined and compared to its reference value.

(c) Vibration (displacement or velocity) shall be determined and compared with corresponding reference values. Vibration measurements are to be an overall value, without filtering, of velocity or displacement. If velocity measurements are used, they shall be peak. If displacement amplitudes are used, they shall be peak-to-peak.

(d) All deviations from the reference values shall be compared with the ranges of [Table ISTF-5120-1](#) and corrective action taken as specified in [ISTF-6200](#). The vibration measurements shall be compared to both the relative and absolute criteria shown in the alert and required action ranges of [Table ISTF-5120-1](#). For example, if vibration exceeds either $6 V_r$ or 0.7 in./sec (1.7 cm/s), the pump is in the required action range.

ISTF-5130 Periodic Verification Test.³ Tests shall be performed for pumps identified via [ISTF-1300\(d\)](#). If the required flow and differential pressure cannot be

³ The Owner is not required to perform a pump periodic verification test if the design basis accident flow rate in the Owner's safety analysis is less than or equal to the inservice pump test.

achieved, then the pump is in the Action Range, and corrective actions shall be taken in accordance with [ISTF-6200\(b\)](#).

ISTF-5200 Vertical Line Shaft Centrifugal Pumps

(a) *Duration of Tests.* For the inservice test, after pump conditions are as stable as the system permits, each pump shall be run at least 2 min. At the end of this time at least one measurement or determination of each of the quantities required by [Table ISTF-3000-1](#) shall be made and recorded.

(b) *Bypass Loops.* A bypass test loop may be used for an inservice test, provided the flow rate through the loop meets the requirements as specified in [ISTF-3300](#).

ISTF-5210 Baseline Testing. The parameters to be measured are specified in [Table ISTF-3000-1](#).

(a) Flow rate and differential pressure shall be measured at a minimum of five points. If practicable, these points shall be from pump minimum flow to at least pump design flow. A pump curve shall be established based on the measured points. At least one point shall be designated as the reference point(s). Data taken at the reference point shall be used to compare the results of inservice tests.

(b) Vibration measurements are only required to be taken at the reference point(s).

ISTF-5220 Inservice Testing. Tests shall be conducted (22) with the pump operating at a specified reference point and within the variances from the reference point as described in this paragraph. The test parameters shown in [Table ISTF-3000-1](#) shall be determined and recorded as required by this paragraph. The test shall be conducted as follows:

(a) The pump shall be operated at nominal motor speed for constant speed drives or at a speed adjusted to the reference point ($\pm 1\%$) for variable speed drives.

(b) The resistance of the system shall be varied until the flow rate is as close as practical to the reference point with the variance not to exceed $+2\%$ or -1% of the reference point. The differential pressure shall then be determined and compared to its reference value. Alternatively, the flow rate shall be varied until the differential pressure is as close as practical to the reference point with the variance not to exceed $+1\%$ or -2% and the flow rate determined and compared to its reference value.

(c) Vibration (displacement or velocity) shall be determined and compared with corresponding reference values. Vibration measurements are to be an overall value, without filtering, of velocity or displacement. If velocity measurements are used, they shall be peak. If displacement amplitudes are used, they shall be peak-to-peak. (See [Figure ISTB-5223-1](#).)

(d) All deviations from the reference values shall be compared with the ranges of [Table ISTF-5220-1](#) and corrective action taken as specified in [ISTF-6200](#). The

Table ISTF-5120-1
Centrifugal Pump Test Acceptance Criteria

(22)

Test Type	Pump Speed	Test Parameter	Acceptable Range	Alert Range	Required Action Range	
					Low	High
Inservice test [Notes (1), (2)]	N/A	Q	$0.94Q_r$ to $1.06Q_r$	$0.90Q_r$ to $<0.94Q_r$	$<0.90Q_r$	$>1.06Q_r$
	N/A	ΔP	$0.93\Delta P_r$ to $1.06\Delta P_r$	$0.90\Delta P_r$ to $<0.93\Delta P_r$	$<0.90\Delta P_r$	$>1.06\Delta P_r$
	<600 rpm	V_v [Note (3)]	≤ 0.125 in./sec (≤ 0.3 cm/s)	>0.125 in./sec to 0.300 in./sec (>0.3 cm/s to 0.7 cm/s)	None	>0.300 in./sec (>0.7 cm/s)
		V_d or V_v	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$ or >10.5 mils to 22 mils (>266.7 μm to 558.8 μm)	None	$>6V_r$ or >22 mils (>558.8 μm)
	≥ 600 rpm	V_v [Note (3)]	≤ 0.125 in./sec (≤ 0.3 cm/s)	>0.125 in./sec to 0.300 in./sec (>0.3 cm/s to 0.7 cm/s)	None	>0.300 in./sec (>0.7 cm/s)
		V_d or V_v	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$ or >0.325 in./sec to 0.7 in./sec (>0.8 cm/s to 1.7 cm/s)	None	$>6V_r$ or >0.7 in./sec (>1.7 cm/s)

GENERAL NOTE: The subscript r denotes reference value, the subscript v denotes vibration velocity reference value, and the subscript d denotes displacement.

NOTES:

- (1) Vibration parameter per Table ISTF-3000-1. V_r is vibration reference value in the selected units.
- (2) Refer to Figure ISTB-5223-1 to establish displacement limits for pumps with speeds ≥ 600 rpm or velocity limits for pumps with speeds < 600 rpm.
- (3) Pumps that will use the minimum reference value for one or more vibration points shall use trending analysis of measured vibration amplitudes in the frequency domain to assess performance at these locations (see ISTF-3540).

vibration measurements shall be compared to both the relative and absolute criteria shown in the alert and required action ranges of Table ISTF-5220-1. For example, if vibration exceeds either $6V_r$ or 0.7 in./sec (1.7 cm/s), the pump is in the required action range.

ISTF-5230 Periodic Verification Test.³ Tests shall be performed for pumps identified via ISTF-1300(d). If the required flow and differential pressure cannot be achieved, then the pump is in the Action Range, and corrective actions shall be taken in accordance with ISTF-6200(b).

ISTF-5300 Positive Displacement Pumps

(a) *Duration of Tests.* For the inservice test, after pump conditions are as stable as the system permits, each pump shall be run at least 2 min. At the end of this time at least one measurement or determination of each of the quantities required by Table ISTF-3000-1 shall be made and recorded.

(b) *Bypass Loops.* A bypass test loop may be used for an inservice test, provided the flow rate through the loop meets the requirements as specified in ISTF-3300.

ISTF-5310 Baseline Testing. The parameters to be measured are specified in Table ISTF-3000-1.

(a) For positive displacement pumps, reference values shall be taken at or near pump design pressure for the parameters specified in Table ISTF-3000-1.

(b) Vibration measurements are only required to be taken at the reference point(s).

ISTF-5320 Inservice Testing. Tests shall be conducted with the pump operating at a specified reference point and within the variances from the reference point as described in this paragraph. The test shall be conducted as follows:

(a) The pump shall be operated at nominal motor speed for constant speed drives or at a speed adjusted to the reference point ($\pm 1\%$) for variable speed drives.

(b) The resistance of the system shall be varied until the discharge pressure is as close as practical to the reference point with the variance not to exceed $+2\%$ or -1% of the reference point. The flow rate shall then be determined and compared to its reference value.

(c) Vibration (displacement or velocity) shall be determined and compared with corresponding reference values. Vibration measurements are to be an overall value, without filtering, of velocity or displacement. If velocity measurements are used, they shall be peak. If displacement amplitudes are used, they shall be peak-to-peak.

(d) All deviations from the reference values shall be compared with the ranges of Table ISTF-5320-1 or Table ISTF-5320-2, as applicable, and corrective action taken as specified in ISTF-6200. For reciprocating positive displacement pumps, vibration measurements shall be compared to the relative criteria shown in the alert and required action ranges of Table ISTF-5320-1. For all other positive displacement pumps, vibration

Table ISTF-5220-1
Vertical Line Shaft and Centrifugal Pump Test Acceptance Criteria

(22)

Test Type	Pump Speed	Test Parameter	Acceptable Range	Alert Range	Required Action Range	
					Low	High
Inservice test [Notes (1), (2)]	N/A	Q	$0.95Q_r$ to $1.06Q_r$	$0.93Q_r$ to $<0.95Q_r$	$<0.93Q_r$	$>1.06Q_r$
	N/A	ΔP	$0.95\Delta P_r$ to $1.06\Delta P_r$	$0.93\Delta P_r$ to $<0.95\Delta P_r$	$<0.93\Delta P_r$	$>1.06\Delta P_r$
	<600 rpm	V_v [Note (3)]	≤ 0.125 in./sec (≤ 0.3 cm/s)	>0.125 in./sec to 0.300 in./sec (>0.3 cm/s to 0.7 cm/s)	None	>0.300 in./sec (>0.7 cm/s)
		V_d or V_v	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$ or >10.5 mils to 22 mils ($>266.7 \mu\text{m}$ to $558.8 \mu\text{m}$)	None	$>6V_r$ or >22 mils ($>558.8 \mu\text{m}$)
	≥ 600 rpm	V_v [Note (3)]	≤ 0.125 in./sec (≤ 0.3 cm/s)	>0.125 in./sec to 0.300 in./sec (>0.3 cm/s to 0.7 cm/s)	None	>0.300 in./sec (>0.7 cm/s)
		V_d or V_v	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$ or >0.325 in./sec to 0.7 in./sec (>0.8 cm/s to 1.7 cm/s)	None	$>6V_r$ or >0.7 in./sec (>1.7 cm/s)

GENERAL NOTE: The subscript r denotes reference value, the subscript v denotes vibration velocity reference value, and the subscript d denotes displacement.

NOTES:

- (1) Vibration parameter per Table ISTF-3000-1. V_r is vibration reference value in the selected units.
- (2) Refer to Figure ISTB-5223-1 to establish displacement limits for pumps with speeds ≥ 600 rpm or velocity limits for pumps with speeds < 600 rpm.
- (3) Pumps that will use the minimum reference value for one or more vibration points shall use trending analysis of measured vibration amplitudes in the frequency domain to assess performance at these locations (see ISTF-3540).

measurements shall be compared to both the relative and absolute criteria shown in the alert and required action ranges of Table ISTF-5320-2. For example, if vibration exceeds either $6V_r$ or 0.7 in./sec (1.7 cm/s), the pump is in the required action range.

ISTF-5330 Periodic Verification Test.³ Tests shall be performed for pumps identified via ISTF-1300(d). If the required flow and discharge pressure cannot be achieved, then the pump is in the Action Range, and corrective actions shall be taken in accordance with ISTF-6200(b).

ISTF-6000 MONITORING, ANALYSIS, AND EVALUATION

If anomalous data were obtained during a test with no clear indication of systematic error, then the cause shall be attributed to the pump under test, and ISTF-6200 applies. If readily apparent that the anomalous data were caused by a systematic error, such as improper system lineup or inaccurate instrumentation, then ISTF-6300 applies.

ISTF-6100 Trending

Test parameters shown in Table ISTF-3000-1, except for fixed values, shall be trended.

ISTF-6200 Corrective Action

(a) *Alert Range.* If the measured test parameter values fall within the alert range of Table ISTF-5120-1, Table ISTF-5220-1, Table ISTF-5320-1, or Table ISTF-5320-2, as applicable, the frequency of testing specified in ISTF-3400 shall be doubled until the cause of the deviation is determined and the condition is corrected, or an analysis of the pump is performed in accordance with (c).

(b) *Action Range.* If the pump periodic verification test flow or pressure parameter is not met or a measured test parameter value falls within the required action range of Table ISTF-5120-1, Table ISTF-5220-1, Table ISTF-5320-1, or Table ISTF-5320-2, as applicable, the pump shall be declared inoperable until either the cause of the deviation has been determined and the condition is corrected, or an analysis of the pump is performed in accordance with (c).

(c) *Analysis.* In cases where the pump's test parameters are within either the alert or the required action ranges of Table ISTF-5120-1, Table ISTF-5220-1, Table ISTF-5320-1, or Table ISTF-5320-2, as applicable, an analysis may be performed that supports the pump's continued use at the changed values. This analysis shall include verification of the pump's operational readiness. The analysis shall include both a pump level and a system level evaluation of operational readiness, the cause of the change in pump performance, and an evaluation of all trends indicated by available data. The analysis shall also consider whether new reference values should be

Table ISTF-5320-1
Positive Displacement Pump (Except Reciprocating) Test Acceptance Criteria

(22)

Test Type	Pump Speed	Test Parameter	Acceptable Range	Alert Range	Required Action Range	
					Low	High
Inservice test [Notes (1), (2)]	N/A	Q	$0.95Q_r$ to $1.06Q_r$	$0.93Q_r$ to $<0.95Q_r$	$<0.93Q_r$	$>1.06Q_r$
	N/A	P	$0.93P_r$ to $1.06P_r$	$0.90P_r$ to $<0.93P_r$	$<0.90P_r$	$>1.06P_r$
	<600 rpm	V_v [Note (3)]	≤ 0.125 in./sec (≤ 0.3 cm/s)	>0.125 in./sec to 0.300 in./sec (>0.3 cm/s to 0.7 cm/s)	None	>0.300 in./sec (>0.7 cm/s)
		V_d or V_v	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$ or >10.5 mils to 22 mils (>266.7 μm to 558.8 μm)	None	$>6V_r$ or >22 mils (>558.8 μm)
	≥ 600 rpm	V_v [Note (3)]	≤ 0.125 in./sec (≤ 0.3 cm/s)	>0.125 in./sec to 0.300 in./sec (>0.3 cm/s to 0.7 cm/s)	None	>0.300 in./sec (>0.7 cm/s)
		V_d or V_v	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$ or >0.325 in./sec to 0.7 in./sec (>0.8 cm/s to 1.7 cm/s)	None	$>6V_r$ or >0.7 in./sec (>1.7 cm/s)

GENERAL NOTE: The subscript r denotes reference value, the subscript v denotes vibration velocity reference value, and the subscript d denotes displacement.

NOTES:

- (1) Vibration parameter per Table ISTF-3000-1. V_r is vibration reference value in the selected units.
- (2) Refer to Figure ISTB-5223-1 to establish displacement limits for pumps with speeds ≥ 600 rpm or velocity limits for pumps with speeds < 600 rpm.
- (3) Pumps that will use the minimum reference value for one or more vibration points shall use trending analysis of measured vibration amplitudes in the frequency domain to assess performance at these locations (see ISTF-3540).

Table ISTF-5320-2
Reciprocating Positive Displacement Pump Test Acceptance Criteria

(22)

Test Type	Pump Speed	Test Parameter	Acceptable Range	Alert Range	Required Action Range	
					Low	High
Inservice test	N/A	Q	$0.95Q_r$ to $1.06Q_r$	$0.93Q_r$ to $<0.95Q_r$	$<0.93Q_r$	$>1.06Q_r$
	N/A	P	$0.93P_r$ to $1.06P_r$	$0.90P_r$ to $<0.93P_r$	$<0.90P_r$	$>1.06P_r$
	N/A	V_v [Note (1)]	≤ 0.125 in./sec (≤ 0.3 cm/s)	>0.125 in./sec to 0.300 in./sec (>0.3 cm/s to 0.7 cm/s)	None	>0.300 in./sec (>0.7 cm/s)
	N/A	V_d or V_v	$\leq 2.5V_r$	$>2.5V_r$ to $6V_r$	None	$>6V_r$

GENERAL NOTE: The subscript r denotes reference value, the subscript v denotes vibration velocity reference value, and the subscript d denotes displacement.

NOTE: (1) Pumps that will use the minimum reference value for one or more vibration points shall use trending analysis of measured vibration amplitudes in the frequency domain to assess performance at these locations (see ISTF-3540).

established and shall justify the adequacy of the new reference values, if applicable. The results of this analysis shall be documented in the record of tests (see ISTF-9000).

ISTF-6300 Systematic Error

When a test shows measured parameter values that fall outside of the acceptable range of Table ISTF-5120-1, Table ISTF-5220-1, Table ISTF-5320-1, or Table ISTF-5320-2, as applicable, that have resulted from an identified systematic error, such as improper system lineup or inaccurate instrumentation, the test shall be rerun after correcting the error.

ISTF-6400 Analysis of Related Conditions

If the reference value of a particular parameter being measured or determined can be significantly influenced by other related conditions, then these conditions shall be analyzed⁴ and documented in the record of tests (see ISTF-9000).

⁴Vibration measurements of pumps may be foundation, driver, or piping dependent. Therefore, if initial vibration readings are high and have no obvious relationship to the pump, then vibration measurements should be taken at the driver, at the foundation, and on the piping and analyzed to ensure that the reference vibration measurements are representative of the pump and the measured vibration levels will not prevent the pump from fulfilling its function.

ISTF-7000 TO BE PROVIDED AT A LATER DATE**ISTF-8000 TO BE PROVIDED AT A LATER DATE****ISTF-9000 RECORDS AND REPORTS****ISTF-9100 Pump Records**

The Owner shall maintain a record that shall include the following for each pump covered by this Subsection:

(a) the name of the manufacturer, and the manufacturer's model and serial numbers or other identification number

(b) a copy or summary of the manufacturer's acceptance test report if available

(c) a copy of the pump manufacturer's operating limits

(d) maintain the necessary records for the pump periodic verification tests, including the applicable test parameters (e.g., flow rate and associated differential pressure, or flow rate and associated discharge pressure, and speed for variable speed pumps) and their basis

ISTF-9200 Test Plans

In addition to the requirements of [ISTA-3110](#) and [ISTA-3160](#), the test plans and procedures shall include the following:

(a) type of each pump

(b) the hydraulic circuit to be used

(c) the location and type of measurement for the required test parameters

(d) the method of determining test parameter values that are not directly measured by instrumentation

ISTF-9300 Record of Tests

See [ISTA-9230](#).

ISTF-9400 Record of Corrective Action

See [ISTA-9240](#).

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Division 1, Mandatory Appendix I¹

Inservice Testing of Pressure Relief Devices

in Water-Cooled Reactor Nuclear Power Plants

I-1000 GENERAL REQUIREMENTS

I-1100 Applicability

The requirements of this Appendix apply to certain pressure relief devices [included in the ASME Boiler and Pressure Vessel Code (ASME BPVC), Section III].

I-1120 Limitations

(a) The requirements of this Appendix recognize differences between the installed operating conditions and the conditions under which a pressure relief device may be tested. For a specific pressure relief device design, if the parameter to be tested is dependent on conditions not specifically addressed by these requirements, the installed operating condition and the test condition shall be comparable, or proven correlations shall be applied.

(b) The requirements of this Appendix apply only to pressure relief devices required for overpressure protection.

(c) The requirements of this Appendix are not intended to demonstrate conformance to design specification requirements.

(d) The requirements of this Appendix are not intended to verify or demonstrate all aspects of pressure relief device operation.

I-1200 Definitions

The following definitions are provided to ensure a uniform understanding of select terms used in this Appendix. Definitions for other related pressure relief device terms can be found in ASME PTC 25, Pressure Relief Devices.

ambient temperature: the temperature range of the environment surrounding a pressure relief device at its installed plant location during the phase(s) of plant operation for which the device is required for overpressure protection.

assist device: a pneumatic, hydraulic, or mechanical device applied to a pressure relief valve for set-pressure testing to assist inlet static pressure in opening the valve.

auxiliary actuating device: a device requiring an external energy source to provide inservice remote actuation capability of a pressure relief valve with inlet static pressure below set-pressure.

bellows alarm switch: an electropneumatic switch used in pilot-operated pressure relief valves to detect a failure of the pressure integrity of the pilot bellows, the failure of which may prevent opening of the primary valve.

control rings: internal rings used to adjust the opening characteristic, blowdown, and lift of a pressure relief valve.

gag: a mechanical device installed on a pressure relief valve to restrict or prevent lift.

historical data form: a form for recording test results and maintenance history of a pressure relief device.

normal system operating conditions (fluid, pressure, temperature): system fluid, pressure, and temperature range during the phase(s) of plant operation for which that system is intended to function.

overpressure protection: the means by which components are protected from overpressure by the use of pressure relieving devices or other design provisions as required by the ASME BPVC, Section III, or other applicable construction codes.

power-actuated relief valve: a relief valve in which the major relieving device is combined with and controlled by a device requiring an external source of energy.

remote actuation: actuation of a pressure relief device through a generated signal rather than by inlet static pressure.

thermal relief application: a relief device whose only overpressure protection function is to protect isolated components, systems, or portions of systems from fluid expansion caused by changes in fluid temperature.

valve group: valves of the same manufacturer, type, system application, and service media.

¹This Appendix contains requirements to augment the rules of Subsection ISTC.

I-1300 Guiding Principles

I-1310 General

(a) *Operation and Maintenance Instructions.* Complete operation and maintenance instructions shall be available for each device. This Appendix shall be supplemented by these operating and maintenance instructions.

(b) *Valve Testing Frequency.* A frequency for valve testing is required by this Appendix to provide assurance of the valve operational readiness.

(c) *Valve Disassembly.* This Appendix does not require valves or accessories to be disassembled or removed from their installed position.

(d) *Visual Examination.* Visual examinations shall be performed in accordance with the Owner's examination procedures and shall be documented.

(e) *Acceptance Criteria.* The Owner, based upon system and valve design basics or technical specification, shall establish and document acceptance criteria for tests required by this Appendix.

I-1320 Test Frequencies, Class 1 Pressure Relief Valves

(a) Test Interval — Options 1 and 2

(1) *Option 1: 5-yr Test Interval.* Class 1 pressure relief valves shall be tested at least once every 5 yr, starting with initial electric power generation. No maximum limit is specified for the number of valves to be tested within each interval; however, a minimum of 20% of the valves from each valve group shall be tested within any 24-month interval. The valve(s) chosen to make up this 20% shall consist of valves within the same group that have not been tested during the current interval, if they exist. If all valves within the group have been tested within the current test interval, the valve(s) chosen should be valve(s), within the same group, that have not been tested for the longest period of time. The test interval for any installed valve shall not exceed 5 yr. The 5-yr test interval shall begin from the date of the as-left set-pressure test for each valve.

(2) *Option 2: 6-yr Test Interval.* If selected as an alternative to the 5-yr test interval required by (1), Class 1 pressure relief valves shall be tested at least once every 6 yr, provided that each valve is disassembled and inspected after as-found set-pressure testing to verify that parts are free of defects resulting from time-related degradation or service-induced wear. A minimum of 20% of the valves from each valve group shall be tested within any 24-month interval. This 20% shall consist of valves that have not been tested during the current interval, if they exist. Based upon the inspection, the owner shall determine the need for additional inspections or testing to address any generic concerns. As-left set pressure testing shall be performed following maintenance and prior to returning the valve to service. The 6-yr test interval for each valve shall begin from the

date of the as-left set-pressure test for each valve. Each valve shall have been disassembled and inspected prior to the start of the 6-yr test interval. Disassembly and inspection performed prior to the implementation of the 6-yr test interval may be used.

(b) *Replacement With Pretested Valves.* The Owner may satisfy testing requirements by installing pretested valves to replace valves that have been in service, provided that

(1) for replacement of a partial complement of valves, the valves removed from service shall be tested prior to resumption of electric power generation or

(2) for replacement of a full complement of valves, the valves removed from service shall be tested within 12 months of removal from the system

(c) *Requirements for Testing Additional Valves.* Additional valves shall be tested in accordance with the following requirements:

(1) For each valve tested for which the as-found set-pressure (first test actuation) exceeds the greater of either the plus/minus tolerance limit of the Owner-established set-pressure acceptance criteria of I-1310(e) or $\pm 3\%$ of valve nameplate set-pressure, two additional valves shall be tested from the same valve group.

(2) If the as-found set-pressure of any of the additional valves tested in accordance with (1) exceeds the criteria noted therein, then all remaining valves of that same valve group shall be tested.

(3) The Owner shall evaluate the cause and effect of valves that fail to comply with the set-pressure acceptance criteria established in (1) or the Owner-established acceptance criteria for other required tests, such as the acceptance of auxiliary actuating devices, compliance with Owner's seat-tightness criteria, etc. Based upon this evaluation, the Owner shall determine the need for testing in addition to the minimum tests specified in (c) to address any generic concerns that could apply to valves in the same or other valve groups.

I-1330 Test Frequency, Class 1 Nonreclosing Pressure Relief Devices. Class 1 nonreclosing pressure relief devices shall be replaced every 5 yr unless historical data indicate a requirement for more frequent replacement.

I-1340 Test Frequency, Class 1 Pressure Relief Valves That Are Used for Thermal Relief Application. Tests shall be performed in accordance with I-1320, Test Frequencies, Class 1 Pressure Relief Valves.

I-1350 Test Frequency, Classes 2 and 3 Pressure Relief Valves Except Pressurized Water Reactor (PWR) Main Steam Safety Valves

(a) Test Interval

(1) The maximum allowable time between tests for any valve, with the exception of PWR main steam safety valves, shall not exceed 10 yr, starting with initial electric power generation.

(2) For valve groups containing only one valve, the valve shall be tested at least every 48 months.

(3) For valve groups containing more than one valve, a minimum of 20% of the valves from each valve group shall be tested within any 48-month interval. The valve(s) chosen to make up this 20% shall consist of valves within the same group that have not been tested during the current test interval, if they exist. If all valves within the group have been tested within the current test interval, the valve(s) chosen should be valve(s), within the same group, that have not been tested for the longest period of time.

The test interval shall begin from the date of the as-left set-pressure test for each valve. PWR main steam safety valves shall be tested in accordance with I-1320.

(b) *Replacement With Pretested Valves.* The Owner may satisfy testing requirements by installing pretested valves to replace valves that have been in service, provided that

(1) for replacement of a partial complement of valves, the valves removed from service shall be tested within 3 months of removal from the system or before resumption of electric power generation, whichever is later or

(2) for replacement of a full complement of valves, the valves removed from service shall be tested within 12 months of removal from the system

(c) *Requirements for Testing Additional Valves.* Additional valves shall be tested in accordance with the following requirements:

(1) For each valve tested for which the as-found set-pressure (first test actuation) exceeds the greater of either the plus/minus tolerance limit of the Owner-established set-pressure acceptance criteria of I-1310(e) or $\pm 3\%$ of valve nameplate set-pressure, two additional valves shall be tested from the same valve group.

(2) If the as-found set-pressure of any of the additional valves tested in accordance with (1) exceeds the criteria noted therein, then all remaining valves of that same valve group shall be tested.

(3) The Owner shall evaluate the cause and effect of valves that fail to comply with the set-pressure acceptance criteria established in (1) or the Owner-established acceptance criteria for other required tests, such as the acceptance of auxiliary actuating devices, compliance with the Owner's seat-tightness criteria, etc. Based upon this evaluation, the Owner shall determine the need for testing in addition to the minimum tests specified in (c) to address any generic concerns that could apply to valves in the same or other valve groups.

I-1360 Test Frequency, Classes 2 and 3 Nonreclosing Pressure Relief Devices. Classes 2 and 3 nonreclosing pressure relief devices shall be replaced every 5 yr, unless historical data indicates a requirement for more frequent replacement.

I-1370 Test Frequency, Classes 2 and 3 Primary Containment Vacuum Relief Valves

(a) Tests shall be performed on all Classes 2 and 3 containment vacuum relief valves at each refueling outage or every 2 yr, whichever is sooner, unless historical data requires more frequent testing.

(b) Leak tests shall be performed on all Classes 2 and 3 containment vacuum relief valves at a frequency designated by the Owner in accordance with Table ISTC-3500-1.

I-1380 Test Frequency, Classes 2 and 3 Vacuum Relief Valves, Except for Primary Containment Vacuum Relief Valves. All Classes 2 and 3 vacuum relief valves shall be tested every 2 yr, unless performance data indicate the need for more frequent testing or allow for less frequent testing, not to exceed 10 yr.

I-1390 Test Frequency, Classes 2 and 3 Pressure Relief Devices That Are Used for Thermal Relief Application. Tests shall be performed on all Classes 2 and 3 relief devices used in thermal relief application every 10 yr, unless performance data indicate more frequent testing is necessary. In lieu of tests the Owner may replace the relief devices at a frequency of every 10 yr, unless performance data indicate more frequent replacements are necessary.

I-1400 Instrumentation

I-1410 Set-Pressure Measurement Accuracy. Test equipment (e.g., gages, transducers, load cells, calibration standards) used to determine valve set-pressure, shall have an overall combined accuracy not to exceed $\pm 1\%$ of the indicated (measured) set-pressure.

I-2000 INTRODUCTION

I-3000, I-4000, and I-5000 define the requirements for performance testing of pressure relief devices for boiling water reactor (BWR) and PWR nuclear power plants. The valves subject to examination and tests are categorized. Responsibilities, examination methods, examination techniques, test methods, examination and test frequencies, records, and maintenance requirements are defined. Replacement valves of the same valve group shall be tested to the requirements of I-3100 and I-3400. Replacement valves, not of the same valve group previously used, shall be tested to the requirements of I-3100 and I-3200.

I-3000 PRESSURE RELIEF DEVICE TESTING

I-3100 Testing Before Initial Installation

I-3110 Class 1 Main Steam Pressure Relief Valves With Auxiliary Actuating Devices. Tests shall be performed in the following sequence, or manufacturer's production tests may be accepted for (b) through (d),

provided the valve passes visual examination in accordance with the Owner's examination procedures:

- (a) visual examination
- (b) set-pressure determination
- (c) accessories [see I-3310(d) through I-3310(h)]
- (d) determination of compliance with the Owner's seat-tightness criteria

I-3120 Class 1 Safety Valves. Tests shall be performed in the following sequence, or manufacturer's production tests may be accepted for (b), (c), and (d), provided the valve passes visual examination in accordance with the Owner's examination procedures:

- (a) visual examination
- (b) set-pressure determination
- (c) testing of accessories [see I-3320(d) through I-3320(f)]
- (d) determination of compliance with the Owner's seat-tightness criteria

I-3125 Class 1 Power-Actuated Relief Valves. Tests shall be performed in the following sequence, or manufacturer's production tests may be accepted for (b), (c), and (d), provided the valve passes visual examination in accordance with the Owner's examination procedures:

- (a) visual examination
- (b) determination of functional capability
- (c) testing of accessories [see I-3325(d) and I-3325(e)]
- (d) determination of compliance with the Owner's seat-tightness criteria

I-3130 Other Class 1 Pressure Relief Valves. Tests shall be performed in the following sequence, or manufacturer's production tests may be accepted for (b) and (c), provided the valve passes visual examination in accordance with the Owner's examination procedures:

- (a) visual examination
- (b) set-pressure determination
- (c) determination of compliance with the Owner's seat-tightness criteria

I-3140 Class 1 Nonreclosing Pressure Relief Devices. The device shall pass visual examination in accordance with the Owner's examination procedures.

I-3150 Classes 2 and 3 Pressure Relief Valves. Tests shall be performed in the following sequence, or manufacturer's production tests may be accepted for (b) and (c), if the valve passes visual examination in accordance with the Owner's examination procedures:

- (a) visual examination
- (b) set-pressure determination
- (c) determination of compliance with the Owner's seat-tightness criteria

I-3160 Classes 2 and 3 Nonreclosing Pressure Relief Devices. The devices shall pass visual examination in accordance with the Owner's examination procedures.

I-3170 Classes 2 and 3 Vacuum Relief Valves. The valves shall pass visual examination in accordance with the Owner's examination procedures.

I-3200 Testing Before Initial Electric Power Generation

I-3210 Class 1 Main Steam Pressure Relief Valves With Auxiliary Actuating Devices. After installation, safety valves and pilot-operated pressure relief valves equipped with auxiliary actuating devices shall be remotely actuated at reduced or normal system operating pressure to verify open and close capability. Set-pressure verification is not required. Actuation pressure of the auxiliary actuating device sensing element, where applicable, and electrical continuity shall have been verified.

I-3220 Class 1 Safety Valves. Within 6 months before initial reactor criticality, each valve shall have its set pressure verified.

I-3225 Class 1 Power-Actuated Relief Valves. After installation, each valve shall be remotely actuated at normal system operating pressure to verify open and close capability.

I-3230 Other Class 1 Pressure Relief Valves. Functional testing is not required. The device shall pass visual examination in accordance with the Owner's examination procedures.

I-3240 Class 1 Nonreclosing Pressure Relief Devices. Functional testing is not required. The device shall pass visual examination in accordance with the Owner's examination procedures.

I-3250 Classes 2 and 3 Pressure Relief Valves

(a) *PWR Main Steam Safety Valves.* Either before or after installation and within 6 months before initial reactor criticality, each valve shall be subjected to the following tests:

- (1) verification of compliance with the Owner's set-pressure criteria
- (2) verification of compliance with the Owner's seat-tightness criteria

(b) *Other Pressure Relief Valves.* Functional testing is not required. The device shall pass visual examination in accordance with the Owner's examination procedures.

I-3260 Classes 2 and 3 Nonreclosing Pressure Relief Devices. Functional testing is not required. The device shall pass visual examination in accordance with the Owner's examination procedures.

I-3270 Classes 2 and 3 Vacuum Relief Valves

(a) After installation, these valves shall be actuated to verify open and close capability and performance of any pressure- and position-sensing accessories.

(b) Compliance with the Owner's seat-tightness criteria shall be verified.

I-3300 Periodic Testing

Periodic testing of all pressure relief devices is required. No maintenance, adjustment, disassembly, or other activity that could affect "as found" set-pressure or seat-tightness data is permitted prior to testing. Control ring adjustment is permitted per I-4110(g) and I-4120(g). Test frequencies are specified in I-1320, I-1330, I-1340, I-1350, I-1360, I-1370, I-1380, and I-1390. When on-line testing is performed to satisfy periodic testing requirements, visual examination may be performed out of sequence.

I-3310 Class 1 Main Steam Pressure Relief Valves With Auxiliary Actuating Devices. Tests before maintenance or set-pressure adjustment, or both, shall be performed for (a), (b), and (c) in sequence. The remaining shall be performed after maintenance or set-pressure adjustments.

- (a) visual examination
- (b) seat-tightness determination,² if practicable
- (c) set-pressure determination
- (d) determination of electrical characteristics and pressure integrity of solenoid valve(s)
- (e) determination of pressure integrity and stroke capability of air actuator
- (f) determination of operation and electrical characteristics of position indicators
- (g) determination of operation and electrical characteristics of bellows alarm switch
- (h) determination of actuating pressure of auxiliary actuating device sensing element, where applicable, and electrical continuity
- (i) determination of compliance with the Owner's seat-tightness criteria

I-3320 Class 1 Safety Valves. Tests before maintenance or set-pressure adjustment, or both, shall be performed for (a), (b), and (c) in sequence. The remaining shall be performed after maintenance or set-pressure adjustment.

- (a) visual examination
- (b) seat-tightness determination,² if practicable
- (c) set-pressure determination
- (d) determination of operation and electrical characteristics of bellows alarm switch
- (e) verification of the integrity of the balancing device on balanced valves
- (f) determination of operation and electrical characteristics of position indicators

² This test need not be performed at the same pressure as the final seat tightness test. This test may be quantitative or qualitative, dependent on the observed condition. This test is primarily for gross determination of "as found" seat tightness.

(g) determination of compliance with the Owner's seat-tightness criteria

I-3325 Class I Power-Actuated Relief Valves. Tests before maintenance shall be performed for (a), (b), and (c) in sequence. The remaining shall be performed after maintenance or set-pressure adjustment.

- (a) visual examination
- (b) seat-tightness determination,² if practicable
- (c) set-pressure determination
- (d) verification of the integrity of the balancing device on balanced valves
- (e) determination of operation and electrical characteristics of position indicators
- (f) determination of compliance with the Owner's seat-tightness criteria

I-3330 Other Class 1 Pressure Relief Valves. Tests before maintenance or set-pressure adjustment, or both, shall be performed for (a), (b), and (c) in sequence. The remaining shall be performed after maintenance or set-pressure adjustment.

- (a) visual examination
- (b) seat-tightness determination,² if practicable
- (c) set-pressure determination
- (d) verification of the integrity of the balancing device on balanced valves
- (e) determination of operation and electrical characteristics of position indicators
- (f) determination of compliance with the Owner's seat-tightness criteria

I-3340 Class 1 Nonreclosing Pressure Relief Devices. The device shall be periodically replaced in accordance with I-1330. The replacement device shall be visually examined at the time of installation and shall meet the acceptance criteria established by the Owner's examination procedure.

I-3350 Classes 2 and 3 Pressure Relief Valves. Tests before maintenance or set-pressure adjustment, or both, shall be performed for (a), (b), and (c) in sequence. The remaining shall be performed after maintenance or set-pressure adjustment.

- (a) visual examination
- (b) seat-tightness determination,² if practicable
- (c) set-pressure determination
- (d) verification of the integrity of the balancing device on balanced valves
- (e) determination of compliance with the Owner's seat-tightness criteria

I-3360 Classes 2 and 3 Nonreclosing Pressure Relief Devices. The device shall be periodically replaced in accordance with I-1360. The replacement device shall be visually examined at the time of installation and shall meet the acceptance criteria established by the Owner's examination procedure.

I-3370 Classes 2 and 3 Vacuum Relief Valves

(a) The valves shall be actuated to verify open and close capability, set-pressure, and performance of any pressure and position-sensing accessories.

(b) Compliance with the Owner's seat-tightness criteria shall be determined.

I-3400 Disposition After Testing or Maintenance**I-3410 Class 1 Main Steam Pressure Relief Valves With Auxiliary Actuating Devices**

(a) Valves and accessories that comply with their respective acceptance criteria for the tests specified may be returned to service without further testing, except as required by (d).

(b) Valves and accessories that do not comply with their respective acceptance criteria shall be adjusted, refurbished, or replaced, in accordance with written procedures. Valves shall be adjusted to meet the acceptance criteria of I-1310(e).

(c) Refurbished equipment shall be subjected to the test(s) specified in I-3310, as applicable. If disassembly includes valve disk (main) components, then valve disk stroke capability shall be verified by mechanical examination or tests.

(d) Each valve with an auxiliary actuating device that has been removed for maintenance or testing and reinstalled after meeting the requirements of I-3310, shall have the electrical and pneumatic connections verified through either mechanical/electrical inspection or test prior to the resumption of electric power generation. Main disk movement and set-pressure verification are not required.

(e) Valves and accessories that do not comply with their respective acceptance criteria, whether the problem is associated with the component, the system, or associated equipment, shall be evaluated to determine the ability of the valve to perform its intended function until the next testing interval or maintenance opportunity. Corrective actions shall be taken, as appropriate, to ensure valve operability.

I-3420 Class 1 Safety Valves

(a) Valves and accessories that comply with their respective acceptance criteria for the tests specified may be returned to service without further testing.

(b) Valves and accessories that do not comply with their respective acceptance criteria shall be adjusted, refurbished, or replaced in accordance with written procedures. Valves shall be adjusted to meet the acceptance criteria of I-1310(e).

(c) Refurbished equipment shall be subjected to the test(s) specified in I-3320, as applicable. If disassembly includes valve disk (main) components, then valve disk stroke capability shall be verified by mechanical examination or tests.

(d) Valves and accessories that do not comply with their respective acceptance criteria, whether the problem is associated with the component, the system, or associated equipment, shall be evaluated to determine the ability of the valve to perform its intended function until the next testing interval or maintenance opportunity. Corrective actions shall be taken, as appropriate, to ensure valve operability.

I-3425 Class I Power-Actuated Relief Valves

(a) Valves and accessories that comply with their respective acceptance criteria for the tests specified may be returned to service without further testing.

(b) Valves that do not comply with their respective acceptance criteria shall be adjusted, refurbished, or replaced in accordance with written procedure. Valves shall be adjusted to meet the acceptance criteria of I-1310(e).

(c) Refurbished equipment shall be subjected to test(s) specified in I-3325, as applicable. If disassembly includes valve disk (main) components, then valve disk stroke capability shall be verified by mechanical examination or tests.

(d) Valves and accessories that do not comply with their respective acceptance criteria, whether the problem is associated with the component, the system, or associated equipment, shall be evaluated to determine the ability of the valve to perform its intended function until the next testing interval or maintenance opportunity. Corrective actions shall be taken, as appropriate, to ensure valve operability.

I-3430 Other Class 1 Pressure Relief Valves

(a) Valves and accessories that comply with their respective acceptance criteria for the tests specified may be returned to service without further testing.

(b) Valves and accessories that do not comply with their respective acceptance criteria shall be adjusted, refurbished, or replaced in accordance with written procedures. Valves shall be adjusted to meet the acceptance criteria of I-1310(e).

(c) Refurbished equipment shall be subjected to the test(s) specified in I-3330, as applicable. If disassembly includes valve disk (main) components, then valve disk stroke capability shall be verified by mechanical examination or tests.

(d) Valves and accessories that do not comply with their respective acceptance criteria, whether the problem is associated with the component, the system, or associated equipment, shall be evaluated to determine the ability of the valve to perform its intended function until the next testing interval or maintenance opportunity. Corrective actions shall be taken, as appropriate, to ensure valve operability.

I-3440 Class 1 Nonreclosing Pressure Relief Devices.

The device shall be periodically replaced in accordance with I-1330. The replacement device shall be visually examined at the time of installation and shall meet the acceptance criteria established by the Owner's examination procedure.

I-3450 Classes 2 and 3 Pressure Relief Valves

(a) Valves that comply with their respective acceptance criteria for the tests specified may be returned to service without further testing.

(b) Valves that do not comply with their respective acceptance criteria shall be adjusted, refurbished, or replaced in accordance with written procedures. Valves shall be adjusted to meet the acceptance criteria of I-1310(e).

(c) Refurbished equipment shall be subjected to the test(s) specified in I-3350, as applicable. If disassembly includes valve disk (main) components, then valve disk stroke capability shall be verified by mechanical examination or tests.

(d) Valves and accessories that do not comply with their respective acceptance criteria, whether the problem is associated with the component, the system, or associated equipment, shall be evaluated to determine the ability of the valve to perform its intended function until the next testing interval or maintenance opportunity. Corrective actions shall be taken, as appropriate, to ensure valve operability.

I-3460 Classes 2 and 3 Nonreclosing Pressure Relief Devices. The device shall be periodically replaced in accordance with I-1360. The replacement device shall be visually examined at the time of installation and shall meet the acceptance criteria established by the Owner's examination procedure.

I-3470 Classes 2 and 3 Vacuum Relief Valves

(a) Valves that comply with their respective acceptance criteria for the tests specified may be returned to service without further testing.

(b) Valves that do not comply with their respective acceptance criteria shall be adjusted, refurbished, or replaced in accordance with written procedures. Valves shall be adjusted to meet the acceptance criteria of I-1310(e).

(c) Valves that have been refurbished shall be subjected to the test(s) specified in I-3370.

(d) Valves and accessories that do not comply with their respective acceptance criteria, whether the problem is associated with the component, the system, or associated equipment, shall be evaluated to determine the ability of the valve to perform its intended function until the next testing interval or maintenance opportunity. Corrective actions shall be taken, as appropriate, to ensure valve operability.

I-4000 TEST METHODS**I-4100 Set-Pressure Testing****I-4110 Steam Service**

(a) *Test Media.* Valves designed to operate on steam, including safety valves designed for saturated steam service that are installed on a water-filled loop seal, shall be set-pressure tested with saturated steam. Alternative compressive fluids may be used as the test media, if correlation data between the alternative fluid and steam have been established. The requirements of I-4300 shall apply for testing with alternative test media.

(b) *Accumulator Volume.* The volume of the accumulator drum and the pressure source flow rate shall be sufficient to determine the valve set-pressure. Valves may have their lifts restricted during set-pressure testing.

(c) *Assist Devices.* Assist devices may be used for set-pressure testing, provided the accuracy complies with the requirements of I-1400.

(d) *Thermal Equilibrium.* Ambient temperature and test media temperature shall be established and valve thermal equilibrium confirmed before starting set-pressure testing. The valve shall be considered at thermal equilibrium only when the valve body temperature has stabilized and does not change more than 10°F (5.5°C) in 30 min as measured directly or determined by correlation from other valve temperature measurements. Valves insulated in service shall be insulated in a like manner during testing.

Verification of thermal equilibrium is not required for valves that are tested at ambient temperature using a test medium at ambient temperature.

(e) *Ambient Temperature.* The ambient temperature of the operating environment shall be simulated during the set-pressure test. If the effect of ambient temperature on set-pressure can be established for a particular valve type, then the valve may be set-pressure tested using an ambient temperature different from the operating ambient temperature. Correlations between the operating and testing ambient temperatures shall comply with the requirements of I-4320 and I-4330.

(f) Superimposed Back Pressure

(1) Consideration of variable or constant back pressure in set-pressure setting is not required for balanced pressure relief valves, if the back pressure does not exceed 50% of the valve set-pressure. However, the set-pressure shall consider the effects of bonnet pressure when the bonnet vent is piped to a pressure or vacuum discharge other than atmospheric.

(2) Constant superimposed back pressure in set-pressure setting shall be considered for nonbalanced pressure relief valves when the back pressure exceeds 1% of the set-pressure. For conventional nonbalanced valves with constant superimposed back pressure, the required

set-pressure shall be calculated by subtracting the superimposed back pressure from the stamped set-pressure.

(g) *Control Rings.* Adjustment of control rings to ensure valve action is permitted. For set-pressure acceptance testing, control ring positions shall not be altered between successive openings. Adjusted control rings shall be returned to their proper operating position prior to return to service, as documented by the Owner.

(h) *Time Between Valve Openings.* A minimum of 5 min shall elapse between successive openings.

(i) *Number of Tests.* The number of openings at set-pressure shall be sufficient to demonstrate satisfactory repeatability with a minimum of two consecutive openings within acceptance criteria. Any subsequent openings at the same set-point adjustment shall be within acceptance criteria.

I-4120 Compressible Fluid Services Other Than Steam

(a) *Test Media.* Valves shall be tested with the normal system operating conditions. The test media temperature shall be established such that it can be duplicated as near as practicable during subsequent tests. Alternative compressible fluids and different temperatures may be used, provided the requirements of I-4300 are met. Air or nitrogen may be substituted at the same temperature without alternative media testing per I-4300.

(b) *Accumulator Volume.* The volume of the accumulator drum and the pressure source flow rate shall be sufficient to determine the valve set-pressure. Valves may have their lifts restricted during set-pressure testing.

(c) *Assist Devices.* Assist devices may be used for set-pressure testing, provided the accuracy complies with the requirements of I-1400.

(d) *Thermal Equilibrium.* Ambient temperature and test media temperature shall be established and valve thermal equilibrium confirmed before starting set-pressure testing. The valve shall be considered at thermal equilibrium only when the valve body temperature has stabilized and does not change more than 10°F (5.5°C) in 30 min as measured directly or determined by correlation from other valve temperature measurements. Valves insulated in service shall be insulated in a like manner during testing.

Verification of thermal equilibrium is not required for valves that are tested at ambient temperature using a test medium at ambient temperature.

(e) *Ambient Temperature.* The ambient temperature of the operating environment shall be simulated during the set-pressure test. The ambient temperature shall be established such that it can be duplicated as near as practicable during subsequent tests. If the effect of ambient temperature on set-pressure can be established for a particular valve type, then the valve may be set-pressure tested using an ambient temperature different from the operating ambient temperature. Correlations between the

operating and testing ambient temperatures shall comply with the requirements of I-4320 and I-4330.

(f) Superimposed Back Pressure

(1) Consideration of variable or constant back pressure in set-pressure setting is not required for balanced pressure relief valves, if the back pressure does not exceed 50% of the valve set-pressure. However, the set-pressure shall consider the effects of bonnet pressure when the bonnet vent is piped to a pressure or vacuum discharge other than atmospheric.

(2) Constant superimposed back pressure in set-pressure setting shall be considered for nonbalanced pressure relief valves when the back pressure exceeds 1% of the set-pressure. For conventional nonbalanced valves with constant superimposed back pressure, the required set-pressure shall be calculated by subtracting the superimposed back pressure from the stamped set-pressure.

(g) *Control Rings.* Adjustment of control rings to ensure valve action is permitted. For set-pressure acceptance testing, control ring positions shall not be altered between successive openings. Adjusted control rings shall be returned to their proper operating position prior to return to service, as documented by the Owner.

(h) Time Between Valve Openings

(1) There is no required minimum time between openings when the temperatures of the test medium, valve body, and ambient conditions all are within 10°F (5.5°C) of each other.

(2) A minimum of 5 min shall elapse between successive openings for all other tests.

(i) *Number of Tests.* The number of openings at set-pressure shall be sufficient to demonstrate satisfactory repeatability with a minimum of two consecutive openings within acceptance criteria. Any subsequent openings at the same set-point adjustment shall be within acceptance criteria.

I-4130 Liquid Service

(a) *Test Media.* Valves shall be tested with the normal system operating conditions. The test media temperature shall be established such that it can be duplicated as near as practicable during subsequent tests. Alternative liquids and different temperatures may be used, provided the requirements of I-4300 are met.

(b) *Accumulator Volume.* There is no requirement of minimum accumulator volume; however, the pressure tap for determining set-pressure shall be located at the valve inlet.

(c) *Assist Devices.* Assist devices to determine set-pressure are not permitted for liquid service pressure relief valves.

(d) *Thermal Equilibrium.* Ambient temperature and test media temperature shall be established and valve thermal equilibrium confirmed before starting set-pressure testing. The valve shall be considered at thermal equilibrium only when the valve body temperature has

stabilized and does not change more than 10°F (5.5°C) in 30 min as measured directly or determined by correlation from other valve temperature measurements. Valves insulated in service shall be insulated in a like manner during testing.

Verification of thermal equilibrium is not required for valves that are tested at ambient temperature using a test medium at ambient temperature.

(e) *Ambient Temperature.* The ambient temperature of the operating environment shall be simulated during the set-pressure test. The ambient temperature shall be established such that it can be duplicated as near as practicable during subsequent tests. If the effect of ambient temperature on set-pressure can be established for a particular valve type, then the valve may be set-pressure tested using an ambient temperature different from the operating ambient temperature. Correlations between the operating and testing ambient temperatures shall comply with the requirements of I-4320 and I-4330.

(f) *Superimposed Back Pressure*

(1) Consideration of variable or constant back pressure in set-pressure setting is not required for balanced pressure relief valves, if the back pressure does not exceed 50% of the valve set-pressure. However, the set-pressure shall consider the effects of bonnet pressure when the bonnet vent is piped to a pressure or vacuum discharge other than atmospheric.

(2) Constant superimposed back pressure in set-pressure setting shall be considered for nonbalanced pressure relief valves when the back pressure exceeds 1% of the set-pressure. For conventional nonbalanced valves with constant superimposed back pressure, the required set-pressure shall be calculated by subtracting the superimposed back pressure from the stamped set-pressure.

(g) *Time Between Valve Openings*

(1) There is no required minimum time between openings when the temperatures of the test medium, valve body, and ambient conditions all are within 10°F (5.5°C) of each other.

(2) A minimum of 5 min shall elapse between successive openings for all other tests.

(h) *Number of Tests.* The number of openings at set-pressure shall be sufficient to demonstrate satisfactory repeatability with a minimum of two consecutive openings within acceptance criteria. Unless otherwise stated in the test procedure, valve opening pressure shall be that inlet pressure when a continuous, unbroken stream of liquid is emanating from the valve outlet.

I-4200 Seat Tightness Testing

Seat tightness testing shall be performed in accordance with the Owner's valve test procedure. Consideration shall be given to test media, temperature stability, and ambient temperature, as required in I-4100.

Seat tightness testing shall be performed using the same fluid used for set-pressure testing, except as provided by I-4300.

I-4210 Inlet Pressure. The inlet pressure for seat leak testing shall be in accordance with one of the following:

(a) maximum system operating pressure

(b) 90% of spring setting or 5 psig (34 kPa) below spring setting for valves having a spring set-pressure less than 50 psig (344 kPa)

(c) pressure established in Owner's valve test procedure

I-4220 Acceptable Seat Tightness Testing Methods. Table I-4220-1 provides acceptable methods. Other methods may be determined by the Owner.

I-4230 Acceptance Criteria for Seat Leakage Testing.

Either the original valve equipment design specification criteria or acceptance criteria established by the Owner in the valve test procedure shall be used for valve seat leakage acceptance criteria.

I-4300 Alternative Test Media

Pressure relief devices may be subjected to set-pressure tests and seat-tightness tests using a test medium (fluid and temperature) other than that for which they are designed, provided the testing complies with I-4310, I-4320, and I-4330.

I-4310 Correlation. Correlation of pressure relief device operation, with respect to the parameter under test, shall be established for the specified alternative media, as compared with the operating media.

I-4320 Certification of Correlation Procedure. The Owner shall ensure that the correlation established in accordance with the procedure will be of sufficient accuracy such that the pressure relief devices tested or adjusted, or both, using the alternate media, will comply with the acceptance criteria of the following:

(a) I-1320(c) or I-1350(c) for determining the need to test additional valves

(b) I-4110(i), I-4120(i), or I-4130(h) for testing or adjusting valves, or both, for reuse

(c) I-4230 for determining seat tightness

Results of the tests performed to verify the adequacy of the alternate test media correlation shall be documented.

I-4330 Procedure. A written procedure shall be prepared by the Owner or the Owner's designee and certified in accordance with the requirements of I-4320. The procedure shall specify all test parameters that affect correlation and shall include, but not be limited to, the following:

(a) specific description of test setup

(b) specific requirements for instrumentation

(c) specific requirements for assist equipment (if any)

Table I-4220-1
Seat Tightness Testing Methods for Pressure Relief Devices

(22)

Test Method	Service Fluid			Remarks
	Steam	Air/Gas	Liquids	
Audible/visible	X	X	X	...
API STD 527	X [Note (1)]	X [Note (1)]	...	...
Air/gas under water	X	X	...	...
Downstream temperature measurement	X	X	X	Installed valves only
Weighed condensate	X [Note (1)]	...	...	Min. 10 min test
Volumetric or weight measurement	...	...	X	Min. 10 min test
Cold bar	X [Note (2)]	...	...	...
Acoustic emission	X	X	X	...

NOTES:

(1) On exposed spring valves, care must be exercised to ensure against leakage past the valve stem and adjacent valve pieces.

(2) Defined as 1 in. diameter polished stainless steel bar at a temperature less than 100°F passed in the plane parallel to the outlet flange face.

(d) specific requirements for test operating conditions (e.g., device temperature, ambient temperature, ambient pressure, etc.)

Test parameters shall be listed (e.g., time between openings, number of tests, etc.)

I-5000 RECORDS AND RECORD KEEPING

I-5100 Requirements

The Owner shall maintain a record that shall include the following for each valve covered by this Appendix:

(a) the manufacturer and manufacturer's model and serial number, or other identifiers

(b) a copy or summary of the manufacturer's acceptance test report, if available

(c) preservice test results

I-5200 Record of Test

In addition to the requirements of [ISTA-9230](#), if testing is performed in accordance with [I-4300](#), a copy of the alternate test media correlation, test procedure, and documentation of results of test performed to verify the adequacy of the alternate test media shall be retained.

I-5300 Record of Modification and Corrective Action

In addition to the requirements of [ISTA-9240](#), the following requirements shall be met:

(a) The Owner shall document all modifications performed or corrective actions taken that affect the set pressure of pressure relief devices or valves. The documentation shall also include any recommendations or modifications suggested by the manufacturer. Modification or corrective action, as outlined, shall be recorded and maintained for the period of time as outlined in the Owner's technical specifications.

(b) Any device modification or adjustment that affects nameplate data shall be recorded on a data sheet. The modification or adjustment shall be made in accordance with the manufacturer's published information or shall have the concurrence of the manufacturer.

An additional nameplate, not bearing a Code symbol stamp, shall be installed to reflect the new data and reference to records maintained by the Owner outlining the modification.

Division 1, Mandatory Appendix II¹

Check Valve Condition-Monitoring Program

II-1000 PURPOSE

This Appendix establishes the requirements for implementing and maintaining a check valve condition-monitoring program as discussed in [ISTC-5222](#).

(22) II-1100 Supplemental Definitions

The following definition is provided to ensure a uniform understanding of selected terms used in this Appendix:

trendable attribute: an Owner-selected parameter of a check valve test or examination which can be used to monitor component degradation with the intent of ensuring the component is capable of performing its intended function.

II-2000 GROUPINGS

Groupings shall be determined by the Owner. Groupings shall be technically justified and shall be based on

- (a) the intended purpose of the condition-monitoring program [e.g., improve performance, or optimize testing, examination, and preventive maintenance (PM) activities]
- (b) analysis of test results and maintenance history
- (c) design characteristics, application, and service conditions

The Owner shall assess the significance to plant safety if an extended test or examination interval is planned.

The Owner should also consider the sample disassembly examination program grouping details of [ISTC-5221\(c\)](#).

II-3000 ANALYSIS

The Owner shall perform an analysis of the test and maintenance history of a valve or group of valves in order to establish the basis for specifying inservice testing, examination, and PM activities. The analysis shall include the following:

- (a) Identify any common failure or maintenance patterns.
- (b) Analyze the following patterns to determine their significance and to identify potential failure mechanisms:
 - (1) determine whether certain PM activities would mitigate the failure or maintenance patterns

- (2) determine whether certain condition-monitoring tests such as nonintrusive testing are feasible and effective in monitoring for these failure mechanisms

- (3) determine whether periodic disassembly and examination activities would be effective in monitoring for these failure mechanisms

- (4) determine whether changes in the valve groupings are required

II-4000 CONDITION-MONITORING ACTIVITIES (22)

Valve obturator movement during applicable test or examination activities shall be sufficient to determine the bidirectional functionality of the moving parts. A full open exercise test, or an open test to the position required to perform its intended function (see [ISTA-1100](#)), is not required for this assessment.

(a) Performance Improvement Activities

- (1) If sufficient information is not currently available to complete the analysis required in [II-3000](#), or if this analysis is inconclusive, then the following activities shall be performed at sufficient intervals over an interim period of the next 5 yr or two refueling outages, whichever is less, to determine the cause of the failure or the maintenance patterns:

- (-a) Identify interim tests (e.g., nonintrusive tests) to assess the performance of the valve or the group of valves.

- (-b) Identify interim examinations to evaluate potential degradation mechanisms.

- (-c) Identify other types of analysis that will be performed to assess check valve condition.

- (-d) Identify which of these activities will be performed on each valve in the group.

- (-e) Identify the interval of each activity.

- (2) Identify trendable attribute(s) that will be trended and evaluated. Trending and evaluation of existing data must be used as the bases to reduce or extend the time interval between tests or examinations.

- (3) Complete or revise the condition-monitoring program test plans (see [II-6000](#)) to document the check valve program performance improvement activities and their associated frequencies.

- (4) Perform these activities at their associated intervals until

- (-a) sufficient information is obtained to permit an adequate evaluation of the specific application or

¹ This Appendix contains requirements to augment the rules of Subsection [ISTC](#).

(-b) until the end of the interim period

(5) After completion of II-4000(a)(1), II-4000(a)(2), II-4000(a)(3), and II-4000(a)(4), review those attributes that were selected for trending, along with the results of each activity and trends to determine whether any changes to the performance improvement program are required. If needed based on the results of the last scheduled test or examination, the program shall be revised in accordance with the site corrective action program prior to the performance of any activity on the next valve in the group, and the applicable requirements of II-2000, II-3000, and II-4000 shall be repeated.

(b) *Optimization of Condition-Monitoring Activities*

(1) If sufficient information is available to assess the performance adequacy of the check valve or the group of check valves, then the following activities shall be performed:

(-a) Identify the applicable PM activities including their associated intervals that are required to maintain the continued acceptable performance of the check valve or group of check valves.

(-b) Identify the applicable examination activities including their associated intervals that will be used to periodically assess the condition of each check valve or group of check valves.

(-c) Identify the applicable test activities including their associated intervals that will be used to periodically verify the acceptable performance of each check valve or group of check valves.

(-d) Identify which of these activities will be performed on each valve in the group.

(-e) Identify the interval of each activity. Initial intervals shall be established using (b), provided that the condition-monitoring test and examination intervals consider plant safety and are supported by the trending and evaluation of industry and plant-specific performance data. Trending and evaluation shall be used to support the conclusion that the valve or group of valves is capable of performing its intended function(s) over the entire interval. At least one of the identified activities for a valve group shall be performed on each valve of the group not to exceed the maximum interval shown in Table II-4000-1.

(-f) Interval extensions shall be limited to one fuel cycle or 2 yr, whichever is longer, per extension. All valves in a group-sampling plan must be tested or examined again, before the interval can be extended again, or until the maximum interval would be exceeded.

(-g) Intervals shall not exceed the maximum intervals shown in Table II-4000-1. The requirements of ISTA-3120, Inservice Examination and Test Interval, do not apply.

(-h) In lieu of the requirement of (-f), the interval of applicable test activities of containment isolation valves with a Type C leakage rate requirement based on Appen-

dix J program commitments shall be determined in accordance with the Owner's 10 CFR 50, Appendix J Program.

(2) Identify trendable attribute(s) that will be trended and evaluated. Trending and evaluation of existing data must be used to reduce or extend the time interval between tests or examinations.

(3) Revise the test plans (see II-6000) to document the optimized condition-monitoring program activities, and the associated intervals of each activity.

(4) Perform these activities at their associated intervals.

(5) After completion of II-4000(b)(1), II-4000(b)(2), II-4000(b)(3), and II-4000(b)(4), review those attributes that were selected for trending, along with the results of each activity and trends to determine whether any changes to the optimized program are required. If needed based on the results of the last scheduled test or examination, the program shall be revised in accordance with the site corrective action program prior to the performance of any activity on the next valve in the group, and the applicable requirements of II-2000, II-3000, and II-4000 shall be repeated.

Changes to IST intervals must consider plant safety and be supported by trending and evaluating both industry and plant-specific performance data to ensure the component is capable of performing its intended function(s) over the entire interval.

II-5000 CORRECTIVE MAINTENANCE

If corrective maintenance is performed on a check valve, the analysis used to formulate the basis of the condition-monitoring activities for that valve and its associated valve group shall be reviewed to determine whether any

Table II-4000-1
Maximum Intervals for Use
When Applying Internal Extensions

Group Size [Note (1)]	Maximum Interval Between Activities of Member Valves in the Groups, yr [Note (2)]	Maximum Interval Between Activities of Each Valve in the Groups, yr
≥4	4.5	16
3	4.5	12
2	6.0	12
1	N/A	10

NOTES:

- (1) The maximum interval was determined by how many interval extensions could be obtained based on an 18-month or 24-month fuel cycle. All of the valves had to be tested or examined within the maximum interval to be considered a valid extension.
- (2) These intervals shall not exceed intervals imposed by other station programs where activities are credited for meeting the requirements of condition monitoring (e.g., Containment Leakage Rate Testing Program).

changes are required. If significant changes are required, the program shall be revised and the applicable requirements of II-2000, II-3000, and II-4000 shall be repeated.

II-6000 DOCUMENTATION

The condition-monitoring program shall be documented and shall include the following information:

- (a) list of valves in the program
- (b) list of valves in each valve group

(c) dates valves were added/deleted to the program and the reason for their inclusion/deletion

(d) analysis forming the basis for the program

(e) identified failure or maintenance history patterns for each valve

(f) condition-monitoring program activities, including the trended attributes and the bases for the associated intervals for each valve or valve group

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Division 1, Mandatory Appendix III¹

Preservice and Inservice Testing of Active Electric Motor-Operated Valve Assemblies in Water-Cooled Reactor Nuclear Power Plants

III-1000 INTRODUCTION

III-1100 Applicability

This Appendix establishes the requirements for preservice and inservice testing to assess the operational readiness of active motor-operated valves (MOVs) in water-cooled reactor nuclear power plants.

III-1200 Scope

See [ISTC-1200](#).

III-2000 SUPPLEMENTAL DEFINITIONS

full cycle exercise: full stroke of the valve from and back to its initial position.

motor-operated valve (MOV): a valve and its associated electric motor driven mechanism for positioning the valve, including components that control valve action and provide position output signals.

MOV functional margin: the increment by which an MOV's available capability exceeds the capability required to operate the MOV under design basis conditions.

preventive maintenance (PM): maintenance activities designed to prevent or minimize the effects of various degradation mechanisms.

stem factor: the ratio of stem torque to stem thrust in rising-stem valves.

III-3000 GENERAL TESTING REQUIREMENTS

III-3100 Design Basis Verification Test

A one-time test shall be conducted to verify the capability of each MOV to meet its safety-related design basis requirements. This test shall be conducted at conditions as close to design basis conditions as practicable. Requirements for a design basis verification test are specified in applicable regulatory documents. Testing that meets the requirements of this Appendix but

conducted before implementation of this Appendix may be used.

(a) Design basis verification test data shall be used in conjunction with preservice test data as the basis for inservice test criteria.

(b) Design basis verification testing shall be conducted in situ or in a prototype test facility that duplicates applicable design basis conditions. If a test facility is used, an engineering analysis shall be documented that supports applicability to the in situ conditions.

(c) Justification for testing at conditions other than design basis conditions and for grouping like MOVs shall be documented by an engineering evaluation, alternate testing techniques, or both. Where design basis testing of the specific MOV being evaluated is impracticable, or not meaningful (provides no additional useful data), data from other MOVs may be used if justified by engineering evaluation. Sources for the data include other plant MOVs or test data published in industry testing programs. Where analytical techniques are used to verify design basis capability, those techniques shall be justified by an engineering evaluation.

(d) For certain valve types (i.e., ball, plug, and diaphragm valves) where the need for design basis verification testing has not been previously identified, an engineering evaluation of operating experience may be used to verify design basis capability.

(e) The design basis verification test shall be repeated if an MOV application is changed, the MOV is physically modified, or the system is modified in a manner that invalidates its current design basis verification test results or data. A determination that a design basis verification test is still valid shall be justified by an engineering evaluation, alternative testing techniques, or both.

III-3200 Preservice Test

Each MOV shall be tested during the preservice test period or before implementing inservice testing. These tests shall be conducted under conditions as near as practicable to those expected during subsequent inservice testing. Testing that meets the requirements of this Appendix but conducted before implementation of this

¹This Appendix contains requirements to augment the rules of [Subsection ISTC](#).

Appendix may be used. Only one preservice test of each MOV is required unless, as described in III-3400, the MOV has undergone maintenance that could affect its performance.

III-3300 Inservice Test

Inservice testing shall commence when the MOV is required to be operable to fulfill its required function(s), as described in III-1100, and shall be sufficient to assess changes in MOV functional margin consistent with III-6000.

(a) MOVs may be grouped for inservice testing as described in III-3500.

(b) Inservice tests shall be conducted in the as-found condition. Activities shall not be conducted if they invalidate the inservice test results. If maintenance is needed between the inservice tests, see III-3400. As-found testing is not required prior to maintenance activities as long as the MOV is not due for an inservice test. If maintenance activities are scheduled concurrently with an MOV's inservice test, then the inservice test shall be conducted in the as-found condition, prior to the maintenance activity.

(c) The inservice testing program will include a mix of static and dynamic MOV performance testing. The mix of MOV performance testing may be altered when justified by an engineering evaluation of test data.

(d) Dynamic MOV performance testing is not required for certain valve types (i.e., ball, plug, and diaphragm valves), with acceptable operating experience.

(e) Remote position indication shall be verified locally during inservice testing or maintenance activities.

(22) **III-3310 Inservice Test Interval.** The inservice test interval determination shall include the following:

(a) The inservice test interval shall be determined in accordance with III-6440.

(b) If insufficient data exist to determine the inservice test interval in accordance with III-6400, then MOV inservice testing shall be conducted every two refueling cycles or 3 yr (whichever is longer) until sufficient data exist, from an applicable MOV or MOV group, to justify a longer inservice test interval. Not later than 5 yr or three refueling outages (whichever is longer) after initial implementation of this Appendix, the Owner shall evaluate the adequacy of the MOV diagnostic test interval per III-6440.

(c) The maximum inservice test interval shall not exceed 10 yr. MOV inservice tests conducted per III-3400 may be used to satisfy this requirement.

III-3400 Effect of MOV Replacement, Repair, or Maintenance

When an MOV or its control system is replaced, repaired, or undergoes maintenance that could affect the valve's performance, new inservice test values shall be determined, or the previously established inservice

test values shall be confirmed before the MOV is returned to service. If the MOV was not removed from service, inservice test values shall be immediately determined or confirmed. This testing is intended to demonstrate that performance parameters, which could be affected by the replacement, repair, or maintenance, are within acceptable limits. The Owner's program shall define the level of testing required after replacement, repair, or maintenance. Deviations between the previous and new inservice test values shall be identified and analyzed. Verification that the new values represent acceptable operation shall be documented as described in III-9000, Records and Reports.

III-3410 Preventive Maintenance. PM activities that might affect MOV functional margin and were in place during the design basis verification test in accordance with III-3100 shall be carried forward to the inservice test interval in accordance with III-3300, unless justified by an engineering evaluation. Changes to PM activities that might affect MOV functional margin shall be evaluated and the inservice test criteria adjusted as appropriate.

III-3500 Grouping of MOVs for Inservice Testing

Grouping MOVs for inservice testing is permissible. Grouping MOVs shall be justified by an engineering evaluation, alternative testing techniques, or both. The following shall be satisfied when grouping MOVs:

(a) MOVs with identical or similar motor-operators and valves and with similar plant service conditions may be grouped together based on the results of design basis verification and preservice tests. Functionality of all groups of MOVs shall be validated by appropriate inservice testing of one or more representative valves. Each MOV in a group shall be inservice tested within the maximum test interval specified in III-3310(c).

(b) Test results shall be evaluated and justified for all MOVs in the group.

III-3600 MOV Exercising Requirements

III-3610 Normal Exercising Requirements. All MOVs, within the scope of this Appendix, shall be full cycle exercised at least once per refueling cycle with the maximum time between exercises to be not greater than 24 months. Full cycle operation of an MOV, as a result of normal plant operations or Code requirements, may be considered an exercise of the MOV, if documented. If full stroke exercising of an MOV is not practical during plant operation or cold shutdown outages, full stroke exercising shall be performed during the plant's refueling outage.

III-3620 Additional Exercising Requirements. The (22) Owner shall consider more frequent exercising requirements for MOVs in any of the following categories:

(a) MOVs with high risk significance as required by III-3721

(b) MOVs with adverse or harsh environmental conditions or

(c) MOVs with any abnormal characteristics (operational, design, or maintenance conditions)

III-3700 Risk-Informed MOV Inservice Testing

Risk-informed MOV inservice testing that incorporates risk insights in conjunction with performance margin to establish MOV grouping, acceptance criteria, exercising requirements and testing interval may be implemented.

III-3710 Risk-Informed Considerations. The Owner shall consider the following when incorporating risk insights in the inservice testing of MOVs:

(a) develop an acceptable risk basis for MOV risk determination

(b) develop MOV screening criteria to determine each MOVs contribution to risk

(c) finalize risk category by a documented evaluation from a Plant Expert Panel

- (22) **III-3720 Risk-Informed Criteria.** Each MOV shall be evaluated and categorized using a documented risk ranking methodology that has been accepted by the regulatory authorities having jurisdiction at the plant site. This Appendix provides test requirements for high and low safety significant component (HSSC/LSSC) categories. If an Owner established more than two risk categories, then the Owner shall evaluate the intermediate SSCs and select HSSC or LSSC test requirements for those intermediate SSCs.

III-3721 HSSC MOVs. HSSC MOVs shall be tested in accordance with III-3300 and exercised in accordance with III-3600. HSSC MOVs that can be operated during plant operation shall be exercised quarterly, unless the potential increase in CDF and LERF associated with a longer exercise interval is small.

III-3722 LSSC MOVs. In meeting the provisions of this Appendix, including exercising in accordance with III-3600 and the determination of proper MOV test interval in III-6000, risk insights shall be applied to inservice testing of LSSC MOVs by the following:

(a) LSSC grouping shall be technically justified, but the provision for similarity in III-3500(a) may be relaxed. The provisions in III-3500(b) related to evaluation of test results for MOVs in that group continue to be applicable to all MOVs within the scope of this Appendix.

(b) LSSC MOVs may be associated with an established group of other MOVs. When a member of that group is tested, the test results shall be analyzed and evaluated in accordance with III-6000, and applied to all LSSC MOVs associated with that group.

(c) LSSC MOVs that are not associated with an established group shall be inservice tested, in accordance with III-3300, using an initial test interval of three refueling cycles or 5 yr (whichever is longer) until sufficient

data exist to determine a more appropriate test interval as described in III-6440.

(d) LSSC MOVs shall be inservice tested at least every 10 yr in accordance with III-3310.

III-4000 TO BE PROVIDED AT A LATER DATE

III-5000 TEST METHODS

III-5100 Test Prerequisites

All testing shall be conducted in accordance with plant-specific technical specifications, installation details, acceptance criteria, and maintenance, surveillance, operation, or other applicable procedures.

III-5200 Test Conditions

Test conditions shall be sufficient to determine the MOV's functional margin per III-6400. Test conditions shall be recorded for each test per III-9000.

III-5300 Limits and Precautions

Testing limits and precautions include the following:

(a) MOV exposure to dust, moisture, or other adverse conditions shall be minimized when normally enclosed compartment covers are removed while performing tests.

(b) Manufacturer or vendor limits and precautions associated with the MOV and with the test equipment shall be considered, including the structural thrust and torque limits of the MOV.

(c) Plant-specific operational and design precautions and limits shall be followed. Items to be considered shall include, but are not limited to, water hammer and intersystem relationships.

(d) The benefits of performing a particular test should be balanced against the potential increase in risk for damage caused to the MOV by the particular testing performed.

III-5400 Test Documents

Approved plant documents shall be established for all tests specified in this Appendix and shall provide for

(a) methodical, repeatable, and consistent performance testing

(b) collection of data required to analyze and evaluate the MOV functional margin in accordance with III-6000

III-5500 Test Parameters

Sufficient test parameters shall be selected for measurement to meet the requirements of III-6000 in determining the MOV functional margin.

III-6000 ANALYSIS AND EVALUATION OF DATA

III-6100 Acceptance Criteria

The Owner shall establish methods to determine acceptance criteria for the operational readiness of each MOV within the scope of this Appendix. Acceptance criteria shall be based upon the minimum amount by which available actuator output capability must exceed the valve operating requirements. Thrust, torque, or other measured engineering parameters correlated to thrust or torque consistent with III-6100 through III-6500, may be used to establish the acceptance criteria. Motor control center testing is acceptable if correlation with testing at the MOV has been established. When determining the acceptance criteria, consider the following sources of uncertainty:

- (a) test measurement and equipment accuracy
- (b) valve and actuator repeatability (e.g., torque switch repeatability)
- (c) analysis, evaluation, and extrapolation method
- (d) grouping method

III-6110 Parameter Measurements. MOV margins may be expressed in terms of stem force or other parameters, if those parameters are consistent with III-6100 through III-6500.

(22) III-6200 Analysis of Data

Data obtained from a test required by this Appendix, shall be analyzed to determine if the MOV performance is acceptable. The Owner shall determine which methods are suitable for analyzing necessary parameters for each MOV and application.

Whenever data are analyzed, all relevant operating and test conditions shall be considered.

The Owner shall compare performance test data to the acceptance criteria. If the functional margin, determined per III-6430, does not meet the acceptance criteria, the MOV shall be declared inoperable, in accordance with the Owner's requirements.

Data analysis shall include a qualitative review to identify anomalous behavior. If indications of anomalous behavior are identified, the cause of the behavior shall be analyzed and corrective actions completed, if required.

Test analysis shall be verified by individuals qualified through the Owner's qualification requirements.

(22) III-6300 Evaluation of Data

The Owner shall determine which methods are suitable for evaluating test data for each MOV and application.

The Owner shall have procedural guidelines to establish the methods and timing for evaluating MOV test data. Evaluations shall determine the amount of degradation in functional margin that occurred over time. Evaluations shall consider the influence of past maintenance and test

activities to establish appropriate time intervals for future test activities.

The evaluations shall apply changes in functional margin to other applicable MOVs to establish appropriate time intervals for future test activities.

Test evaluation shall be verified by individuals qualified through the Owner's qualification requirements.

III-6400 Determination of MOV Functional Margin

The Owner shall demonstrate that adequate margin exists between valve operating requirements and the available actuator output capability to satisfy the acceptance criteria for MOV operational readiness. In addition to meeting the acceptance criteria, adequate margin shall exist to ensure that changes in MOV operating characteristics over time do not result in reaching a point at which the acceptance criteria are not satisfied before the next scheduled test activity.

III-6410 Determination of Valve Operating Requirements. Design basis valve operating requirements, including stem factor for rising stem valves, shall be determined from

- (a) measurements taken during testing at design basis conditions
- (b) analytical methods using valve parameters determined from testing at conditions that may be extrapolated to design basis conditions or
- (c) application of justified industry methodologies

III-6420 Determination of Actuator Output Capability

III-6421 Available Output Based on Motor Capabilities. Available actuator output shall be determined based on motor capabilities at the motor's design basis conditions. Considerations shall include

- (a) rated motor start torque
- (b) minimum voltage conditions
- (c) elevated ambient temperature conditions
- (d) operator efficiency
- (e) other appropriate factors

III-6422 Available Output Based on Torque Switch Setting. Where applicable, the available output shall be determined based on the current torque switch setting.

For MOVs where testing does not sufficiently load the MOV to cause torque switch trip (e.g., butterfly and ball valves), available output based on the current torque switch setting shall be determined analytically from test data. Considerations shall include

- (a) calibration of the torque switch spring pack
- (b) the current torque switch setting
- (c) repeatability of torque switch operation

III-6430 Calculation of MOV Functional Margin. MOV functional margin shall be calculated as the difference between the available actuator output and valve operating requirements. Available actuator output is determined as

(a) design basis motor operator capability for limit switch controlled strokes, or

(b) the lesser of design basis motor operator capability or motor operator capability at the current torque switch setting for torque switch controlled strokes

III-6440 Determination of MOV Test Interval. Calculations for determining MOV functional margin shall account for potential performance related degradation. Maintenance activities and associated intervals can affect test intervals and shall be considered. The inservice test interval shall be set such that the MOV functional margin does not decrease below the acceptance criteria.

III-6450 Preventive Maintenance Considerations. Changes to PM activities and their schedule shall be evaluated when establishing acceptance criteria in [III-6100](#), evaluating potential degradation per [III-6300](#), and establishing MOV test intervals per [III-6440](#). For example, changes to stem lubrication procedures, including the lubricant type and application schedule, might impact the engineering evaluations performed in [III-3000](#) and [III-6000](#) and shall be evaluated.

III-6500 Corrective Action

If the MOV performance is unacceptable, as established in [III-6400](#), corrective action shall be taken in accordance with Owner's corrective action requirements.

III-6510 Record of Corrective Action. The Owner shall maintain records of corrective action that shall include a summary of the corrections made, the subsequent tests, confirmation of operational adequacy, and the signature of the individual responsible for corrective action and verification of results.

III-7000 TO BE PROVIDED AT A LATER DATE

III-8000 TO BE PROVIDED AT A LATER DATE

III-9000 RECORDS AND REPORTS

III-9100 Test Information

Pertinent test information shall be recorded or verified for MOV testing, described in [III-3000](#). The following information shall be considered along with the information requirements in ISTA/ISTC:

(a) MOV plant-specific unique identification number.

(b) motor, valve, actuator nameplate data.

(c) test equipment unique identification numbers and equipment calibration dates.

(d) test method and conditions, described in [III-5000](#), including description of valve lineups, process equipment, and type of test. Descriptions shall include valve body, valve stem, electric motor-operator orientation, and piping configuration near the MOV.

(e) breaker setting/fuse size and motor starter thermal overload size, if used.

(f) MOV torque and limit switch configuration and settings.

(g) MOV performance test procedure and other approved plant documents containing acceptance criteria.

(h) name of test performer and date of test.

(i) system flow, system pressure, differential pressure, system fluid temperature, system fluid phase, and ambient temperature.

(j) significant observations: any comments pertinent to the test results that otherwise may not be readily identified by other recorded test data shall be recorded. Observations shall include any remarks regarding abnormal or erratic MOV action noted either during or preceding performance testing and any other pertinent design information that can be verified at the MOV.

III-9200 Documentation of Analysis and Evaluation of Data

(22)

The documentation of acceptable MOV performance, which has been analyzed and evaluated in accordance with [III-6000](#), shall include, as a minimum

(a) values of test data, test parameters, and test information established by [III-5500](#) and [III-9100](#).

(b) summary of analysis and evaluation required per [III-6200](#) and [III-6300](#).

(c) the functional margin established in [III-6400](#)

Test analysis per [III-6200](#) and evaluations per [III-6300](#) shall be verified by individuals qualified through the Owner's qualification requirements. Those analyses and evaluations shall include signatures with dates.

Division 1, Mandatory Appendix IV¹

Preservice and Inservice Testing of Active Pneumatically Operated Valve Assemblies in Nuclear Reactor Power Plants

IV-1000 INTRODUCTION

IV-1100 Applicability

This Appendix establishes the requirements for preservice and inservice testing, as defined in [ISTA-2000](#), to assess the operational readiness of certain active pneumatically operated valves (AOVs) in reactor power plants.

IV-1200 Scope

Certain active pneumatically operated valves and pneumatically operated power-operated relief valves (PORVs) within the scope of [ISTA-1100](#).

IV-1300 Exemptions

In addition to the exemptions specified in [ISTC-1200](#), the following are excluded from this Appendix:

- (a) pneumatically operated dampers
- (b) pneumatically operated check valves
- (c) Category C check valves and safety/relief devices

IV-1400 Owner's Responsibility

In addition to the requirements of [ISTA-1500](#) and [ISTC-1400](#), it is the Owner's responsibility to

(a) Establish performance assessment test acceptance criteria ([IV-6100](#)) and technical basis for applicable AOVs that provide reasonable assurance the pneumatically operated valve is capable of performing its specific function(s) as defined in [ISTA-1100](#). Performance assessment test acceptance criteria that meet the requirements of this Appendix, but were established before implementation of this Appendix, may be used where documented.

(b) Define the level of testing required prior to and after replacement, repair, modification, or maintenance activities per [IV-3520](#).

(c) Specify the limiting value(s) of full-stroke time of each valve per [IV-3420](#).

(d) Determine if the risk ranking approach per [IV-3800](#) will be used to implement this Appendix.

IV-2000 SUPPLEMENTAL DEFINITIONS

AOV functional margin: the increment or percentage by which an AOV is available as tested capability exceeds the thrust/torque load required to operate the AOV under worst-case operating conditions (also referred to as field margin or post-test margin).

fail safe: characteristic of a valve and its actuator, which upon loss of actuating energy supply, will cause a valve obturator member to be fully closed, fully open, or remain in the last position, as necessary to satisfy the specific function as defined in [ISTA-1100](#).

fail safe test: a test of an AOV with fail-safe functions, performed by observing the operation of the actuator upon loss of valve actuating power.

inservice test value(s): measured parameters that consist of inservice performance assessment test, inservice stroke test, and leak test results.

performance assessment test: performance testing (as defined in [ISTA-2000](#)) consisting of the measurement and assessment of applicable test parameters. This test is normally performed at ambient conditions without system pressure or flow.

pneumatically operated valve (AOV): a valve and its associated actuator, including pneumatically operated PORVs as defined in [ISTC-2000](#), that uses air/gas as the motive force, including all subcomponents required for the valve assembly to perform its specific function as defined in [ISTA-1100](#), except those exempted by [IV-1300](#). For simplicity, this type of valve is referred to as an AOV throughout this Appendix.

stroke test: exercising (as defined in [ISTA-2000](#)) the AOV by operating one complete open and close cycle and testing that includes a full-stroke time (as defined in [ISTC-2000](#)).

test parameter(s): parameters, or combination of parameters, which may be determined from data obtained during testing and are important to monitor to ensure the specific functional capability of the valve assembly. This includes, for example, bench set, spring preload, spring rate, full-stroke time, valve travel, total friction (which is the sum of packing friction, valve internal friction, and actuator friction), torque, thrust, seat load,

¹This Appendix contains requirements to augment the rules of Subsection [ISTC](#).

maximum available pneumatic pressure, and minimum pneumatic pressure required to accomplish the specific function(s) of the valve assembly as defined in [ISTA-1100](#).

IV-3000 GENERAL TESTING REQUIREMENTS

IV-3100 Reserved

IV-3200 Reserved

IV-3300 Preservice Testing

Each AOV shall be tested during the preservice test period as required by this paragraph. These tests shall be conducted under conditions as near as practicable to those expected during subsequent inservice testing. Testing that meets the requirements of this Appendix but was performed before implementation of this Appendix may be used.

Each of the following tests shall be performed for each AOV during the preservice period:

- (a) a performance assessment test
- (b) a stroke test
- (c) a fail safe test, if applicable
- (d) leak testing in accordance with [ISTC-3600](#) and [ISTC-5000](#), as applicable
- (e) position verification testing, for valves with remote position indicators, in accordance with [ISTC-3700](#)

Only one preservice test of each valve is required with the exception that any AOV that has undergone maintenance that could affect its performance after the preservice test shall be tested in accordance with [IV-3520](#).

IV-3400 Inservice Testing

Inservice testing shall commence when the AOV is required to be operable to fulfill its specific function(s) as defined in [ISTA-1100](#) and shall be sufficient to assess changes in AOV functional margin consistent with [IV-6400](#). These tests shall be conducted under conditions as near as practicable to those expected during subsequent inservice testing. Each of the following tests shall be performed for each AOV:

- (a) a performance assessment test in accordance with [IV-3410](#)
- (b) a stroke test in accordance with [IV-3420](#)
- (c) a fail safe test in accordance with [IV-3430](#)
- (d) leak testing in accordance with [ISTC-3600](#) and [ISTC-5000](#), as applicable
- (e) position verification testing, for valves with remote position indicators, in accordance with [ISTC-3700](#), as applicable

IV-3410 Performance Assessment Testing. Performance assessment testing shall be performed as follows:

- (a) For pre-2000 plants, an initial performance assessment test shall be performed within three refueling cycles or 5 yr (whichever is longer) following implementation of

this Appendix to assess functional margin. For post-2000 plants, an initial performance assessment test shall be performed to assess functional margin prior to plant startup or during plant startup activities. The preservice performance assessment test may be used to meet this requirement. In addition, activities that were performed as part of a plant's legacy AOV Program can be used to satisfy the initial performance assessment test provided the requirements of [IV-1400\(a\)](#) have been met and the basis is documented.

(b) The interval for periodic performance assessment tests shall be determined in accordance with [IV-6400](#). If insufficient test data exist from an applicable AOV or AOV group to determine the performance assessment test interval in accordance with [IV-6400](#), then performance assessment testing shall be conducted every three refueling cycles or 6 yr (whichever is longer) until sufficient data exist, from an AOV or AOV group, to justify a longer inservice test interval.

(c) AOVs may be grouped for periodic performance assessment testing as described in [IV-3600](#).

(d) If maintenance activities are scheduled concurrent with an AOV's periodic performance assessment test, then the performance assessment test shall be conducted prior to the maintenance activity, where practicable. See [IV-3520](#) for guidance on the effects of AOV replacement, repair, modification, or maintenance.

(e) For AOVs that operate in the course of plant operation, periodic performance assessment testing, other than the initial test per [IV-3410\(a\)](#), may be satisfied by the following, provided that:

- (1) The conditions during exercise of the AOV meet or exceed the worst-case operating conditions.
- (2) The required observations are made and analyzed during such operation and recorded in the plant record.
- (3) The observation is performed at least once every 24 months.
- (4) The valve exhibits the required change in obturator position.

(5) A stroke test can be performed quarterly.

Credit may be taken for operation at less than design conditions with proper justification. The basis shall be documented by engineering evaluation. The engineering evaluation shall be reviewed and updated, as required, if an AOV application is changed, the AOV is physically modified, or the system is modified in a manner that invalidates the evaluation.

(f) Alternative risk-informed performance assessment test intervals may be applied in accordance with [IV-3800](#).

(g) The periodic performance assessment test interval shall not exceed 10 yr for each AOV.

(h) Any abnormality or erratic action shall be recorded (see [IV-9000](#)), and an evaluation shall be made regarding a need for corrective action.

(i) The Owner shall consider more frequent performance assessment testing for AOVs in any of the following categories:

- (1) AOVs with severe service conditions (temperature, radiation, fluid process, etc.)
- (2) AOVs with any abnormal characteristics (operational, design, or maintenance conditions)
- (3) AOVs with low margin according to the Owner's program

IV-3420 Stroke Testing. Stroke testing shall be performed as follows:

(a) All AOVs, within the scope of this Appendix, shall have a stroke test performed quarterly if practicable as follows:

- (1) Stroke test valves during operation at power to the position(s) are required to fulfill its function(s) in accordance with [ISTA-1100](#).
- (2) If the testing is not practicable during operation at power, it may be limited to testing during cold shutdowns.
- (3) If the testing is not practicable during operation at power or cold shutdown, it may be limited to testing during refueling outages.
- (4) For test intervals of cold shutdown or refueling, testing is not required if the time period since the previous test is less than 3 months. During extended shutdowns, valves that are required to perform their specific function as defined in [ISTA-1100](#) shall be tested every 3 months, if practicable.
- (5) Testing during cold shutdown shall commence within 48 hr of achieving cold shutdown and continue until all testing is complete or the plant is ready to return to operation at power. For extended outages, testing need not be commenced in 48 hr, provided all valves required to be tested during cold shutdown will be tested before or as part of plant start-up.
- (6) All testing required to be performed during a refueling outage shall be completed before returning the plant to operation at power.

(b) Stroke testing includes stroke time measurement as follows:

- (1) The limiting value(s) of full-stroke time of each valve shall be specified by the Owner.
- (2) The stroke time of all valves shall be measured to, at least, the nearest second.
- (3) Any abnormality or erratic action shall be recorded (see [IV-9000](#)), and an evaluation shall be made regarding a need for corrective action.
- (4) Where [IV-3410\(e\)](#) is used to validate valve function, a stroke test shall be performed quarterly.

(c) Stroke testing should be performed prior to performance assessment testing when these tests are scheduled concurrently. This action ensures that the stroke test and its associated trendable parameters are performed under repeatable conditions to the extent practicable.

(d) Valve obturator movement shall be determined in accordance with [ISTC-3530](#).

(e) See [IV-7100](#) for acceptance criteria.

IV-3430 Fail Safe Test. All AOVs with fail-safe actuators, within the scope of this Appendix, shall have a fail safe test performed in accordance with the frequency of [IV-3420\(a\)](#). The fail safe test is performed by observing the operation of the actuator upon loss of valve actuating power.

IV-3500 Test Parameters

IV-3510 Inservice Stroke Test Reference Values. For post-2000 plants (as defined in [Subsection ISTA](#)) or new (i.e., new or replaced) AOVs in pre-2000 plants (as defined in [Subsection ISTA](#)), inservice stroke test reference values shall be determined from the results of preservice testing. For pre-2000 plants, inservice stroke test reference values may be determined from the results of inservice testing. These tests shall be performed under conditions as near as practicable to those expected during subsequent inservice testing. Reference values shall be established only when the valve is known to be operating acceptably. If the particular parameter being measured can be significantly influenced by other related conditions, then these conditions shall be analyzed.

IV-3520 Effect of AOV Replacement, Repair, Modification, or Maintenance. When an AOV is replaced, repaired, modified, or undergoes maintenance that could affect the valve's performance, new inservice test values shall be determined, the previously established inservice test values shall be reconfirmed, or the activities performed shall be evaluated along with the results of post-replacement/repair/modification/maintenance testing to determine if new inservice test values are warranted before the AOV is returned to service. If the AOV was not removed from service, inservice test values shall be immediately determined or confirmed. This testing is intended to demonstrate that test parameters, which could be affected by the replacement, repair, modification, or maintenance, are within acceptable limits. The Owner's program shall define the level of testing required prior to and after replacement, repair, modification, or maintenance activities. Other attributes, such as functional margin, may be considered when defining the level of testing required prior to and after replacement, repair, modification, or maintenance activities, where the basis is properly justified and documented by an engineering evaluation. Deviations between the previous and new inservice test values shall be identified and analyzed. Verification that the new inservice test values represent acceptable operation shall be documented as described in [IV-9000](#).

IV-3530 Establishment of Additional Set of Inservice Stroke Test Reference Values. If it is necessary or desirable for some reason, other than stated in [IV-3520](#), to establish additional stroke test reference values, an inservice stroke test shall first be run at the conditions of an existing set of reference values, or, if impractical, at the conditions for which the new reference values are required, and the results analyzed. If operation is acceptable in accordance with the applicable requirements of [IV-7000](#), a second test shall be performed under the new conditions as soon as practicable. The results of the second test shall establish the additional reference values. Whenever additional reference values are established, the basis shall be justified and documented in the record of tests (see [IV-9000](#)).

IV-3600 Grouping of AOVs for Performance Assessment Testing

AOVs may be grouped for periodic performance assessment testing. Grouping AOVs shall be documented and justified by an engineering evaluation, alternative testing techniques, or both. The following shall be satisfied when grouping AOVs:

(a) AOVs with identical or similar actuators and valves with similar plant service conditions may be grouped together.

(b) Test results shall be evaluated for all AOVs in the group.

(c) All valve assemblies in a group shall have inservice performance assessment testing performed within the maximum test interval.

(d) The number of valve assemblies tested from each group shall be determined using appropriate statistical methodology.

(e) The same valve assembly shall not be selected for the periodic performance assessment test consecutively for a group.

IV-3700 Reserved

IV-3800 Risk-Informed AOV Inservice Testing

Risk-informed AOV inservice testing that incorporates risk insights in conjunction with functional margin to establish AOV grouping, acceptance criteria, exercising requirements, and testing intervals may be implemented.

IV-3810 Risk-Informed Considerations. The Owner shall perform the following when incorporating risk insights in the inservice testing of AOVs:

(a) develop an acceptable risk basis for AOV risk determination

(b) develop AOV screening criteria to determine each AOV's contribution to risk

(c) finalize risk category by a documented engineering evaluation from a Plant Expert Panel

(d) review PRA changes and/or plant modeling changes and apply to risk ranking as applicable

IV-3820 Risk-Informed Methodology. Each AOV shall be evaluated and categorized using a documented risk ranking methodology. [Subsection ISTE](#) provides an acceptable method of risk ranking that may be used to categorize AOVs.

This Appendix provides test requirements for High and Low Safety Significant Component (HSSC/LSSC) categories. If an Owner established more than two risk categories, then the Owner shall evaluate the intermediate SSCs and select HSSC or LSSC test requirements for those intermediate SSCs.

IV-3821 HSSC AOVs. HSSC AOVs shall be tested as follows:

(a) An initial performance assessment test shall be performed to assess functional margin. The preservice performance assessment test may be used to meet this requirement.

(b) Periodic performance assessment testing, in accordance with [IV-3410](#), is required for HSSC AOVs except for AOVs that meet the requirements of [IV-3410\(e\)](#).

(c) Inservice testing shall be performed in accordance with [IV-3400\(b\)](#) through [IV-3400\(e\)](#), as applicable.

(d) Requirements of [IV-3520](#) shall be utilized for AOV replacement, repair, modification, or maintenance.

IV-3822 LSSC AOVs. LSSC AOVs shall be tested as follows:

(a) Inservice testing shall be performed in accordance with [IV-3400\(b\)](#) through [IV-3400\(e\)](#), as applicable.

(b) Requirements of [IV-3520](#) shall be utilized for AOV replacement, repair, modification, or maintenance.

IV-4000 RESERVED

IV-5000 PERFORMANCE ASSESSMENT TEST METHODS

IV-5100 Performance Assessment Test Prerequisites

All testing shall be conducted in accordance with plant-specific technical specifications, installation details, acceptance criteria, and maintenance, surveillance, operation, or other applicable procedures.

IV-5200 Performance Assessment Test Conditions

Performance assessment test conditions shall be sufficient to determine the AOV's functional margin per [IV-6400](#). Test conditions shall be recorded for each test per [IV-9000](#).

IV-5300 Performance Assessment Testing Limits and Precautions

Performance assessment testing limits and precautions include the following:

(a) Manufacturer or vendor limits and precautions associated with the AOV and with the test equipment shall be considered.

(b) Plant-specific operational precautions, design precautions, operational limits, and design limits shall be followed. Items to be considered shall include, but are not limited to, water hammer and intersystem relationships.

(c) The benefits of performing a particular test should be balanced against the potential increase in risk for damage caused to the AOV by the particular testing performed.

IV-5400 Performance Assessment Test Documents

Approved plant documents shall be established for all performance assessment tests specified in this Appendix and shall provide for the following:

(a) methodical, repeatable, and consistent performance testing

(b) collection of performance assessment data required to analyze and evaluate the AOV functional margin in accordance with IV-6400, where applicable

IV-5500 Performance Assessment Test Parameters

Sufficient performance assessment test parameters shall be selected for measurement to meet the requirements of IV-6000.

IV-6000 PERFORMANCE ASSESSMENT TEST ANALYSIS AND EVALUATION

IV-6100 Performance Assessment Test Acceptance Criteria

Acceptance criteria shall be established for applicable AOVs within the scope of this Appendix. Applicable test parameters (as defined in IV-2000) shall be used.

Instrumentation and test equipment accuracy shall be considered in accordance with ISTA-4000 when establishing the test acceptance criteria.

Acceptance criteria shall be reviewed and updated, as required, if an AOV application is changed, the AOV is physically modified, or the system is modified in a manner that invalidates the acceptance criteria.

IV-6200 Performance Assessment Test Data Analysis

Data obtained from a test required by this Appendix shall be analyzed to determine if the AOV performance is acceptable. The Owner shall determine which methods are suitable for analyzing tested parameters for each AOV and provide the necessary instructions for performance of the analyses.

Whenever data are analyzed, all relevant operating and test conditions shall be considered.

The Owner shall compare performance test data to the acceptance criteria.

Performance assessment test data analysis shall include a qualitative review to identify anomalous behavior. If indications of anomalous behavior are identified, the cause of the behavior shall be analyzed and corrective actions completed, if required, in accordance with IV-6500.

IV-6300 Performance Assessment Test Data Evaluation

The Owner shall determine which methods are suitable for evaluating performance assessment test data for each AOV and application.

The Owner shall develop procedural guidelines to establish the methods and timing for evaluating AOV performance assessment test data.

Where periodic performance assessment testing is being performed, evaluations shall determine the loss of functional margin that occurred over time and shall consider the influence of past maintenance and test activities to establish appropriate frequencies for future performance assessment test activities.

IV-6400 Performance Assessment Test Determination of AOV Functional Margin

Where periodic performance assessment testing is being performed, the Owner shall demonstrate that adequate functional margin exists between valve operating requirements and the available actuator output capability to satisfy the acceptance criteria (IV-6100). In addition to meeting the acceptance criteria, the performance assessment test interval, as required by IV-3410, shall be set such that adequate functional margin shall exist to provide reasonable assurance that changes in AOV-operating characteristics over time do not result in reaching a point at which the acceptance criteria are not satisfied before the next scheduled test activity.

IV-6500 Performance Assessment Test Corrective Action

If the AOV performance is unacceptable, as established in IV-6200, corrective action shall be taken in accordance with Owner's corrective action requirements.

IV-7000 STROKE TEST AND FAIL SAFE DATA ANALYSIS AND EVALUATION

IV-7100 Stroke Test Acceptance Criteria

Test results shall be compared to the reference values established in accordance with [IV-3510](#), [IV-3520](#), and [IV-3530](#).

(a) Valves with reference stroke times of greater than 10 sec shall exhibit no more than $\pm 25\%$ change in stroke time when compared to the reference value.

(b) Valves with reference stroke times of less than or equal to 10 sec shall exhibit no more than $\pm 50\%$ change in stroke time when compared to the reference value.

(c) Valves that stroke in less than 2 sec may be exempted from (b). In such cases, the maximum limiting stroke time shall be 2 sec.

Instrumentation and test equipment accuracy shall be considered in accordance with [ISTA-4000](#).

IV-7200 Stroke Test and Fail Safe Corrective Action

If a valve fails to exhibit the required change of obturator position or exceeds the limiting values of full stroke time [see [IV-3420\(b\)\(1\)](#)], the valve shall be immediately declared inoperable.

Valves with measured stroke times that do not meet the acceptance criteria of [IV-7100](#) shall be immediately retested or declared inoperable. If the valve is retested and the second set of data also does not meet the acceptance criteria, the data shall be analyzed within 96 hr to verify that the new stroke time represents acceptable valve operation, or the valve shall be declared inoperable.

If the second set of data meets the acceptance criteria, the cause of the initial deviation shall be analyzed and the results documented in the record of tests (see [IV-9000](#)).

Valves declared inoperable may be repaired or replaced or the data may be analyzed to determine the cause of the deviation and the valve shown to be operating acceptably.

Valve operability based upon analysis shall have the results of the analysis recorded in the record of tests (see [IV-9000](#)).

See [IV-3520](#) for guidance on returning a repaired or replacement valve to service.

IV-8000 RESERVED

IV-9000 RECORDS AND REPORTS

IV-9100 Records

The Owner shall maintain a record that shall include the following:

(a) records as required by [ISTA-9000](#) and [ISTC-9000](#)

(b) documentation showing that legacy AOV program activities met requirements within this Appendix, if used to satisfy [IV-3410\(a\)](#)

(c) documentation of engineering evaluation per [IV-3410\(e\)](#)

(d) any abnormal or erratic action in accordance with [IV-3410](#) and [IV-3420](#)

(e) documentation of engineering evaluation as applicable per [IV-3520](#)

(f) risk ranking methodology and finalized risk category from a Plant Expert Panel as documented in an engineering evaluation per [IV-3810](#) and [IV-3820](#)

(g) documentation of performance assessment test acceptance criteria per [IV-6100](#)

(h) summary of analysis, evaluation, and functional margin required per [IV-6200](#), [IV-6300](#), [IV-6400](#), and [IV-7000](#)

IV-9200 Test Plans

The Owner shall maintain a record of test plans that shall include the following:

(a) test plans as required by [ISTA-9000](#) and [ISTC-9000](#)

(b) values of test data, parameters, and information established by [IV-5000](#)

(c) performance assessment test methods and conditions, described in [IV-5000](#), including description of valve lineups, process equipment, and type of test

(d) test plans when grouping AOVs in accordance with [IV-3600](#)

Division 1, Nonmandatory Appendix A¹

Preparation of Test Plans

A-1000 PURPOSE

The purpose of this Appendix is to provide guidance for the preparation of test plans to ensure adequate information for submittal to reviewing agencies. This Appendix is not part of [Subsection ISTA](#) but is included for informational purposes.

A-2000 TEST PLAN CONTENTS

A-2100 Background and Introduction

Test plans, which may consist of one or more parts (e.g., a part for general information and parts with details), should include the following:

- (a) dates of test interval
- (b) the edition and addenda of this Subsection used
- (c) Code classification of components and boundaries of system classification including
 - (1) specific rules for classification
 - (2) lists of systems and identification of acronyms used
- (d) summary tables for each system showing Code classification, type of components, and tests or examinations to be performed
- (e) the Code requirements for each component that are not being satisfied by the tests or examinations, and justification for the substitute tests or examinations as discussed in [A-3000](#)
- (f) Code Cases proposed for use and the extent of their application
- (g) a reference list of applicable documents, as required by [A-2300](#)
- (h) names, signatures, and company affiliation of the preparers and approvers of the test plan

A-2200 Summary of Changes in Updated Test Plans

The following summary information should be included to describe changes in updated test plans:

- (a) listing of new or revised procedures
- (b) changes in exemptions, tests, or examinations
- (c) changes in substitute tests or examinations of [A-3000](#)

A-2300 Applicable Documents

Test plans should include a reference list of applicable documents. The following documents should be considered:

- (a) 10 CFR 50
- (b) edition and addenda of this Subsection that apply (if portions of different editions or addenda are selected, identify the related requirements and components selected for testing or examination for each edition and addenda)
- (c) Code Cases
- (d) other regulatory documents
- (e) piping and instrument diagrams (P&IDs)

A-2400 Code Subsections

- (a) Test plans should address the following Subsections:
 - (1) ISTB, pumps
 - (2) ISTC, valves
 - (3) ISTD, dynamic restraints (snubbers)
- (b) Plans for Subsections may be combined in whole or part and published as one plan or as separate plans.

A-2500 Detailed Contents

- (a) Test plans should include the following:
 - (1) specific exemptions applied to each system covered by this Subsection
 - (2) list of components, including system identification, Code classification, and nominal size
 - (3) tables that provide details of tests or examinations (typical information to be included in these tables is shown in Supplements 1 through 3)
 - (4) a list of test and examination procedures including identification, titles, and general description of the components to which each procedure is applicable
- (b) Test plans need not include valves that have no test requirements.

¹ This Appendix is included for informational purposes only. While it is related to [Subsection ISTA](#), it is not part of that Subsection.

A-3000 SUBSTITUTE TESTS AND EXAMINATIONS

A-3100 General

The following should be used when any Code requirement is not being satisfied by planned tests or examinations and when substitute tests or examinations² are included in the test plan.

A-3200 Justification of Substitute Tests and Examinations

Justification of substitute tests and examinations should include the following:

- (a) Code Class
- (b) Code test or examination requirements and identification of individual components for which substitute test or examinations are planned
- (c) identification of the substitute tests or examinations that are planned
- (d) frequency or schedule, as applicable, for the planned substitute tests or examinations including any plans for deferring the required tests or examinations
- (e) documentation (drawings, sketches, or photographs may be used) of reasons the required tests or examinations are impractical, such as

- (1) system or plant operating limitations
- (2) inaccessibility
- (3) equipment design
- (4) radiation levels at the test or examination area
- (5) total estimated man-REM exposure involved in the test or examination
- (6) flushing or shielding capabilities that might reduce radiation levels
- (7) considerations involving remote examination
- (f) technical justification and data to support the substitute tests or examinations, including
 - (1) description and justification of any changes expected in the overall level of plant quality and safety by performing the proposed substitute tests or examinations in lieu of the Code requirements
 - (2) identification and discussion of similar components (in redundant systems or in the same system) to be tested or examined as substitutes
 - (3) percentage of the required tests or examinations that have been or will be completed on each component for which substitute tests or examinations are planned
 - (4) discussion of the consequences of failure of the component for which the substitute tests or examinations are planned

²Substitute tests or examinations are tests or examinations that replace Code-required tests or examinations when the Code requirements are considered to be impractical.

Division 1, Supplement to Nonmandatory Appendix A

AS-1000 SUPPLEMENT 1: INFORMATION FOR ISTB PUMP TEST TABLES

- (a) identification of system, in system-by-system order
- (b) Code classification
- (c) identification of specific pumps to be tested
- (d) reference to drawings locating the pumps
- (e) identification of specific tests to be performed, such as speed, flow rate, pressure, and vibration
- (f) test frequency or schedule, as applicable
- (g) reference to Code requirements that are not being satisfied, and identification of substitute tests

AS-2000 SUPPLEMENT 2: INFORMATION FOR ISTC VALVE TEST TABLES

- (a) identification of systems, in system-by-system order
- (b) Code classification
- (c) identification of specific valves to be tested
- (d) reference to drawings locating the valves
- (e) valve category and size
- (f) specific information on the valves to be tested, including valve type, actuator type, normal position, stroke direction, test to be performed, plant operational mode at the time of test, and maximum stroke time

- (g) test frequency or schedule, as applicable
- (h) reference to Code requirements that are not being satisfied, and identification of substitute tests

AS-3000 SUPPLEMENT 3: INFORMATION FOR ISTD DYNAMIC RESTRAINT (SNUBBER) TABLES

- (a) identification of systems, in system-by-system order
- (b) Code classification
- (c) individual dynamic restraints (snubbers) selected for test and examination
- (d) reference to drawings locating dynamic restraints (snubbers)
- (e) acceptance criteria for the tests and examinations
- (f) test or examination methods
- (g) test or examination frequency or schedule, as applicable
- (h) reference to Code requirements that are not being satisfied, and identification of substitute tests or examinations

Division 1, Nonmandatory Appendix B¹

Dynamic Restraint Examination Checklist Items

B-1000 PURPOSE

The purpose of this Appendix is to provide examples of items normally included in a checklist used to verify preservice and inservice examination requirements. This Appendix is not part of [Subsection ISTD](#) but is included for informational purposes.

B-2000 EXAMPLES FOR PRESERVICE AND INSERVICE

Some examples of unacceptable attributes normally included in a checklist to verify preservice and inservice examination requirements are as follows:

- (a) inadequate reservoir fluid level
- (b) loose, missing, or incorrectly installed structural connections or fasteners
- (c) vented reservoir oriented such that hydraulic fluid cannot gravitate to snubber
- (d) corrosion or solid deposits that could result in unacceptable snubber performance
- (e) deformed structural attachment or piston rod

(f) weld arc strikes, paint, weld slag, adhesive, or other deposits on piston rod or support cylinder that could result in unacceptable snubber performance

(g) spherical bearing not fully engaged in attachment lug

(h) inadequate position setting

B-3000 EXAMPLES FOR PRESERVICE ONLY

Some examples of additional unacceptable attributes normally included in a checklist to verify preservice examination requirements only are as follows:

- (a) incorrect snubber load rating
- (b) incorrect installed location
- (c) incorrect installed orientation
- (d) incorrect position setting
- (e) incorrect snubber configuration
- (f) inadequate swing clearance
- (g) snubber installed with preset locking screws used for shipment only
- (h) protective coverings or shipping plugs not removed

¹ This Appendix is included for informational purposes only. While it is related to [Subsection ISTD](#), it is not part of that Subsection.

Division 1, Nonmandatory Appendix C¹

Dynamic Restraint Design and Operating Information

C-1000 PURPOSE

The purpose of this Appendix is to provide guidance in the form of design and operating information, which may be useful in the development of inservice programs for snubbers. This Appendix is not part of [Subsection ISTD](#) but is included for informational purposes.

C-2000 DESIGN AND OPERATING ITEMS

Some items of snubber design and operating information that may be useful in the development of an inservice program are as follows:

- (a) snubber operation and maintenance instructions including parts list
- (b) design drawings showing snubber rating, location, orientation, pin-to-pin dimensions, and hot and cold settings
- (c) procurement specifications

- (d) snubber qualification and acceptance test results
- (e) snubber application reports
- (f) the desired reservoir fluid level as a function of piston location and spatial orientation
- (g) the correlation of activation velocity, acceleration, and release rate at normal test temperatures to the range of operating temperatures expected so that the snubber may be normalized at test temperature to perform within a specified range when at its operating temperature
- (h) method for measuring the position setting
- (i) required fluid and seal material specification
- (j) limiting environmental conditions affecting service
- (k) drag force for each size and type snubber furnished
- (l) the correlation of hydraulic snubber release rate at various loads and the acceleration limiting value of mechanical snubbers at various loads to justify testing at less than rated loads

¹ This Appendix is included for informational purposes only. While it is related to [Subsection ISTD](#), it is not part of that Subsection.

Division 1, Nonmandatory Appendix D¹

Comparison of Sampling Plans for Inservice Testing of Dynamic Restraints

D-1000 PURPOSE

The purpose of this Appendix is to provide information to enable the user to make comparisons of the sampling plans included in Subsection ISTD. This Appendix is not part of [Subsection ISTD](#) but is included for informational purposes.

D-2000 DESCRIPTION OF THE SAMPLING PLANS

For simplicity, sampling plans are referred to as the 10% plan and the 37 plan.

D-2100 The 37 Plan

The 37 plan has an “accept” line. The accept line is represented by the equation

$$N = 36.49 + 18.18C$$

where

C = number of unacceptable snubbers
 N = number of snubbers tested

If the point plotted falls on or below the accept line, as shown in [Subsection ISTD, Figure ISTD-5431-1](#), testing of that group may be discontinued. If the accept region still has not been reached after testing between 100 and 200 snubbers, then the actual percent of population quality (C/N) should be used to indicate the probability of extended or 100% testing. A population quality of $\geq 5\%$ failed snubbers will probably result in extended testing.

D-2200 The 10% Plan

The 10% plan is really a family of “accept” lines that follow the equation

$$N = 0.1n(1 + C/2)$$

where

n = the number of snubbers in the test population

The treatment of each “accept” line is the same as in the 37 plan.

D-3000 COMPARISON OF SAMPLING PLANS

To cover the wide range of numbers of snubbers and acceptable population quality expected in different plants, two sampling plans are permitted. Both sampling plans provide the required protection. Therefore, the selection of a plan may be based on the number of tests required without compromising safety. The group size effect for the two plans is specified in [D-3100](#) and [D-3200](#).

D-3100 Up to 370 Snubbers

The 10% plan requires the least testing for smaller groups. For groups up to 370 snubbers, the 10% plan is preferred because less testing is required. Note that for a group of 370 snubbers, the 10% plan and the 37 plan both require the same number of tests.

D-3200 Above 370 Snubbers

For groups that have more than 370 snubbers, the 37 plan is preferred to the 10% plan. In this range, the 37 plan requires less testing than the 10% plan.

¹ This Appendix is included for informational purposes only. While it is related to [Subsection ISTD](#) it is not part of that Subsection.

Division 1, Nonmandatory Appendix E¹

Flowcharts for 10% and 37 Snubber Testing Plans

E-1000 PURPOSE

This Appendix presents the testing plans in a flowchart form to enable the user to understand the options available for the corrective actions when unacceptable snubbers are found (see [Figures E-1000-1](#) and [E-1000-2](#)).

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¹ This Appendix is included for informational purposes only. While it is related to [Subsection ISTD](#), it is not part of that Subsection.

Figure E-1000-1
Flowchart for 10% Snubber Testing Plan (ISTD-5300)

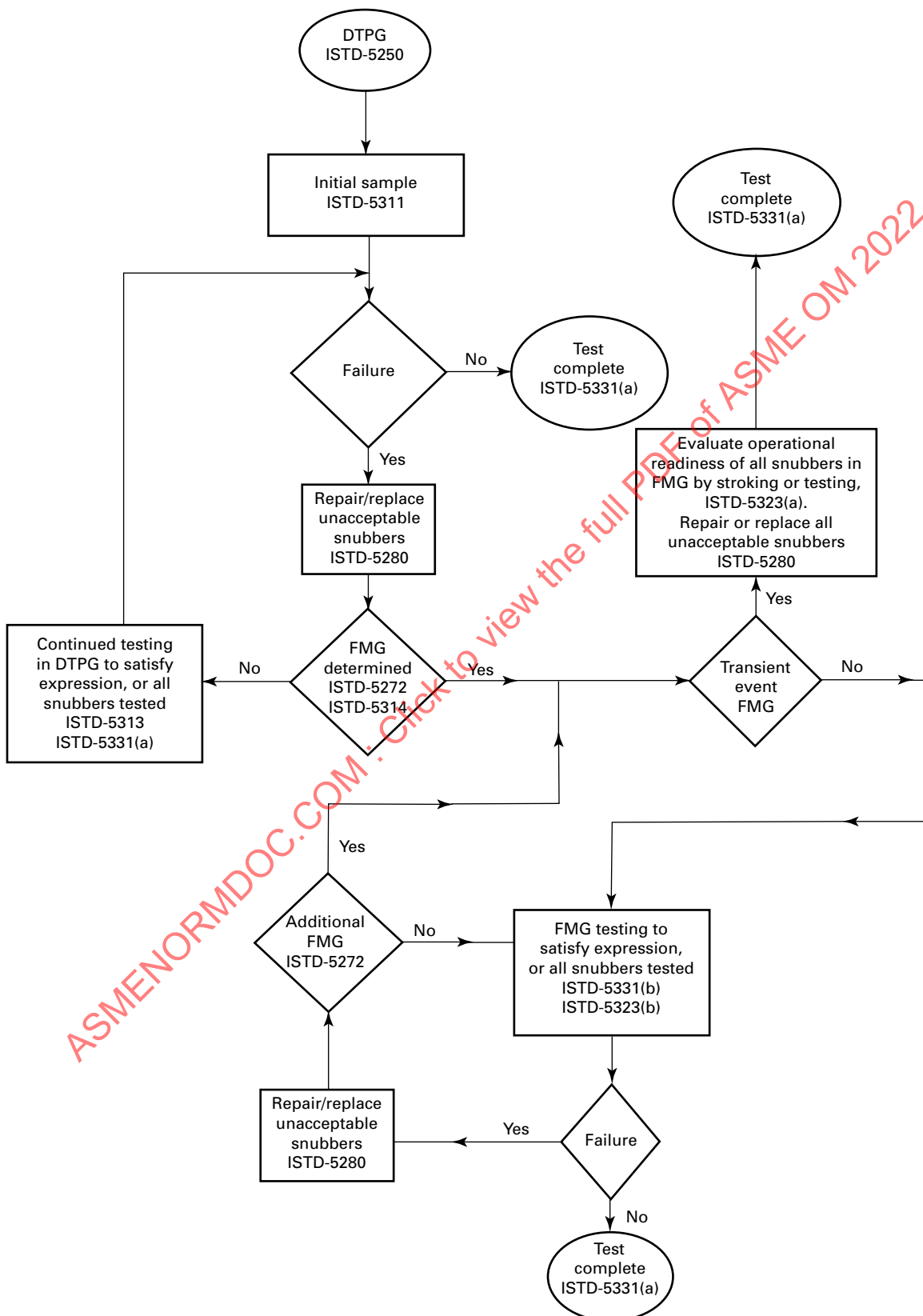
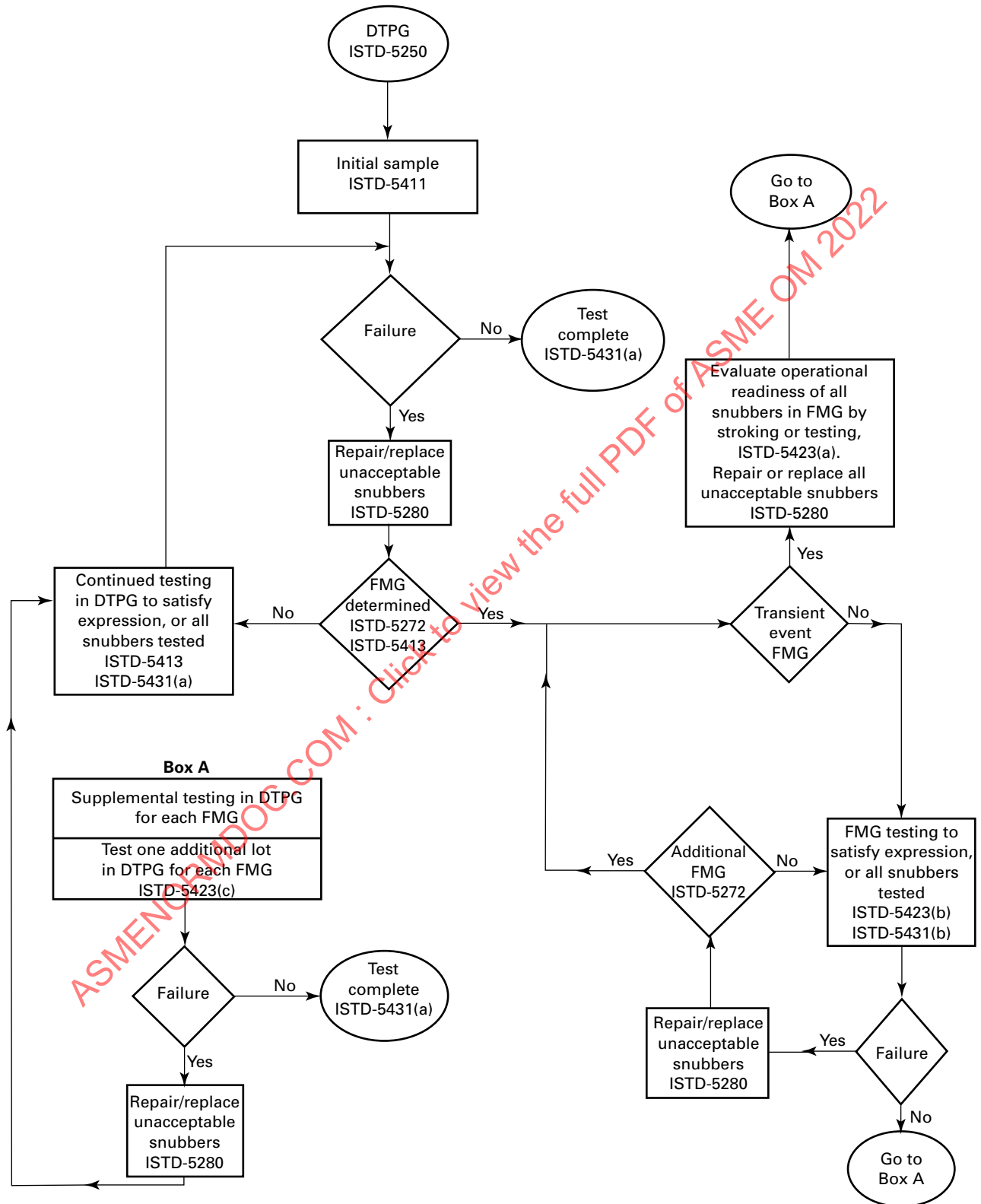


Figure E-1000-2
Flowchart for 37 Snubber Testing Plan (ISTD-5400)



Division 1, Nonmandatory Appendix F¹

Dynamic Restraints (Snubbers) Service Life Monitoring Methods

F-1000 PURPOSE

Degradation due to service environment and maintenance errors can adversely affect snubber performance. This Appendix discusses methods and considerations that can be used to predict and reevaluate snubber service life to optimize snubber availability during plant operation. The service life monitoring program should be based on knowledge of the operating environment, snubber design limits, and service records.

F-2000 PREDICTED SERVICE LIFE

Before start of service, snubber service life should be conservatively predicted, based on manufacturer recommendations or design review.

F-2100 Manufacturer Recommendations

Manufacturer recommendations may include seal and fluid replacement intervals for hydraulic snubbers or intervals for replacement of critical parts and/or lubricant for mechanical snubbers. Such intervals may vary, depending upon the application.

F-2200 Design Review

Snubber design review should consider materials, design features, and the plant operating environment. Evaluation of the effects of the environment on critical snubber parts such as seals, hydraulic fluids, lubricants, platings, etc., should be particularly emphasized.

F-3000 SERVICE LIFE REEVALUATION

Service life reevaluation should include the considerations discussed in F-3100 through F-3320.

F-3100 Knowledge of the Operating Environment

Actual plant operating environments can differ significantly from original plant design specifications. Some snubbers may be subjected to localized high temperatures that are not representative of the general snubber population. Such applications may require augmented inspections or more frequent snubber overhaul or replacement than originally predicted.

On the other hand, the operating environment for the majority of snubbers may be significantly less severe than described in plant design specifications. Unnecessary overhaul or replacement of such snubbers may increase the incidence of snubber failure by introducing handling or maintenance errors.

It is important, therefore, that the operating environment be identified and an appropriate service life established. Environmental parameters may include the following:

- (a) temperature
- (b) vibration
- (c) transient loading
- (d) radiation
- (e) humidity
- (f) airborne contaminants
- (g) leakage of adjacent components

Severe environments may be identified by plant operating data, direct measurement of environmental parameters, evaluation of the installed location [e.g., proximity to high-temperature components, or by examination of snubbers (or snubber parts)].

F-3110 Direct Measurement of Environmental Parameters. Various types of instrumentation and equipment are available for direct measurement of environmental parameters such as temperature, vibration, radiation, and humidity. Such equipment may be used for specific snubber locations where severe environments are expected or as an aid in determining the cause of snubber degradation.

F-3120 As-Found Testing. As-found testing of snubbers removed from service can identify degradation due to severe operating environments.

F-3200 Knowledge of Operating Environment Effects

Reevaluation of a snubber service life should include a thorough knowledge of the effects of various operating environments on snubber performance. Such knowledge may not be readily available from the manufacturer and may require engineering evaluation, including monitoring of trendable degradation parameters for snubbers removed from service. This might include periodic measurement of potentially trendable test parameters, e.g., drag force for selected snubbers. Periodic

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disassembly and evaluation of snubber internal parts (e.g., seals, springs fluid, etc., may also be required).

F-3210 Identification of Degraded Snubbers. Degraded snubbers may often be identified by visual examination of snubbers or snubber parts, by sampling of hydraulic fluid, or by evaluation of functional test data.

F-3220 Trending. The following should be considered for trending:

(a) establishment of trending parameters and associated baseline data

(b) trending parameters should relate directly to the anticipated failure mode

(c) reservoir fluid level is the most appropriate trending parameter for monitoring snubber leakage

(d) trends may be more effectively identified using average rather than peak drag force

F-3300 Cause Evaluation of Degraded or Failed Snubbers

Failures often result from influences not related to service time or service environment. Such influences include maintenance activities, construction activities, and manufacturing defects. It is important to ensure that service life is not unjustifiably influenced by such failures or degradation. Therefore, snubbers that failed in-service examinations or tests, and snubbers removed from service due to excessive degradation, should be evaluated to determine the cause of the degradation or failure.

F-3310 Failure Evaluation Data Sheet. Failure evaluation data sheets should include information pertaining to failure mode, failure mechanism, environment, service

time, abnormal conditions, visual observations, test results, and test observations.

F-3320 Diagnostic Testing. Diagnostic testing may be useful in identifying the failure or degradation mechanism.

F-4000 SHORTENED SERVICE LIFE

It may be necessary to shorten the service life of snubbers subjected to severe environments, such as excessively high temperatures and vibration. Snubbers in severe environments may require augmented surveillance, including "hands-on" evaluations (e.g., stroking or in-situ monitoring).

F-5000 SERVICE LIFE EXTENSION

In many cases, where there has been minimal degradation due to the service environment, it may be appropriate to extend the previously established service life. Service life extension should be based on a technical evaluation of snubber performance that includes the current level of service-related degradation as well as the degradation rate.

F-6000 SEPARATE SERVICE LIFE POPULATIONS

Depending on the significance of environmental extremes from one area in the plant to another, separate and distinct service life populations may be appropriate.

Division 1, Nonmandatory Appendix G¹

Application of Table ISTD-4252-1, Snubber Visual Examination

G-1000 PURPOSE

This Appendix provides guidance for use of Table ISTD-4252-1 to determine subsequent snubber examination interval.

G-3200 Application of Column B

On the 750 population line, if the number of unacceptable snubbers is greater than 20 but less than or equal to 40, referring to Column B and Note (4), the next examination interval is the same as the previous interval (12 months).

G-3300 Application of Less Than or Equal to Column C and Recovery

(22)

If the number of unacceptable snubbers is greater than 40, but less than or equal to 78 (say 60), referring to Columns B and C and Note (5), then interpolation may be used or the interval is reduced to two-thirds of the previous interval. If the previous interval was the 12-month normal fuel cycle, then the next examination interval is $\frac{2}{3} \times 12 = 8$ months. Alternatively, for 60 unacceptable snubbers, interpolate between Columns B and C, i.e., examination interval

$$= \frac{2}{3} \times 12 + \left[\frac{(12 - 8)}{(78 - 40)} \times (78 - 60) \right]$$

$$= 8 + 1.89 = 9.89 \text{ months}$$

However, for determining the subsequent examination interval, use the previous interval as 8 months without interpolation, or 9.89 months when interpolation is used.

The number of unacceptable snubbers found during the subsequent interval will determine the next examination interval as follows:

If the number of unacceptable snubbers is

(a) less than or equal to Column A, the next examination interval is 2×8 months or 2×9.89 months

(b) greater than Column A but less than or equal to Column B, the next examination interval is 8 months or 9.89 months

(c) greater than Column B but less than or equal to Column C, the next examination interval is two-thirds of 8 months or two-thirds of 9.89 months, or interpolate between Columns B and C

G-3400 Application of Table When Number Exceeds Column C

For a population of 750 snubbers, if the number of unacceptable snubbers is greater than 78 (i.e., the number shown in Column C), then the next examination interval is

(22) G-2000 ASSUMPTIONS

The assumptions used are as follows:

(a) snubber population = 750 snubbers installed in the unit

(b) accessible portion of the population = 300

(c) inaccessible portion of the population = 450

(d) normal fuel cycle = 12 months

NOTE: Examination intervals may vary in accordance with Table ISTD-4252-1, Note (2).

G-3000 CASE 1: EXAMINE ACCESSIBLE AND INACCESSIBLE SNUBBERS JOINTLY

If the decision is made to examine the snubber population without categorizing snubbers as accessible or inaccessible in accordance with ISTD-4220, then the total number of snubbers unacceptable to the visual examination requirement is used in Table ISTD-4252-1 to determine the next examination interval.

(22) G-3100 Application of Column A

If the total number of unacceptable snubbers found during the current interval is 20 or less, referring to population line for 750 snubbers and Column A, then, in accordance with Table ISTD-4252-1, Note (3), the next examination interval is twice the previous interval but not greater than 48 months. If the previous examination interval was the normal fuel cycle, the examination during the next cycle may be skipped. Thus, the next examination is due at 24 months with a maximum extension of 6 months. If the number of unacceptable snubbers found at the next examination is equal to or less than the number in Table ISTD-4252-1, Column A, the next interval may be doubled again, but not to exceed a nominal length of 48 months [plus the tolerance per Table ISTD-4252-1, Note (2)].

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two-thirds of the previous interval. If the previous interval was the normal fuel cycle of 12 months, the calculation is $\frac{2}{3} \times 12 = 8$ months.

G-4000 CASE 2: EXAMINE ACCESSIBLE AND INACCESSIBLE SNUBBERS SEPARATELY

If the decision was made to examine the accessible and inaccessible snubbers as separate categories, results are used separately in [Table ISTD-4252-1](#).

G-4100 Determine the Values From Columns A Through C

The values for 300 snubbers are given in [Table ISTD-4252-1](#). However, for the 450 inaccessible snubbers, interpolate to determine the number of unacceptable snubbers for each column. The interpolation may be applied whenever the exact population or category quantity is not given in [Table ISTD-4252-1](#).

Snubbers	Column A	Column B	Column C
300 accessible	5	12	25
450 inaccessible	10	21	42

G-4200 Determine Subsequent Interval Separately

The number of unacceptable snubbers found in the accessible or inaccessible category shall determine the next examination interval for each category separately. The process for each is the same as discussed in [G-3000](#). For example

(a) if the number of unacceptable snubbers in the accessible category is 10 (greater than Column A but less than or equal to Column B), then the next examination interval for the accessible category is the previous interval

(b) if the number of unacceptable snubbers in the inaccessible category is 6 (less than or equal to Column A, which is 10 for 450 snubbers), then the next interval for the inaccessible category is twice the previous interval

G-4300 Recombining Categories Into One Population

If the accessible and inaccessible categories have different intervals for the subsequent examination, they may be examined jointly at the shorter examination interval required by either category. Use the shorter interval as the previous interval in determining the subsequent examination interval for the entire population.

G-4400 10-yr Interval Using [Table ISTD-4252-1](#), [Note \(7\)](#) and [ISTD-4253](#) (22)

An extended interval as specified in [Table ISTD-4252-1](#), [Note \(7\)](#) and [ISTD-4253](#) may be used to extend the examination interval to a maximum of 10 yr. The cumulative number of unacceptable snubbers per [ISTD-4252\(e\)](#) must be tracked during the interval. If at any time during the extended examination interval the cumulative number of unacceptable snubbers exceeds the applicable value from [Table ISTD-4252-1](#), Column B, then the current examination interval shall end and all remaining examinations must be completed within the current fuel cycle. The duration of the subsequent examination interval shall be reduced to the maximum 48-month examination interval used prior to implementing the 10-yr interval. The beginning of the subsequent fuel cycle shall be the starting date for the new examination interval.

Division 1, Nonmandatory Appendix H¹

Test Parameters and Methods

H-1000 PURPOSE

This Appendix provides guidelines for establishing snubber functional test methods that will produce information compatible with [Subsection ISTD](#) requirements. These guidelines do not preclude any particular test equipment or method. Manufacturer recommendations should be considered. EPRI Report No. TR-102363, Evaluation of Snubber Functional Test Methods, July 1993, provides additional guidance.

H-2000 TEST VARIABLES

Snubber functional testing involves three test variables. These variables are force, displacement, and time. All snubber test parameters are measured in terms of one or more of these variables. For example, velocity is measured as change in displacement per unit time, acceleration is measured as change in velocity per unit time.

Snubber functional tests involve measuring at least one of these variables as a dependent variable, while controlling at least one of the other variables.

H-3000 TEST PARAMETER MEASUREMENT

[Subsection ISTD](#) requires measurement of one or more of the following parameters:

- (a) drag force
- (b) activation
- (c) release rate

H-3100 Drag Force Measurement

Drag force is measured by controlling the snubber stroke displacement while measuring the resulting resistance force. Generally, the rate of change in displacement (velocity) is also controlled.

H-3200 Activation Measurement

Activation applies to snubbers that have two distinct operating modes (i.e., activated and inactivated). Activation may involve control valve closure for a hydraulic snubber or engagement of a braking mechanism for a mechanical snubber. The three activation parameters are discussed in [H-3210](#) through [H-3230](#).

H-3210 Locking Velocity. Locking velocity is measured by stroking the snubber at a gradually increasing velocity. Generally, the rate of change in velocity (ramp rate) is also controlled. Locking velocity is determined by recording stroke velocity at the point of control valve closure. Control valve closure may be identified using a number of indicators including the point of sudden force increase.

H-3220 Velocity Threshold. Velocity threshold is measured by stroking the snubber at a velocity sufficient to activate the velocity limiting mechanism. After activation, a specified constant force is applied. Velocity threshold is determined by recording the average stroke velocity over a specified time period or stroke distance, after the force stabilizes at the specified value. This applies to a velocity-limiting device.

H-3230 Acceleration Threshold. Acceleration threshold is measured by stroking at an acceleration sufficient to activate the acceleration limiting mechanism. After activation, a specified force is applied. Acceleration threshold is determined by recording the average acceleration over a specified time period or stroke distance, after the force stabilizes at the specified value. This applies to an acceleration-limiting device.

H-3300 Release Rate Measurement

Release rate is measured by applying a specified constant force to the snubber while measuring the resulting stroke velocity. Release rate is determined by recording the average stroke velocity over a specified time period or stroke distance, after the force stabilizes at the specified value.

H-4000 GENERAL TESTING CONSIDERATIONS

Snubber functional testing may involve the use of more than one test machine. Test results are subject to some variation due to a number of influences, including differences in instrumentation, the magnitude of controlled variables, variations in test machine control methods, environmental influences, and variations in data interpretations.

¹ This Appendix is included for informational purposes only. While it is related to [Subsection ISTD](#), it is not part of that Subsection.

H-4100 Drag Test Velocity

For some snubber models, drag force is sensitive to test velocity. Test velocity should therefore be representative of the anticipated thermal movement rate of the components to which the snubbers are attached. Establishing standard drag test velocities will also facilitate identification of trends.

NOTE: For acceleration-limiting snubbers, the ramp rate (acceleration) to the desired drag test velocity should be maintained at a level that is less than anticipated activation threshold.

H-4200 Test Force

H-4210 Effect on Release Rate. The relationship between release rate and test force is generally consistent and predictable. Release rates measured at any test force can generally be reliably converted to the associated release rate value at the specified test force using empirically derived correlation curves or equations. For example, the release rate of a snubber tested at 60% of rated load may be converted to the corresponding release rate at 100% of rated load.

H-4220 Effect on Activation. Locking velocity is unaffected by test force because the test force is not applied until after activation. Velocity threshold and acceleration

threshold, on the other hand, are measured while applying a force to the snubber. For these parameters, the effect of variations in test force should be established for each snubber model, either for correlation purposes or for verification that the parameter is unaffected by such variations.

H-4300 Velocity Ramp Rate

Locking velocity test results may be affected by velocity ramp rate (the rate of increase of stroke velocity). Results of locking velocity tests conducted at a ramp rate less than 2 in./min/sec will generally be unaffected in this regard.

H-4400 Data Recording

A continuous recording of test variables should be performed. These data will assist in verification of the test results and resolution of any snubber performance anomalies.

H-4500 Verification of Test Results

Some test machines calculate and print test results automatically. Manual verification of automatically generated results will help validate the printouts. See also [H-4400](#).

Division 1, Nonmandatory Appendix J¹

Check Valve Testing Following Valve Reassembly

J-1000 PURPOSE

The purpose of this Appendix is to provide guidance for determining the appropriate post-maintenance testing for check valves discussed in [ISTC-5221\(c\)](#).

J-2000 POSTDISASSEMBLY TEST RECOMMENDATIONS

When a check valve is disassembled and examined because it is impractical to verify it open or close, verifying the proper reassembly of the valve should not require performance of the impractical test. Since an examination is not a test, the test matrix, shown in [Table J-2000-1](#), was developed to help the Owner establish post-maintenance testing requirements. Some of the examples recommend a demonstration of the nonsafety function (e.g., if a valve is

disassembled because closure cannot be demonstrated, then an open test to at least partially open the obturator is recommended). Disassembly and examination activities cannot be used to satisfy a leakage test requirement. If postmaintenance testing is not practicable, the Owner should take other appropriate actions to ensure proper reassembly.

J-3000 TEST MATRIX

The test matrix, shown in [Table J-2000-1](#), provides recommendations for the Owner's use in establishing post-maintenance test requirements. Where multiple recommendations are provided, the recommendations are listed in order of preference.

¹ This Appendix is included for informational purposes only. While it is related to [Subsection ISTC](#), it is not part of that Subsection.

Table J-2000-1
Check Valve Test Matrix

Valve Exercise Requirement	Reason for Disassembly	Postmaintenance Testing Recommendation
Safety Function:		
Open	Cannot achieve flow to fulfill its intended function	1. Perform an open test to partially open the obturator, if practicable 2. If a seat leakage requirement exists, do the leakage test 3. Perform a closure test
Close	Cannot verify closure	Perform an open test to at least partially open the obturator, if practicable
Open and Close	Cannot achieve flow to fulfill its intended function	1. Perform an open test to partially open the obturator, if practicable 2. If a seat leakage requirement exists, do the leakage test 3. Perform a closure test
Open and Close	Cannot verify closure	Perform an open test to at least partially open the obturator, if practicable
Open and Close	Cannot achieve flow to fulfill its intended function, and cannot verify closure	Perform an open test to partially open the obturator, if practicable

Division 1, Nonmandatory Appendix K¹

Sample List of Component Deterministic Considerations

K-1000 PURPOSE

This Appendix provides guidance to the Plant Expert Panel for categorizing components as HSSC or LSSC.

K-2000 SAMPLE DETERMINISTIC CONSIDERATIONS

K-2100 Design Basis Analysis

(a) Is the component considered in design basis analysis?

(b) Is the component function considered important in the Safety Analysis Report?

(c) Are there any technical specification considerations for this component?

K-2200 Radioactive Material Release Limit

(a) Could the failure of this component be considered a breach in an engineered safety barrier?

(b) Could the failure of this component result in an uncontained release of radioactive material in excess of that allowed?

K-2300 Maintenance Reliability

(a) Is the component important to maintaining system reliability?

(b) What type of component failures have been experienced for this and similar style components?

(c) What does the maintenance history indicate about the reliability of this component?

(d) Does the component receive preventive maintenance, and is it effective for preventing identified failures?

(e) How are component failures detected?

K-2400 Effect of Component Failure on System Operational Readiness

(a) Is the component important to maintaining system availability?

(b) How does component failure affect system performance?

(c) Does component failure cause other system component failures?

(d) What is the system component level of defense in depth?

(e) Does the system or component perform other functions outside the scope of the PRA?

(f) Can system or component failure modes affect redundant trains or other similar components?

K-2500 Other Deterministic Considerations

(a) Should other component failure modes be considered in the PRA model?

(b) Is this component used to mitigate the consequences of an accident caused by external events?

(c) Is this component important for safe shutdown?

(d) Is this component required to maintain the safe shutdown condition?

(e) Should other component failure modes that may not be included in the PRA be considered (e.g., aging effects, structural supports, human performance failures)?

¹ This Appendix is included for informational purposes only. While it is related to [Subsection ISTE](#), it is not part of that Subsection.

Division 1, Nonmandatory Appendix L¹

Acceptance Guidelines

L-1000 PURPOSE

This Appendix provides guidance on the decision criteria for aggregate risk limits using CDF and LERF.

L-2000 ACCEPTANCE GUIDELINES

L-2100 Background and Introduction

The risk acceptance guidelines presented in this Appendix are structured as follows. Regions are established in the two planes generated by a measure of the baseline risk metric (CDF or LERF) along the x-axis, and the change in those metrics (Δ CDF or Δ LERF) along the y-axis (Figures L-2100-1 and L-2100-2). Acceptance guidelines are established for each region as discussed below. These guidelines are intended for comparison with a full PRA scope (including internal events, external events, full power, low power, and shutdown) assessment of the change in risk metric, and, when necessary, as discussed below, the baseline value of the risk metric (CDF or LERF). However, it is recognized that many PRAs are not full scope, and the use of less than full scope PRA information is acceptable as discussed in this Subsection.

There are two acceptance guidelines, one for CDF and one for LERF, both of which should be used.

L-2110 Acceptance Guidelines for CDF. The acceptance guidelines for CDF are as follows:

(a) If the change can be clearly shown to result in a decrease in CDF, then the change is satisfactory.

(b) When the calculated increase in CDF is very small, which is taken as being less than $1\text{E}-06$ per reactor year, the change should be considered regardless of whether there is a calculation of the total CDF (Region III). While there is no requirement to calculate the total CDF, should there be an indication that the CDF may be considerably higher than $1\text{E}-04$ per reactor year, then the focus should be on finding ways to decrease CDF. Such an indication would result, for example, if

(1) the contribution to CDF calculated from a limited scope analysis, such as the PRA, and, if appropriate, the PRA with external initiating events, significantly exceeds $1\text{E}-04$

(2) there has been an identification of a potential vulnerability from a margins type analysis or

(3) historical experience at the plant in question has indicated a potential safety concern

(c) When the calculated increase in CDF is in the range of $1\text{E}-06$ per reactor year to $1\text{E}-05$ per reactor year, changes should only be considered if it can be reasonably shown that the total CDF is less than $1\text{E}-04$ per reactor year (Region II).

(d) Applications that result in increases to CDF above $1\text{E}-05$ per reactor year (Region I) should not normally be considered.

L-2120 Guidelines for LERF. The guidelines for LERF are as follows:

(a) If the change can be clearly shown to result in a decrease in LERF, then the change is satisfactory.

(b) When the calculated increase in LERF is very small, which is taken as being less than $1\text{E}-07$ per reactor year, the change should be considered regardless of whether there is a calculation of the total LERF (Region III). While there is no requirement to calculate the total LERF, should there be an indication that the LERF may be considerably higher than $1\text{E}-05$ per reactor year, then the focus should be on finding ways to decrease rather than increase it. Such an indication would result, for example, if

(1) the contribution to LERF calculated from a limited scope analysis, such as that the IPE, and, if appropriate the IPEEE, significantly exceeds $1\text{E}-05$

(2) there has been an identification of a potential vulnerability from a margins type analysis or

(3) historical experience at the plant in question has indicated a potential safety concern

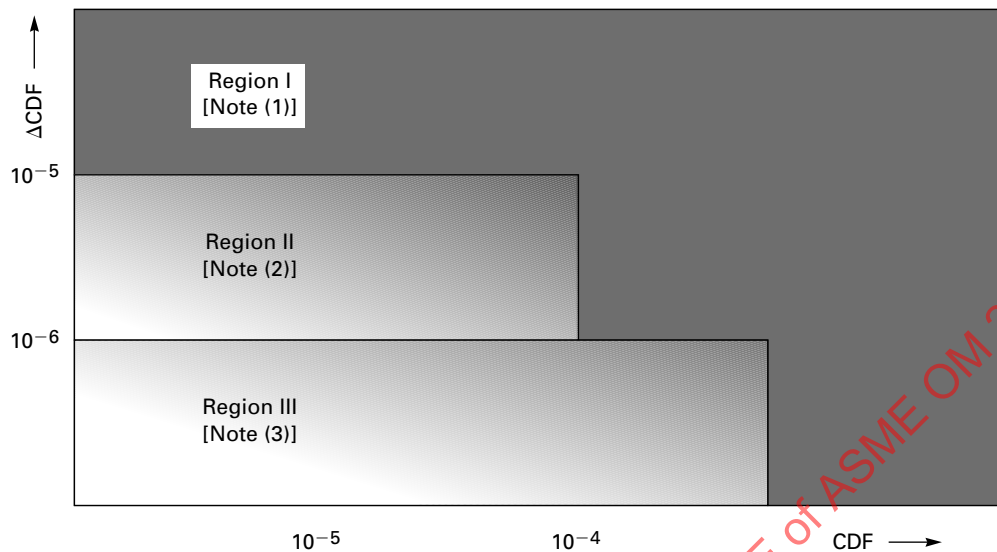
(c) When the calculated increase in LERF is in the range of $1\text{E}-07$ per reactor year to $1\text{E}-06$ per reactor year, changes should only be considered if it can be reasonably shown that the total LERF is less than $1\text{E}-05$ per reactor year (Region II).

(d) Changes that result in increases to LERF above $1\text{E}-06$ per reactor year (Region I) should not normally be considered.

L-2130 Additional Guidelines. These acceptance criteria are intended to provide assurance that proposed increases in CDF and LERF are small.

¹ This Appendix is included for informational purposes only. While it is related to Subsection ISTE, it is not part of that Subsection.

Figure L-2100-1
Acceptance Guidelines for CDF (Adapted From RG 1.174)



NOTES:

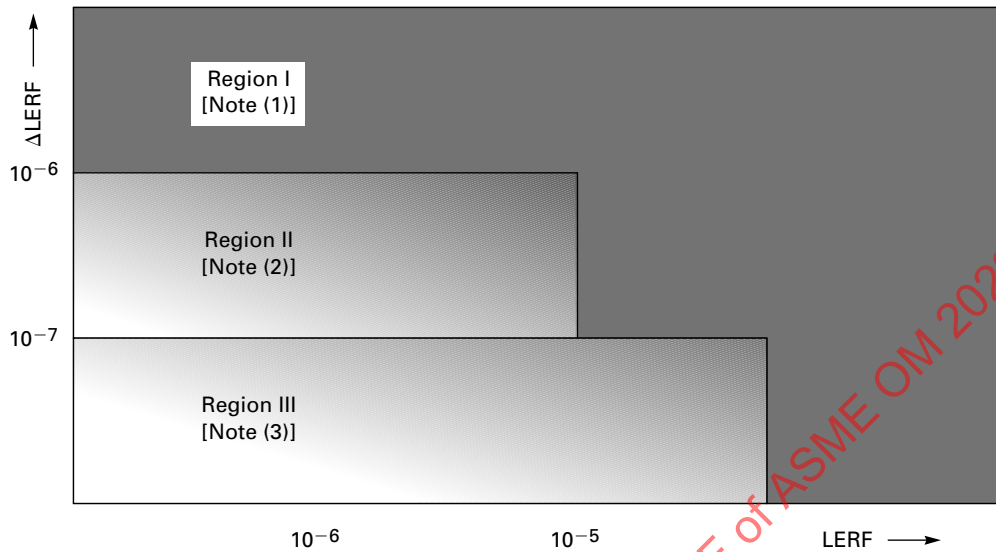
- (1) Region I: No changes allowed.
- (2) Region II:
 - (a) Small changes
 - (b) Track cumulative impacts
- (3) Region III:
 - (a) Very small changes
 - (b) More flexibility with respect to baseline CDF
 - (c) Track cumulative impacts

The analysis may be subject to a more detailed technical and management review depending upon the degree to which a change resides in a given region. In the context of the integrated decision making by the Plant Expert Panel, the boundaries between regions should not be interpreted as being definitive; the numerical

values associated with defining the regions in the figure are to be interpreted as being absolute.

As indicated by the shading on the figures, the change request should be subject to a technical and management review that becomes more intensive the closer the calculated results are to the region boundaries.

Figure L-2100-2
Acceptance Guidelines for LERF (Adapted From RG 1.174)



NOTES:

- (1) Region I: No changes allowed.
- (2) Region II:
 - (a) Small changes
 - (b) Track cumulative impacts
- (3) Region III:
 - (a) Very small changes
 - (b) More flexibility with respect to baseline LERF
 - (c) Track cumulative impacts

Division 1, Nonmandatory Appendix M

Design Guidance for Nuclear Power Plant Systems and Component Testing

M-1000 PURPOSE

This Appendix provides guidance for the design of systems and components in nuclear power plants to support preservice and inservice testing in accordance with the requirements of Divisions 1 through 3. The guidance is intended to support design activities for new plant construction, but can be considered for existing plant systems.

M-2000 BACKGROUND

Nuclear power plants are required to comply with the requirements for preservice and inservice testing set forth in the applicable edition of Division 1. In the past, Code applicability has caused Owners to obtain relief from some of these requirements or to perform costly modifications due to limitations in design or construction. With the inception of a new generation of nuclear power plants, it is prudent that these limitations be eliminated during the design phase.

In addition, Divisions 2 and 3 have been developed to provide guidance for performance testing of various plant systems and components. The design of new nuclear power plants provides an opportunity to enhance testability through incorporation of appropriate design features.

This Appendix is intended to support design organizations and is specifically intended to advise personnel responsible for the design of these plants regarding the provisions that should be considered when designing systems and components that will subsequently be subject to ASME OM requirements for preservice and inservice testing. Specific guidance is provided for selected parts of Divisions 1 through 3 for initial plant design.

M-3000 GUIDANCE

Lessons learned from nuclear power plant operating experience, industry degradation-monitoring programs for systems and components, and regulatory testing programs have revealed the need for an effective design and qualification process to allow the preservice and inservice testing programs to properly assess the operational readiness of plant components to perform their safety functions. To address this need, design per-

sonnel should establish an effective design and qualification process for pumps, valves, and dynamic restraints. ASME QME-1-2007¹ incorporates lessons learned from nuclear power plant operating experience and testing programs for the design and qualification of mechanical equipment to be used in nuclear power plants. ASME QME-1-2007 provides one approach for the functional design and qualification of pumps, valves, and dynamic restraints.

M-3100 General Test Capability Guidance

(a) Identify the components and systems that require testing based upon review of the Scope statements of Divisions 1 through 3 with consideration of approved plant-specific probabilistic risk assessments (PRAs), regulatory issues, or other design considerations.

(b) Determine the specific test requirements of Divisions 1 through 3 for each component and system identified per (a).

(c) Review the system design and the component specifications for testability for each test identified in (b) and provide design features to support the required testing. Not all requirements will apply to each component or system situation. Considerations include

- (1) the capability to perform full-flow testing of the system or pump
- (2) the capability to perform required testing during any plant operating mode, including normal operation
- (3) minimizing impact on plant safety and risk
- (4) minimizing Technical Specification Action State-ment entries
- (5) minimizing safety-system availability impact
- (6) minimizing temporary plant alterations to perform required testing
- (7) the capability to perform required leakage testing (e.g., valve, system, containment building, etc.)
- (8) the required test-instrumentation accuracy
- (9) instrumentation, component, and system accessibility for plant personnel, including dose and safety considerations

¹ As accepted in Revision 3 to NRC Regulatory Guide (RG) 1.100.

(10) the capability for test-data collection via inputs to the plant computer (e.g., pump pressure and flow data vs. time; valve position vs. time data)

(11) installing dedicated containment electrical penetrations for use by startup instrumentation, including provision for separate power and control penetrations

(12) minimizing the need for relief from the testing requirements of [Division 1](#)

(13) accommodating the application of software-based digital technology for pumps and valves

(14) assessing the potential adverse effects on pumps and valves from flow-induced vibration caused by hydrodynamic loads and acoustic resonance, by evaluating potential vibration levels as part of the design process, establishing vibration acceptance criteria, and monitoring vibration levels and performing walkdown assessments during preservice and inservice testing

(15) coordinating preservice testing and inspections, tests, analyses, and acceptance criteria (ITAAC) activities during the design process, where applicable

(16) the proper maintenance of inservice testing components and personnel training during the design process, and their relationship to preservice and inservice testing requirements

(d) Document the actions taken and the associated bases to address (a) through (c) in an appropriate manner that supports historical understanding of the bases for the design decisions.

M-3200 Subsection ISTF (Pumps)²

[Subsection ISTF](#) requires that pumps be tested periodically and performance data collected such that deviation from predetermined reference values can be determined and evaluated. Consider the following information to support [Subsection ISTF](#) testing and to minimize the plant impact from periodic testing. Some features are to be considered within the design of the connected piping system, while others are required information or features within the pump specification.

M-3210 Flow. Provide a broad flow range, including full flow, considering the following:

(a) Design the piping network to draw from an available source and return. Ensure that the entire testing flow path contains adequate vent valve locations to address potential gas accumulation. This is a system requirement.

(b) Design the piping path for use during normal power operation. This is a system requirement.

(c) Design throttling capability for the full range of required pump operation, from minimum flow to maximum required design-basis flow. Select valves with throttling resolution compatible with design test con-

ditions. Ensure that protection is provided to prevent pump runout. Evaluate the benefit of using normal system piping or dedicated test piping (or a combination) to ensure the flow testing range is accommodated.

(d) Design the systems for implementation of the comprehensive pump-testing provisions of [Division 1](#) without the need for regulatory relief.

(e) Design the test flow path to support the testing duration without pump heat raising fluid temperature above acceptable limits. If the test flow path will not have adequate cooling, describe this limitation in the pump purchase specification or consider an alternate recirculation-path heat exchanger with the capability for heat-removal cooling during power operation.

(f) Document expected test durations and performance parameters in the pump design specification.

(g) Design the flow path for the tested pump such that the operability of other pumps is not impacted during the test. Ensure that the discharge of the tested pumps is designed to avoid adverse interaction with other systems (e.g., shared miniflow, causing inoperability of an alternate train).

M-3220 Test Data Collection. Consider the following when data collection is required:

(a) Provide permanently installed instrumentation that will meet or exceed [Subsection ISTF](#) measurement-accuracy requirements to support data collection.

(1) Provide direct-flow measurement capability in the discharge piping of each individual pump, for each pump requiring [Subsection ISTF](#) testing.

(-a) Avoid reliance on a single wide-range instrument located in a common pump-discharge header. For example, provide a flow orifice with permanent differential pressure instrumentation.

(-b) Provide a suitable piping arrangement to assure accurate flow measurement.

(-c) Consider recommended location limitations as prescribed within a standards document such as ISO 5167:2003.

(2) Provide pump-discharge and suction pressure-measurement instrumentation in close proximity to the pump for measuring differential pressure for each pump requiring [Subsection ISTF](#) testing. Locate pressure taps in the piping configuration per the instrument manufacturer's recommendations or suitable industry standards such as those published by American National Standards Institute/Hydraulic Institute (ANSI/HI) or by ASME in the Performance Test Codes.

(3) Provide for vibration and speed measurement for each pump requiring [Subsection ISTF](#) testing. In addition, consider permanently installing accelerometers on shaft bearings to monitor vibration on deep draft pumps.

(4) Allow for in situ calibration, or accommodate easy removal to a calibration/instrument maintenance shop.

² [Subsection ISTF](#) applies to nuclear power plants with a construction permit or combined license issued on or after January 1, 2000; [Subsection ISTB](#) applies to nuclear power plants with a construction permit issued prior to January 1, 2000.

(5) Consider instrument fluctuations and readability to ensure test repeatability (i.e., readability for establishing reference values).

(b) Describe in the pump specification document explicit locations for the instruments and accuracy of this instrumentation when the instrumentation is to be supplied by the pump vendor.

M-3300 Subsection ISTC (Valves)

Subsection ISTC requires that valves be tested periodically and performance data collected to ensure that the valves are performing within specified acceptance limits.

Based on the required function(s), provide for the following types of testing in the plant design.

M-3310 Leak-Rate Testing of Subsection ISTC, Category A Valves

(a) Design system configurations to support leak-rate testing as follows:

(1) Provide upstream and downstream isolation capability such that the test volume can be pressurized with the appropriate medium to the required test pressure. For example, for containment isolation valves (CIVs) that may come in direct contact with the primary containment atmosphere following an accident, provide the capability to perform leak-rate testing using air or other pneumatic media at a pressure equal to the maximum postaccident containment pressure.

(2) Provide test connections upstream and downstream of the Category A valves for pressurization and venting to ensure that the required pressure differential is achieved and that the Category A valves can be tested in the accident mitigation direction.

(3) Provide capability to test valves during normal plant operation where practical.

(4) Locate valves to be accessible during normal plant operation.

(5) Provide a test configuration that will not affect the operability or availability of redundant systems during the test duration.

(6) Provide the capability to isolate individual valves to support testing and facilitate diagnosis or repair for system configurations with parallel isolation valves.

(7) Provide capability to perform leak-rate testing using the service medium for the system at a pressure equal to the maximum pressure to which the valve will be exposed during the specific function for which it is designed.

(b) Design test-data collection capability as follows:

(1) Provide suitable provisions to connect temporary pressure-measurement instrumentation that will meet Subsection ISTC measurement accuracy requirements for the test connections described in (a)(2).

(2) Provide suitable arrangement for measurement of leakage flow, pressure feed rate, or pressure decay versus time. Provide means to contain leakage inventory

or have suitable drain capability for leakage-flow measurement.

(3) Provide permanently installed instrumentation that will meet or exceed Subsection ISTC measurement accuracy requirements for locations where local access may not be possible during required testing.

M-3320 Exercise Testing of Subsection ISTC, Category A and Category B Valves. Design system configurations to support exercise testing as follows:

(a) Provide system configuration such that the system is not adversely impacted by stroking the valve (i.e., it does not cause loss of system keep-fill function).

(b) Provide system configuration such that the operability or availability of redundant valves or systems are not impacted during the stroke test.

M-3330 Exercise Testing of Subsection ISTC, Category C Valves

(a) Design system configurations to support exercise testing as follows:

(1) Provide test connections upstream of the check valve to allow reverse-flow testing.

(2) Provide test connections as required to facilitate makeup or motive flow for forward- and reverse-flow testing.

(3) Provide testable check valves where required forward- or reverse-flow testing cannot be performed.

(b) Design test-data collection capability to support exercise testing as follows:

(1) Provide instrumentation to verify that forward-flow criteria are met for check valves.

(2) Provide instrumentation upstream of the check valve to facilitate reverse-flow testing.

(3) Refer to M-3310(b) for further instrumentation guidance.

M-3340 Exercise Testing of Subsection ISTC, Category D Valves

(a) Design system configurations to support ISTC requirements as follows:

(1) Provide unobstructed local visual access to non-reclosing pressure relief devices.

(2) Provide unobstructed local access to the charge on pyrotechnic-actuated (squib) valves.

(b) Include provisions in squib valve designs for the capability to perform, with sufficient access, inservice testing and inspection activities to assess the integrity of internal parts and the presence of fluid or foreign material that might adversely impact the performance or integrity of the squib valve and its actuator.

M-3350 Position-Indication Verification Testing of Subsection ISTC Valves

(a) Provide unobstructed local visual access for valve-position confirmation for valves with remote position indication.

(b) For valves that cannot be observed directly, such as solenoid valves, specify instrumentation that can be used to confirm actual valve position.

M-3360 Valve Specifications or Plant Design.

Consider the following provisions in the valve specification or plant design as appropriate:

(a) Design test-data collection capability to support diagnostic testing of motor-operated valves (MOVs), air-operated valves (AOVs), and hydraulic-operated valves (HOVs) as follows:

(1) Provide inputs to the plant computer to allow collection of sufficient diagnostic data of performance parameters for power-operated valves to ensure proper setup and performance evaluation per Subsection ISTC requirements.

(2) Refer to [M-3310\(b\)](#) for further instrumentation guidance.

(b) Diagnostic Testing of MOVs

(1) Specify valve assemblies (valve and operator) with built-in, or with the ability to accept, monitoring and diagnostic equipment (e.g., stem strain gages, smart-valve technology). Include quick-disconnect capability for diagnostic equipment to the valve motor and internal torque and limit switches.

(2) Specify that the valve design provides for monitoring potential rotor degradation, where applicable (such as in magnesium rotors).

(3) Ensure the system design allows for the periodic verification of MOV design-basis capability during preservice and inservice testing. Design the system to allow MOV testing at design conditions (e.g., full-flow and design temperature and pressure). This includes considerations set forth in [Division 1, Mandatory Appendix III](#) that mandate that a program be established to ensure that MOVs continue to be capable of performing their design-basis safety functions.

(4) Provide ready access at motor-control centers to allow diagnostic testing of MOVs.

(5) Specify MOV orientation and location during the design process to ensure consideration of the potential impact on access for IST activities and maintenance.

(c) Diagnostic Testing of AOVs

(1) Specify valve assemblies (valve and operator) with built-in, or with the ability to accept, monitoring and diagnostic equipment (e.g., smart-valve technology).

(2) Consider guidance provided for AOVs by [Division 3, Part 19](#).

(3) Ensure the system design allows for the periodic verification of AOV design-basis capability during preservice and inservice testing. Design the system to allow AOV

testing at design conditions (e.g., full-flow and design temperature and pressure).

(4) Ensure the system and valve design applies the lessons learned from MOV-operating experience and performance testing to facilitate testing of AOVs.

(d) Diagnostic Testing of HOVs

(1) Specify valve assemblies (valve and operator) with built-in, or with the ability to accept, monitoring and diagnostic equipment (e.g., smart-valve technology).

(2) Consider guidance provided for HOVs by [Division 3, Part 19](#).

(3) Ensure the system design allows for the periodic verification of HOV design-basis capability during preservice and inservice testing. Design the system to allow HOV testing at design conditions (e.g., full-flow and design temperature and pressure).

(4) Ensure the system and valve design applies the lessons learned from MOV-operating experience and performance testing to facilitate testing of HOVs.

(e) Check Valve Testing

(1) Consider specification of external disk movement devices.

(2) Consider specification of built-in, or the ability to accept, monitoring and diagnostic equipment.

(f) Safety/Relief Valve Testing

(1) Provide local access for removal and reinstallation of relief valves to accommodate remote testing.

(2) Provide isolation for relief valves to minimize system draindown and refill impact due to valve removal, while maintaining compliance with applicable design codes.

(g) *Manual Valve Testing.* Specify hand-wheel capability with appropriate extension shafts for local unobstructed access to valves during normal operation. Provide access for the operation, periodic testing, and inspection of manual valves to ensure their capability to perform any applicable safety functions at design-basis system and environmental conditions.

M-3400 Subsection ISTD (Snubbers)

(a) Select the location along the pipe to minimize interference with local structures, components, and adjacent piping.

(b) Provide local access to snubbers for visual inspection and for removal for testing and reinstallation.

(c) Provide rigging support locations for snubber removal and replacement.

(d) Consider the impact on system availability if a snubber is temporarily removed for testing.

(e) Minimize the impact of removing a single snubber on alternate system or component trains or divisions.

(f) Consider specifying snubbers with built-in, or with the ability to accept, diagnostic equipment (e.g., load pin and displacement transducers) where appropriate based upon size, ease of removal, location access, and operational impact of removal.

M-3500 Other Considerations

The following are considerations for the design organization to accommodate testing of certain non-Code components and monitoring systems.

M-3510 Division 2, Part 21 (Inservice Performance Testing of Heat Exchangers), and Division 3, Part 11 (Vibration Testing and Assessment of Heat Exchangers)

(a) Evaluate the need for future testing per the requirements of Division 2, Part 21, and Division 3, Part 11.

(b) Design installed instrumentation accordingly with consideration of associated accuracy. Pay particular attention to temperature measurement on primary and secondary sides, considering instrumentation location and accuracy due to the sensitivity of these data in the performance evaluation.

(c) Provide suitable access for internal visual inspection. Consider this information in preparation of the component's specification.

(d) Provide suitable access and clearance area to permit disassembly (i.e., bundle removal).

M-3520 Division 2, Part 12 (Loose Part Monitoring). Consider guidance provided by Division 2, Part 12 for the design of loose part monitoring systems.

M-3530 Division 2, Part 24 (Reactor Coolant Pumps and Recirculation Pumps). Consider guidance provided by Division 2, Part 24 for the design of pump-monitoring systems.

(22) **M-3540 Division 3, Part 14 (Condition Monitoring of Rotating Equipment).** Consider specification of installed vibration-monitoring capability as recommended by Division 3, Part 14.

M-3550 Division 2, Part 16 (Standby Diesel Generator Systems)

(a) Review Division 2, Part 16 for diesel testing recommendations and consider appropriate features in the design specification.

(b) Consider specification of diesel and generator components and subcomponents with built-in, or with the ability to accept, diagnostic and monitoring equipment.

(1) Consider adding provisions for monitoring and diagnostics of the mechanical equipment (e.g., taps for pressure gages, or recorders or transmitters).

(2) Consider adding provisions for monitoring and diagnostics of the electrical equipment (e.g., voltages, high-speed recorders for signal capture).

(c) Consider provisions of permanently installed instrumentation that will meet or exceed measurement accuracy requirements to support data collection described in Part 16.

(d) For subcomponents within the scope of ISTC and ISTF, refer to M-3200 and M-3300, respectively, for additional guidance.

M-3560 Division 2, Part 3 (Vibration Testing of Piping Systems), and Division 3, Part 7 (Thermal Expansion Testing)

(a) Consider specification of installed capability for monitoring vibration and thermal expansion as recommended by Division 2, Part 3, and Division 3, Part 7.

(b) Consider inclusion of piping pressure taps for installation of dynamic pressure transducers during startup testing.

(c) Consider including load cell installation on snubbers.

(d) Consider accommodations for installation of test instrumentation (e.g., accelerometers or displacement indicators) at locations throughout the plant, and associated instrumentation brackets. Consider the use of wireless technology to minimize cable routing.

(e) Consider installing dedicated containment electrical penetrations for use by startup instrumentation, including provision for separate power and control penetrations.

(f) Nuclear power plant operating experience reveals the importance of maintaining vibration of plant components within acceptable limits. When considering the above guidance for vibration testing, ensure that the plant design facilitates monitoring the dynamic effects of steady-state flow-induced vibration and anticipated operational transient conditions on critical system components.

M-3570 Division 3, Part 19 (Pneumatically and Hydraulically Operated Valves). Consider guidance provided by Division 3, Part 19 in addition to M-3360(b)(1) and M-3360(c)(1).

M-3600 Division 2, Part 28 (System Testing Capability)

Division 2, Part 28 provides a robust roadmap for system testing. A detailed review of that Part reveals the following considerations for the plant design organization:

(a) Capture and thoroughly document the design basis for plant systems to ensure that system performance requirements are understood by the plant owner.

(b) Provide the capability for online multipoint pump-performance testing, for systems with variable flow requirements.

(c) Provide pressure measurement capability at locations in the tested system to the extent of data location necessary to support discharge-path flow resistance.

(d) Establish the data measurement requirements, considering instrumentation location and accuracy due to the sensitivity of these data in the evaluation of

performance test results. Provide suitable instrumentation hardware commensurate with the testing frequency (i.e., installed hardware to support frequent testing, temporary hardware for infrequent testing).

(e) Provide system alignment capability that maximizes simultaneous or integrated testing.

(f) Provide system alignment capability that will allow single-train testing without impact on other trains.

(g) Provide flow measurement for minimum recirculation flow path.

M-4000 REFERENCES

ASME QME-1-2007, Qualification of Active Mechanical Equipment Used in Nuclear Power Plants

Publisher: The American Society of Mechanical Engineers (ASME), Two Park Avenue, New York, NY 10016-5990 (www.asme.org)

ISO 5167:2003, Measurement of fluid flow by means of pressure differential devices inserted in circular cross-section conduits running full

Publisher: International Organization for Standardization (ISO), Central Secretariat, Chemin de Blandonnet 8, Case Postale 401, 1214 Vernier, Geneva, Switzerland (www.iso.org)

ASMENORMDOC.COM : Click to view the full PDF of ASME OM 2022

DIVISION 2 OM STANDARDS

Part 2 Performance Testing of Closed Cooling Water Systems in Light-Water Reactor Power Plants

Superseded by Part 28.

ASMENORMDOC.COM : Click to view the full PDF of ASME OM-2022

Part 3

Vibration Testing of Piping Systems

1 SCOPE

This Part establishes vibration testing requirements for certain piping systems in water-cooled reactor nuclear power plants. This Part is applicable to preservice and initial startup testing, and plant post modification testing (e.g., power uprate and steam generator replacement). This Part may be used to assess vibration levels of applicable piping system during plant operation. 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 B31.1: Power Piping.

ASME BPVC: 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 BPVC, 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.

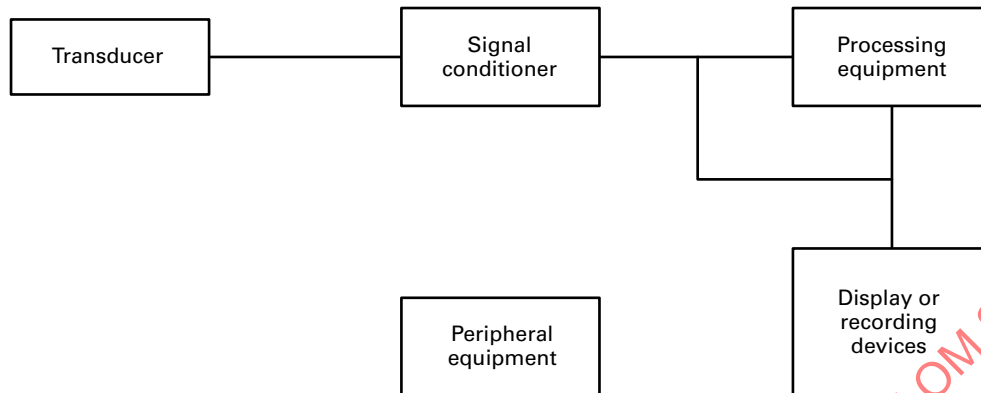
record drawing set: the set of drawings that defines the system's layout and support configuration at the time the system is placed in service for testing.

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.

Figure 1
Typical Components of a Vibration Monitoring System (VMS)



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

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 section 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 composed 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 vari-

able and readily convertible to appropriate physical units. A typical VMS is shown in Figure 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)

Table 1
System Tolerances

System Design Parameters	Allowable Tolerance Range	Units	
		U.S. 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/h
Overall heat transfer coefficient [Note (4)]	-10%	Btu/hr-ft ² -°F	Cal/h-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, ft² (cm²); 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.

(j) instrumentation to be used (including instrument specifications)

(k) data handling and storage

(l) system restoration

(m) system tolerances on test conditions (see Table 1)

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 section 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 section 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 section 2)

(b) piping systems for which the methods of VMG 2 and VMG 3 are not applicable based on limitations given in sections 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 B31.1 piping systems that are not expected to exhibit significant vibrational response based on past experience with similar systems or system operating conditions

(22) 3.1.2 Transient Vibration

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 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 are designed and analyzed for known anticipated dynamic loading conditions and for the applied loading (i.e., fluid or mechanical), which 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 if provided sufficient justification is given. More stringent criteria shall be invoked if these assumptions are deemed inappropriate for the system under review.

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

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

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

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

(e) Strain-controlled fatigue curves of the ASME BPVC, 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 section 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.

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

Alternatively, $2i$ may be substituted for $C_2 K_2$ for applications where the piping design is based on the use of stress intensification factors (i).

where

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

i = stress intensification factor, as defined in ASME BPVC, Section III, or ASME B31.1

- K_2 = local stress index as defined in ASME BPVC, 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} = fatigue stress endurance limit equal to S_A at 10^{11} cycles from ASME BPVC, Section III, Figure I-9.1 or Figure I-9.2, as applicable. The user shall consider the influence of temperature on the modulus of elasticity.
- Z = section modulus of the pipe

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 BPVC, Section III, Figure I-9.1 or Figure I-9.2.

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 BPVC.

(b) For ASME Classes 2 and 3 and ASME B31.1 piping, the stresses shall be evaluated in accordance with the requirements of para. 3.2.1.2. 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 section 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 section 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 section 5, the methods and devices of section 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 section 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 section 4, the methods and devices of section 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 section 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 handheld or temporarily mounted transducer that is suitable for making 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

(section 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 Figures 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 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 para. 3.2.1.2.

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.

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

$$\delta_{allow} = (S_{el} \times \delta_n) / (C_2 K_2 \times \sigma_n)$$

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 (σ_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}) of the piping material and the peak stress indices ($C_2 K_2$)

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} , 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 Figure 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

Figure 2
Deflection Measurement at the Intersection of Pipe and Elbow

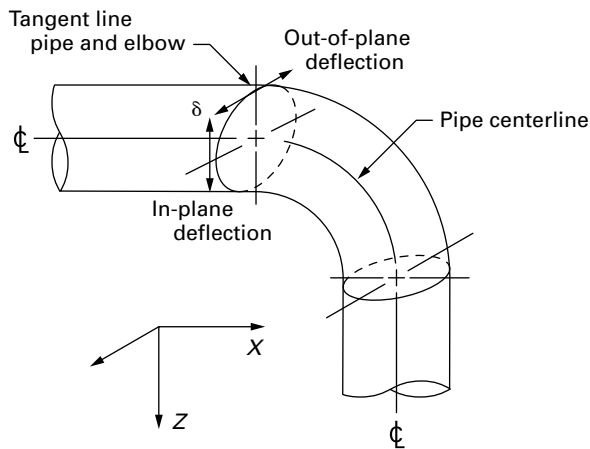


Figure 5
Cantilever Span/Elbow Span In-Plane Deflection Measurement

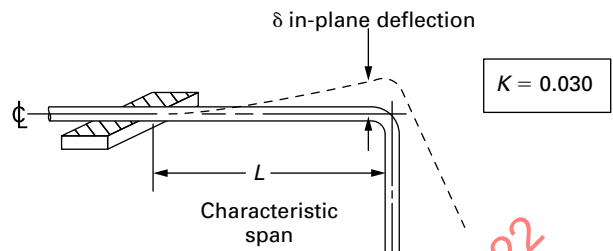


Figure 6
Cantilever Span/Elbow Guided Span In-Plane Deflection Measurement

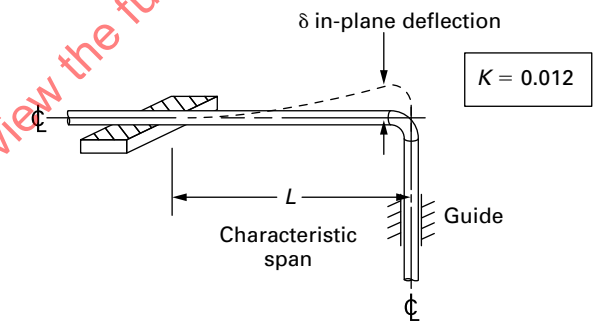


Figure 3
Single Span Deflection Measurement

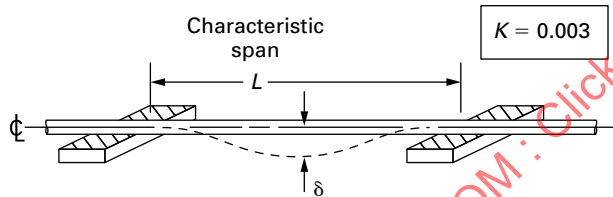


Figure 4
Cantilever Span Deflection Measurement

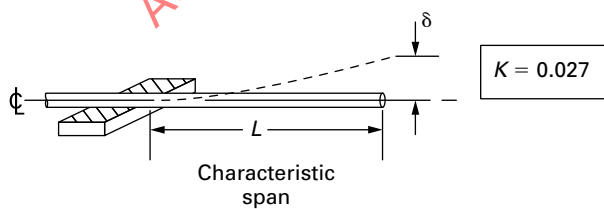
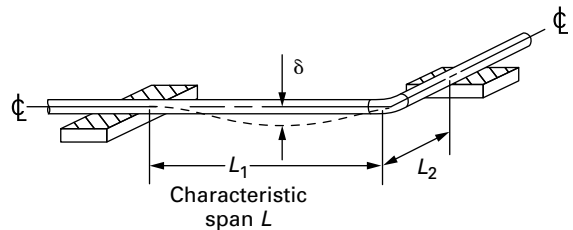


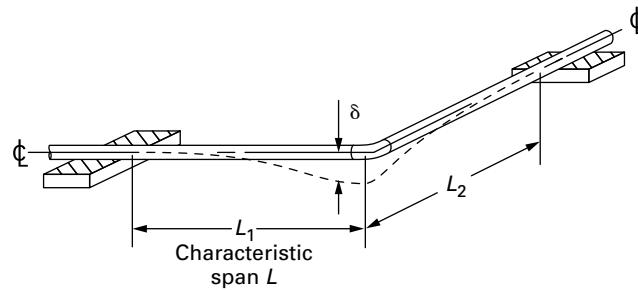
Figure 7
Span/Elbow Span Out-of-Plane Deflection Measurement, Span Ratio < 0.5



GENERAL NOTES:

- (a) L_2/L_1 less than 0.5.
- (b) See Figure 9 for K .

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



GENERAL NOTES:

- (a) L_2/L_1 between 0.5 and 1.0.
 (b) See Figure 9 for K .

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 (Figure 4)
 (2) cantilever span, elbow, span
 (-a) deflection in plane of elbow, end span free (Figure 5)
 (-b) deflection in plane of elbow, guided end span (Figure 6)
 (b) Restraint at both ends
 (1) single span
 (-a) single span (Figure 3)
 (-b) single span with elbow restraint [special case of para. (b)(1)(-a) or limit case of para. (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 (Figure 7 with configuration coefficient K from Figure 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 (Figure 8 with configuration coefficient K from Figure 9)

5.1.2 Velocity Method

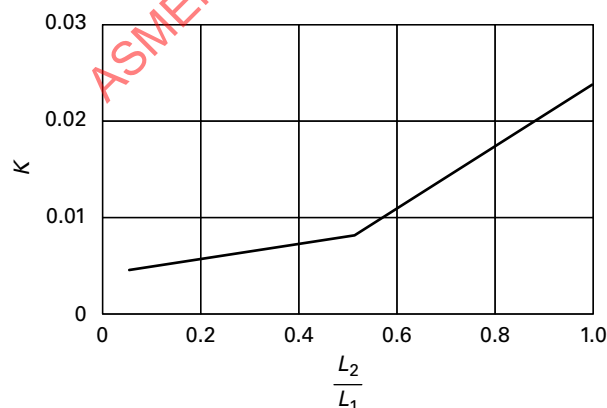
5.1.2.1 General Requirements. The method requires consecutive measurements of velocity at various points on the piping system to locate the point that is exhibiting the maximum vibratory velocity. Once this point is located, a final measurement of the maximum velocity, $V_{\max}$, at that point is made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

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

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

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



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

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

where

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

$\beta = 3.64 \times 10^{-3}$ to obtain V_{allow} in in./sec when S_{el} is in units of psi

= 13.4 to obtain V_{allow} in mm/s when S_{el} is in units of MPa

S_{el} , C_2 , and K_2 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 Figure 10)

C_3 = a correction factor accounting for pipe contents and insulation

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

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 (kg/m)

W_{INS} = the weight of the insulation per unit length, lb/ft (kg/m)

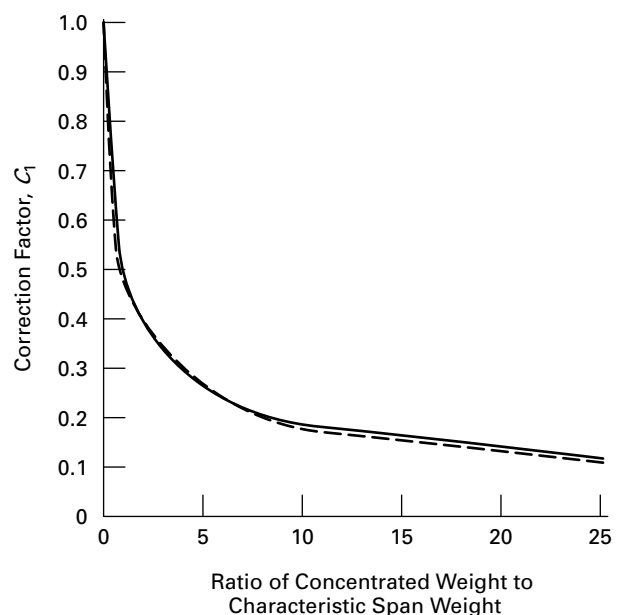
= 1.0 for pipe without insulation and either empty or containing steam

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.

Figure 10
Correction Factor C_1



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 multispans 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.

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 section 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 section 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 section 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 (22)

The rigorous verification method is required when the portion of the system is evaluated in VMG 1 or when the methods of sections 4 and 5 are not applicable or are overly conservative. 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 Test and Analysis Correlation Technique (22)

6.1.1 General Requirements. The test and analysis correlation technique requires that vibrational displacements and frequencies of the system be identified from the test data.

The test and analysis correlation technique also requires that analysis of the system be performed yielding analytically determined displacements and stresses corresponding to the predominant measured vibration frequencies. The analysis and test vibratory responses of the piping system shall be correlated to determine the state of stress in the piping due to the measured displacements.

6.1.2 Test Requirements. The piping system shall be instrumented sufficiently to enable correlation of the test and analysis results. The instrumentation may be capable of measuring acceleration, displacement, or velocity according to the guidelines of section 7. Instruments shall be located close to where vibrational displacements are anticipated to be significant relative to other points in 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 displacements and frequencies at the measurement locations. Data processing methods are discussed in Nonmandatory Appendix B.

6.1.4 Test and Analysis Correlation. The measured vibrational frequencies and displacements of the piping system shall be correlated to analytically obtained vibrational frequencies and displacements. Analysis methods that may be used for correlation to measured vibrations are discussed in Nonmandatory Appendix C. As a minimum, the analytically obtained displacements shall conservatively represent the measured displacements; the relative magnitudes of the analytical and measured displacements need not be identical at every location. In addition, the predominant frequencies of the test and analysis shall be in reasonable agreement.

6.1.5 Evaluation of the Measured Responses. The measured vibrational 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. Methods for obtaining the vibrational stress in the piping using the measured piping displacements and the displacements and stresses from the analysis of the system are 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 included in 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

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)

(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 included in 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.

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

(22)

A-1 PURPOSE

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

A-2 VISUAL METHODS (VMG 3)

The visual inspection method allows the use of senses, such as sight and touch, to determine acceptability. The use of senses for estimating vibration amplitudes and determining acceptability should be based on previous vibration measurement and evaluation experience.

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 vibration [<30 mils (<0.76 mm)] at relatively high frequencies (>20 Hz) would be difficult to quantify with a spring hanger scale.

The use of visual methods is intended for those vibrations that can be qualified with certainty based on judgment and experience. If doubt exists as to acceptability after the visual inspection methods are employed, then the methods of section A-3 of this Appendix should be employed.

A-3 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-3.1 Transducers

A-3.1.1 Accelerometers. The piezoelectric accelerometer is a commonly used transducer for measuring power plant piping vibration. An accelerometer measures the pipe acceleration at the location and in the direction that the accelerometer is installed. The measured acceleration can be integrated to provide velocity and displacement

through the use of electronics or software. Piezoelectric accelerometers have large amplitude and frequency ranges. They are intrinsically low noise and specific designs are suitable for use in high temperature and radiation environments. In general, the piezoelectric accelerometer is rugged, relatively easy to install in a variety of locations, and reliable for long periods of time.

Accelerometers are low mass and may be attached directly to the pipe or appurtenance by a strap, bolt, magnet, or glue. Conversely, displacement transducers need two attachments, one end to the pipe and one end to a fixed support. Piezoelectric accelerometers with integrated electronics are suitable for low-temperature measurements and do not require a separate (remote) charge converter. For higher temperatures, a remote charge converter is typically required. The accelerometer and charge converter temperature specifications should be reviewed to determine applicability for the expected temperature conditions.

The following accelerometer characteristics are particularly important:

(a) *Sensitivity.* The accelerometer sensitivity provides the output charge or voltage for a given input acceleration. The accelerometer sensitivity should be selected to assure that the accelerometer will produce sufficient output for the expected acceleration relative to the expected noise floor.

(b) *Amplitude Range.* The amplitude range of an accelerometer is the range from the minimum acceleration level to the maximum acceleration level that an accelerometer can accurately measure. The expected acceleration should be well within this range. When a remote charge converter is used, the amplitude range of the charge converter may be the limiting factor.

(c) *Temperature Sensitivity.* The accelerometer will experience nearly the same temperature variation as the structure to which it is attached. Variation from room temperature may cause changes in the accelerometer sensitivity that if not accounted for will cause inaccuracy in the measurement.

(d) *Useful Frequency Range.* The useful frequency range primarily depends on the accelerometer type and the mounting technique. The acceptable frequency range specified by the manufacturer is typically for a stud-mounted installation. Other mounting methods will likely reduce the frequency range of the

accelerometer installation. The accelerometer manufacturer can assist in determining the effect of the installation technique on frequency range. Piezoelectric accelerometers can measure a wide frequency range, typically from 1 Hz to 2 Hz to several kilohertz. When a remote charge converter is used, the frequency range of the charge converter, especially at the low end, may be the limiting factor.

(e) *Temperature Range.* The specified temperature range of the accelerometer should be greater than any temperature the accelerometer is expected to experience in use.

Integration of acceleration signals to produce velocity or displacement should be done with caution due to potential errors in the low frequency range (<5 Hz). It may be possible to establish an accurate frequency range by inserting known acceleration values over a broad frequency range into the integration method and comparing the output to the calculated results. Even after establishing an acceptable frequency range, checks should be made between the low-frequency accelerations and the integrated velocity and displacements by comparing the spectra for both and calculating the expected displacement result from the acceleration spectrum. Integration considerations are discussed further in Nonmandatory Appendix B.

A-3.1.2 Displacement Transducers. The displacement transducers most applicable to piping vibration measurements are the linear variable differential transformer (LVDT), the lanyard potentiometer, and, to a lesser extent, the eddy current probe (i.e., proximity probe). All of these devices sense absolute displacement relative to a fixed reference and, therefore, have frequency responses down to 0 Hz (DC). The displacement transducer needs to be attached to a fixed support with the sensing end attached to the vibrating object. In operating power plants, it may be difficult to find a fixed support near where the measurement is required, so support fixtures may need to be installed to support the transducer. Displacement transducers are limited in their high-frequency response relative to accelerometers, but have a higher response at lower frequencies. Since displacement is measured directly, the integration concerns associated with accelerometer measurements at low frequencies are not applicable to displacement transducers.

A-3.1.3 Strain Gages. The use of strain gages at selected points in the piping system provides data that is more directly related to stress than acceleration, velocity, or displacement. 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.

Strain gages normally used on piping systems are either the bondable or the weldable types. Bondable strain gages can be used in lower-temperature applications, but due to the high temperatures associated with much of the piping in nuclear power plants, weldable strain gages are commonly used. Weldable strain gages are also simpler to install than bondable strain gages. Strain gage sensitivity changes with temperature; therefore, a sensitivity correction may be necessary to ensure accurate values at temperatures other than room temperature. Temperature compensation may also be required to account for differences in thermal expansion properties between the strain gage and pipe materials.

Using more than one strain gage at a location on a pipe configured properly in a Wheatstone bridge can provide outputs proportional to desired measurement parameters (e.g., bending, torsional or axial strain, dynamic pressure), increased sensitivity, and compensation for temperature variation. For vibration measurements, static strain offsets can be removed by either AC coupling (i.e., removal of the DC component of the signal using a high-pass filter) or zeroing the static component of the Wheatstone bridge output.

Vibration strain is typically very low in amplitude; therefore, signal conditioning with high gain capability should be used. In addition to high gain, the excitation voltage can be maximized to provide additional sensitivity. Each strain gage type has a maximum allowable excitation voltage that should not be exceeded.

A-3.1.4 Pressure Transducers. The vibration transducers discussed in paras. A-3.1.1 through A-3.1.3 measure the pipe response under dynamic load; whereas, dynamic pressure transducers can provide amplitude and frequency characteristics of fluid pressure fluctuations causing the pipe loading. This type of pressure transducer differs from permanently installed pressure instruments used to measure system operating pressure.

A permanently installed pressure instrument is typically a cavity type transducer with an internal pressure diaphragm designed to measure static pressure and is usually located in an instrument rack at the end of a long tubing run. A dynamic pressure transducer has an external flush-mounted diaphragm that ideally is installed through the pipe wall with the diaphragm flush with the inside wall surface.

A flush-mounted installation can be achieved by drilling through the pipe wall, which is often considered too risky by the plant operator. Alternatively, an insertion probe can be used to install a pressure transducer in an existing vent or drain line to achieve a flush-mounted installation. Acceptable measurements can also be obtained from a dynamic pressure transducer installed at the end of a relatively short vent or drain line (i.e., stub); however, the measurement results need to account for the acoustic response of the stub. Placing dynamic pressure transducers at the end of long tubing runs introduces significant

pressure signals related to the acoustic characteristics of the tubing and should be avoided.

Piezoelectric pressure transducers, which have characteristics similar to piezoelectric accelerometers, are most commonly used for dynamic pressure measurements. Piezoresistive pressure transducers, which have characteristics similar to strain gages, can also be used in some applications. Alternatively, properly oriented strain gages may be used to obtain pipe strain readings proportional to dynamic pressure.

A-3.2 Electrical Cables

Vibration transducers generate low-level voltages in the microvolt to millivolt range; therefore, the electrical cables that are used with vibration sensors require an electrical shield to prevent the induction of electrical noise into the cable. Typical electrical cables used with vibration instrumentation are coaxial cables and shielded, twisted-pair cables. The shield in both situations should only be grounded on one end of the cable, with the other end floating from ground.

Cables should be sized based on the electrical current requirements of the transducers. Generally, the cables used with vibration instrumentation are in the 16 AWG to 22 AWG (1.291 mm to 0.644 mm) range. The cables should have temperature characteristics adequate for the expected environment. The cables should also meet the plant's fire, chemical, and radiation requirements.

Containment electrical penetrations have a history of being sources of noise, primarily due to shielding issues and nearby high-voltage signals. The cables in the penetration should be shielded and ideally not mixed with high-voltage equipment cables. The shield can be either a continuation of the shield from the transducer or the start of a new shield. In any case, each shield should only be grounded on one end.

A-3.3 Signal Conditioner

The signal conditioner provides one or more of the following functions:

(a) *Transducer Power.* Many transducers need some type of power either for internal electronics, such as charge converters for piezoelectric accelerometers, or for the sensing elements themselves, such as strain gages. The transducer's power requirements should be met by the signal conditioner.

(b) *Signal Amplification.* Many transducers provide low voltage output proportional to the physical input. Amplification at the signal conditioner can increase the signal so that the amplitude is well above the noise induced by the electronics. While maximizing the signal is important, too much amplification could saturate the signal. Vibration that is due to flow is generally quasi-random amplitude, so it is possible to have peaks that are many times higher than the rms value. Saturation occurs when one or more of these peaks are above the specified full-scale voltage of the

signal conditioner. To ensure saturation does not occur, the user should observe the vibration time history for each channel to be recorded for a sufficient period of time at the settings established for the test, and adjust the settings as needed.

(c) *Signal Zeroing.* Many transducers, such as strain gages and displacement transducers, have an electrical zero offset due to imbalance in the transducer's electrical circuit or due to the environmental effect on the transducer. In most vibration measurements this zero is irrelevant, so it can be eliminated by zeroing the electrical output at the rest position. With the voltage output near zero, the amplification can be increased to provide better signal range and an increase in the signal-to-noise ratio.

(d) *Filtering (e.g., Low-Pass, High-Pass, Band-Pass, Band-Stop).* Filtering serves several purposes. In general, filtering provides the ability to observe data in a particular frequency range while reducing the noise created by data outside the frequency range of interest. For data that is digitized, an anti-aliasing filter, which is a type of low-pass filter, should be applied prior to digitization. An anti-aliasing filter removes frequency content (typically frequencies $>$ sampling frequency/2.56) that could be aliased during digitization and manifested falsely as lower frequency content within the frequency range of interest. A high-pass filter can eliminate low frequencies, including DC offsets, providing the possibility for increased amplification (and increased signal-to-noise ratio). A band-pass filter can allow the user to view a signal in a very narrow bandwidth. A band-stop, or notch, filter can be used to eliminate specific, unwanted frequencies (e.g., electrical noise at 60 Hz and harmonics).

(e) *Integration.* Integration of an acceleration signal can be performed to obtain velocity and displacement. As stated in para. A-3.1.1, the integration process has inherent noise issues at very low frequencies ($< \sim 5$ Hz) that should be accounted for in interpretation of the measurements.

In general, the signal conditioner amplitude and frequency range should be compatible with the expected amplitude and frequency range of the vibration of interest and the selected transducer. The operational power demand of the transducer should be met by the signal conditioner. The output voltage of the signal conditioner should not exceed the input limits of the electronics that follow (e.g., recorder, analog-to-digital converter).

A-3.4 Vibration Monitoring System

The VMS can vary from a handheld instrument that can collect one or two channels of data and provide a variety of analyses (e.g., rms, peak, peak-to-peak vibration values, frequency spectra, time history) to full-featured multi-channel data recording systems. The VMS is generally a digital, computer-based system, which means the analog signal from the vibration sensor is at some

point digitized and stored in a digital format for either real-time analysis or offline analysis.

A typical multichannel system consists of the transducers, cables, and signal conditioning discussed in paras. A-3.1 through A-3.3 followed by an analog-to-digital converter that converts the analog signals to a digital format fed into a computer for real-time display and data storage. Typically, the software provided with the system will provide all the functions necessary to set up a test, trigger automatically or manually, perform real-time or offline vibration analysis, display several channels of data in the time and frequency domains, and record the data to disk.

The sample rate per channel for converting the analog signals to digital signals should be at least 3 times the highest frequency of interest. Sample rates 5 times or more than the highest frequency of interest are commonly used. The data from all channels should be simultaneously

sampled in order to preserve the phase relationship between the channels. The typical analog-to-digital converter has a 16 bit to 24 bit conversion range; that is, the full scale input resolution is the maximum-to-minimum, full-scale engineering value divided by 2^{16} or 2^{24} . Data should be recorded for a sufficient period of time to ensure that the maximum vibration amplitudes are captured.

Digital data acquisition systems should have an analog, anti-aliasing filter for each channel that is applied prior to the analog-to-digital conversion in order to prevent aliased (i.e., nonreal) data from appearing in the frequency range of interest.

The VMS from transducer to data storage should be configured to ensure that the system maximizes the signal, minimizes noise, has no saturation, and covers the frequency bandwidth of interest.

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Part 3, Nonmandatory Appendix B

Data Processing Methods

(22)

B-1 PURPOSE

For piping systems evaluated using VMG 1 or VMG 2 methodologies, vibration data is typically obtained using a vibration monitoring system (VMS). Additional processing of the vibration data is typically required to obtain values that can be compared to established acceptance criteria and for correlation with vibration analyses. This Appendix provides guidance for performing effective vibration data processing.

B-2 TIME DOMAIN DATA PROCESSING CONSIDERATIONS

Typically, unprocessed (raw) vibration data is collected in the form of acceleration or displacement versus time. The raw time domain data is then processed into more useful forms in order to enable further analysis of piping system vibration stresses. Considerations for collecting and processing of time domain data are discussed in paras. B-2.1 through B-2.5.

B-2.1 Time Span Selection

The recording time span should be selected based on the vibration phenomena that are being evaluated. When recording steady-state vibration data, a 2-min to 3-min time span is usually sufficient for capturing representative vibration responses. When recording transient vibration data, the entire transient event should be recorded, if possible. Very long recordings (e.g., hours or days) may present data storage and processing issues due to large data file sizes. Therefore, developing specialized tools for data management may be necessary and should be considered in the planning stages. For example, incorporating data acquisition triggers based on exceeding threshold values where feasible can be used to manage file sizes and simplify data processing.

B-2.2 Initial Adjustments to Time Domain Data

In some cases, it may be desirable to select only a portion of the time domain data in a particular data set for further processing. For example, steady-state vibration data may contain spurious peaks due to electrical noise, isolated transient events, or other sources that are not representative of steady-state responses. Figure B-1 provides a graphical depiction of the selected

and rejected portions of a time domain data set for a typical steady-state response that includes spurious content.

Time domain data that is not AC coupled (i.e., the DC component of the signal is not removed using a high-pass filter) is typically not centered around zero amplitude, which is referred to as DC offset. On a frequency domain (i.e., spectrum) plot, the DC offset is represented by a frequency bin at 0 Hz. DC offset can be removed by subtracting the overall mean value for each channel from that channel's data points. This methodology is defined in eq. (B-1), and an example of the DC removal process is shown graphically in Figure B-2.

$$\bar{y}_n = y_n - \bar{y}_N \quad (\text{B-1})$$

where

$\bar{y}_N$ = mean amplitude of the entire data set, where N is the total number of points in the data set

y_n = raw time history data point (prior to DC offset removal), where n is a point between the start and end of the data set

$\bar{y}_n$ = alternating time history data point with DC offset removed, where n is a point between the start and end of the data set

B-2.3 Filtering

Filtering of time domain data is often desired to remove frequencies that are not reflective of the pipe stresses caused by piping vibration. Low-pass filtering can be used to remove frequencies above the frequency range of interest. High-pass filtering is used to remove low-frequency components that are artifacts of digital integration. Notch, or band-stop, filtering can be used to remove specific frequencies, e.g., 60 Hz electrical noise.

Digital filters have a rise time, which may result in oscillation (ringing) in the time domain at the point of filter application for certain initial conditions. If present, this effect can be removed by truncating the processed time history data in the affected region(s).

An example of the effects of a band-pass filter, which is a combination of a high-pass filter and a low-pass filter, shown in the frequency domain is provided in Figure B-3. An example of the effects of a band-stop filter used to remove electrical noise, also shown in the

Figure B-1
Example of Time Span Selection to Exclude Spurious Data

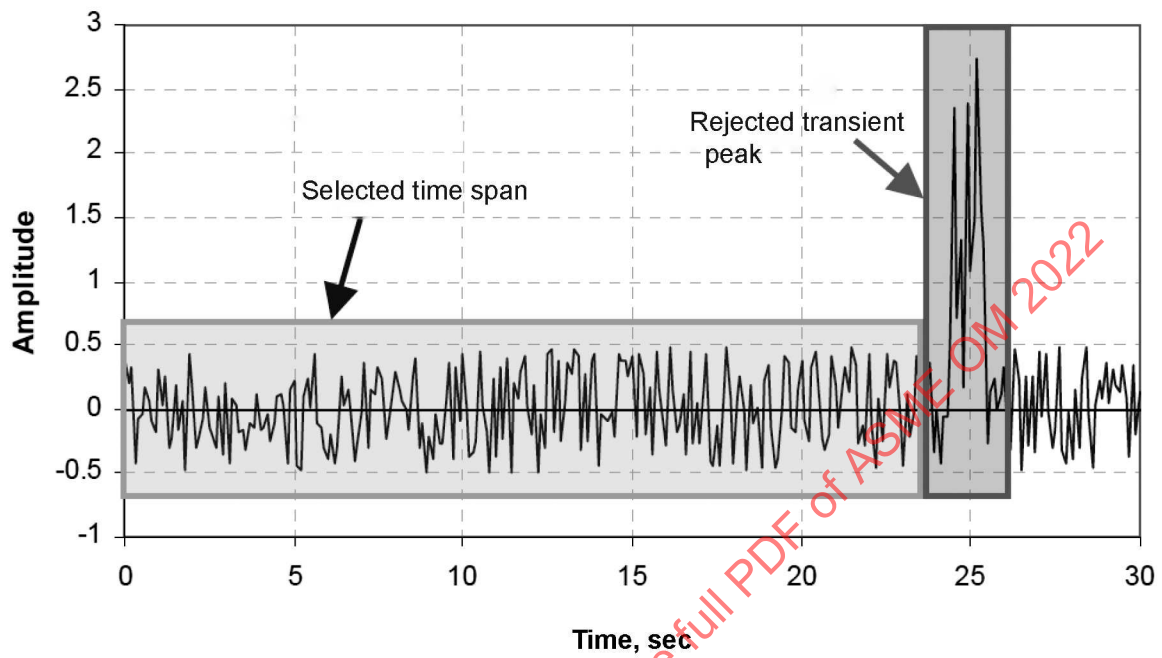


Figure B-2
Example of DC Offset Removal

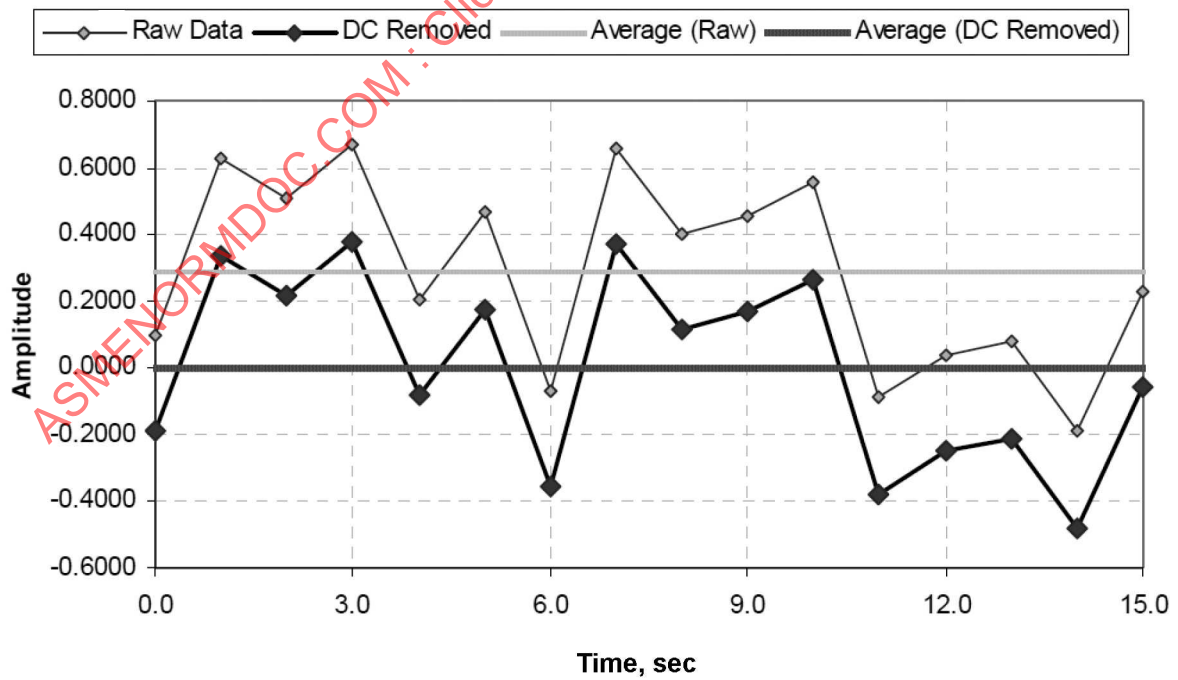
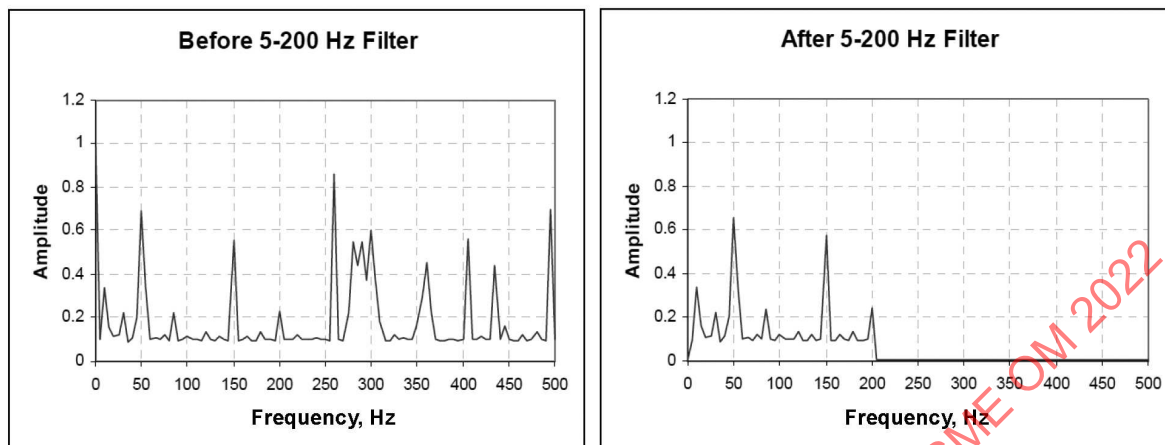


Figure B-3
Example of Band-Pass Filtering Between 5 Hz and 200 Hz



frequency domain, is provided in Figure B-4. It is the responsibility of the analyst to verify that actual pipe vibration frequencies of interest are not removed by the application of filters.

B-2.4 Waveform Integration

Acceleration data needs to be integrated to velocity or double integrated to displacement for comparison to velocity or displacement limits. The acceleration data can be digitally integrated using various methods, such as the rectangle, trapezoid, or Simpson's rule.

Acceleration amplitudes are typically low with respect to the signal noise floor at low frequencies. Since the signal noise is integrated along with the actual accelerations, the amplitudes of the integrated data at low frequencies can

be significantly distorted. This distortion can often be observed as data amplitudes that increase exponentially as frequency approaches zero. As discussed in para. B-1.3, a high-pass filter can be used to minimize the effects of integration at low frequencies.

B-2.5 Determination of Overall Values

Overall values are extracted from the processed time domain data for comparison to established acceptance limits. Overall vibration amplitudes are typically expressed as rms, zero to peak, or peak to peak.

The rms value for a series of data points is computed as shown in eq. (B-2).

Figure B-4
Example of Band-Stop Filtering for a 60 Hz Electrical Noise Peak

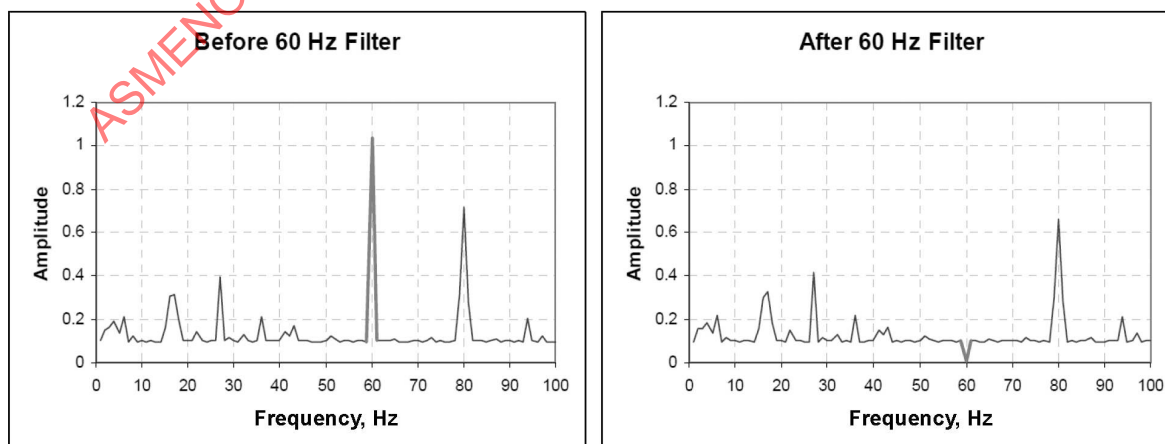
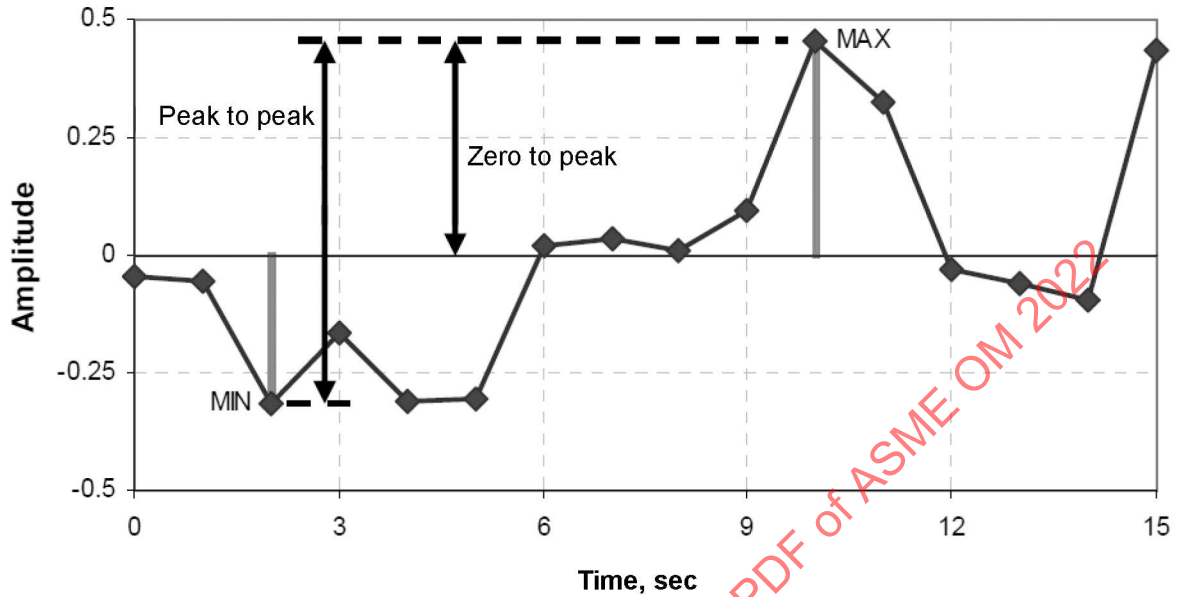


Figure B-5
Example of Zero-to-Peak and Peak-to-Peak Values



$$\text{rms} = \sqrt{\frac{1}{N} \sum_{i=1}^N f(x_i)^2}$$

(B-2)

$$\text{zero-peak} = \max[\text{eq. (B-3), eq. (B-4)}]$$

(B-5)

where

$f(x_i)$ = individual time history data point

N = total number of points in the data set

Evaluation of the stress level in a piping system due to vibration should be based on maximum and minimum peak values, not rms values. Applying a factor 1.414, corresponding to a pure sinusoid, to convert from rms to peak amplitude generally significantly underestimates actual peak values for piping steady-state vibration and should not be used.

Zero-to-peak and peak-to-peak values are derived from the maximum and minimum values of the data set. For long data sets, peak-to-peak values may be determined from maximum and minimum values over a specified time range. These values may be obtained from standard statistical formulas, such as those shown in eqs. (B-3) through (B-6). An example of the determination of zero-to-peak and peak-to-peak values where the mean value is zero is shown graphically in Figure B-5.

$$\text{zero-peak}(+) = \text{MAX} - \text{MEAN} \quad (\text{B-3})$$

$$\text{zero-peak}(-) = \text{MEAN} - \text{MIN} \quad (\text{B-4})$$

$$\text{peak-peak} = \text{MAX} - \text{MIN}$$

(B-6)

where

MAX = statistical maximum of the entire data set or specified time range

MIN = statistical minimum of the entire data set or specified time range

MEAN = statistical mean of the entire data set or specified time range

B-3 FREQUENCY DOMAIN DATA PROCESSING CONSIDERATIONS

Converting time domain data to the frequency domain (i.e., amplitude vs. frequency) is useful for verification of data validity, identification of predominant vibration frequencies, and identification of potential vibration sources. Frequency domain data processing considerations are discussed in paras. B-3.1 through B-3.3.

B-3.1 Fast Fourier Transform

Time domain data is converted to the frequency domain by means of a Fourier Transform; in many cases, a variation of a Fast Fourier Transform (FFT) algorithm is used. The general methodology behind an FFT algorithm is given in eq. (B-7).

$$F(x) = \text{FFT}[f(t)] \quad (\text{B-7})$$

where

$f(t)$ = a continuous function, sampled at some discrete interval Δt

$F(x)$ = the frequency spectrum resulting from the FFT of $f(t)$

FFT[] = the FFT algorithm used to perform the frequency transfer

Commercially available software packages include FFT routines for conversion from time domain to frequency domain.

B-3.1.1 Frequency Resolution. For a given set of steady-state data, the time history function $f(x)$ can be partitioned into one or more data blocks, and the FFT is performed on each block. The frequency resolution, Δf , of the FFT-generated spectra is inversely proportional to the length of the data block.

B-3.1.2 Averaging and Overlap. In most cases, the length of the recorded data is greater than the period of a data block. For example, at a frequency resolution of 0.25 Hz (4-sec block length), 20 sec of recorded data would yield five uniform, independent data blocks. In order to reduce the effect of one-time outlying peaks on the FFT results, the spectra resulting from each block should be linearly averaged, as demonstrated in eq. (B-8).

$$F(x)_{\text{avg}} = \frac{\sum_{i=1}^N F(x_i)}{N_b} \quad (\text{B-8})$$

where

$F(x)_{\text{avg}}$ = the linearly averaged frequency spectra for the entire data set

$F(x_i)$ = FFT result for an individual block i

N_b = number of data blocks in the data set

In order to increase the number of spectral averages, the data blocks can be overlapped. Using the parameters in the example above, with blocks overlapping by 50%, would result in nine data blocks of 4-sec length for the original 20-sec data set. This approach is depicted graphically in Figure B-6.

B-3.2 Interpretation of Spectral Frequencies

The predominant frequencies occurring in the vibration spectral plot provide an indication of the vibration source. Broadband frequency content with higher peaks at low

frequencies that can be correlated to piping system natural frequencies is indicative of flow turbulence. Broadband frequency content with higher amplitudes at higher frequencies can be indicative of cavitation.

Some sources of vibration can create peaks at multiples of a fundamental frequency. Rotating machinery, such as pumps, will produce spectral peaks at multiples of the rotational frequency. For example, a centrifugal pump with a five-vane impeller can produce peaks at 1 times the rotational frequency, which can correspond to rotational imbalance; 2 times the rotational frequency, which can correspond to shaft misalignment; and 5 times the rotational frequency, which corresponds to the vane pass frequency. Additional harmonics of the pump rotational speed can also be present. Acoustic frequencies corresponding to standing waves in branch piping (i.e., organ pipe frequencies) occur at odd number multiples (1, 3, 5, etc.) of a fundamental frequency. Other sources of vibration can also be discerned from analyzing the frequency content.

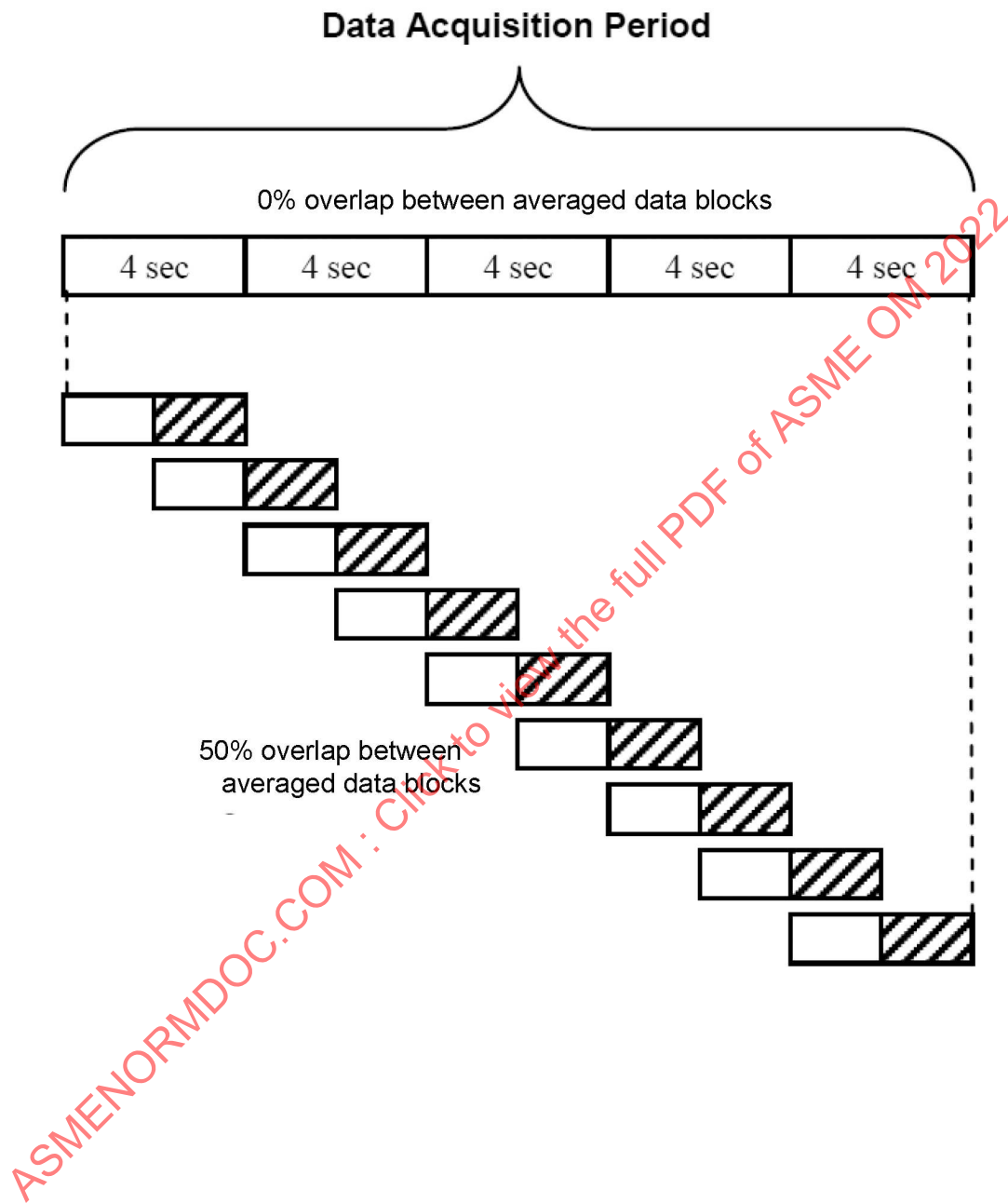
Acoustic and vortex shedding frequencies tend to have relatively sharp peaks. Structural resonances, which occur when excitation frequencies coincide with structural natural frequencies, tend to have broader peaks. This width of the peak is proportional to the amount of damping in the system, and structural damping tends to be higher than acoustic damping.

B-3.3 Interpretation of Spectral Amplitudes

Frequency spectral plots are representative of vibration responses over a period of time, typically the length of the data set. The amplitudes of specific frequency components are, therefore, representative of the average amplitude of each frequency component over the time period. In addition, the amplitudes of the specific frequency components are dependent on the frequency resolution of the spectral plot. Therefore, maximum peak vibration amplitudes cannot be accurately determined from spectral plots and should always be determined from the time domain data.

The amplitudes of the frequency components in spectral plots are most useful for comparison purposes, such as comparing amplitudes at different frequencies in the same data set or comparing amplitudes of the same frequency in different data sets. These comparisons can be used to help determine vibration sources and for evaluating vibrations for different operating conditions.

Figure B-6
Example of 50% Spectral Block Overlapping



Part 3, Nonmandatory Appendix C

Vibration Analysis Methods

(22)

C-1 PURPOSE

This Appendix presents analysis methods that can be used to determine piping system vibratory responses for correlation with and evaluation of measured responses. These methods are recommended to be used in conjunction with Part 3, para. 6.1. These methods can also be used for establishing vibration acceptance criteria prior to obtaining vibration measurements.

C-2 RESPONSE SPECTRUM ANALYSIS METHOD

The response spectrum analysis method produces vibratory responses at the natural frequencies of the piping system within a specified frequency range. For this method, simplified response spectra are applied at rigid support locations. The frequency range of the applied response spectra should correspond to the range of the predominant measured frequencies. The shape of the response spectra may be flat, stepped, sloped, or otherwise, as appropriate, for correlation to the measured piping responses.

The analytically determined piping displacements should be scaled so that they are greater than or equal to the measured displacements. Depending on the complexity of the piping system, different scaling factors may be appropriate for different portions of the system. The analytically determined pipe stresses should be scaled using the displacement scaling factors and evaluated according to the requirements of Part 3, para. 6.1.5.

C-3 TIME HISTORY ANALYSIS METHOD

The time history analysis method produces vibratory responses at the frequencies of the applied forcing functions. For this method, force time histories are applied to the piping legs in the axial direction. The frequency range of the applied force time histories should correspond to the range of the predominant measured frequencies. Because the force time histories are applied in a manner representative of flow-induced vibration loading, this method produces responses that are representative of steady-state vibration responses.

Piping leg force time histories can be generated by performing an acoustic analysis of the piping system or by other means that produce analytical responses

that can be correlated to the measured responses. If an acoustic analysis is performed, pressure pulsations with frequency content corresponding to the range of predominant measured frequencies are applied to an acoustic model of the piping. The resulting piping leg force time histories will reflect the frequency content of the applied pressure pulsations with amplification at the acoustic natural frequencies of the piping system. When the force time histories are applied to the piping structural model, the piping responses will occur at the frequencies of the applied forcing functions with amplification at the structural natural frequencies of the piping system. If other methods are used to generate piping leg force time histories, the frequency content of the force time histories should be reflective of the predominant measured frequencies.

The analytically determined piping displacements should be scaled so that they are greater than or equal to the measured displacements. Depending on the complexity of the piping system, different scaling factors may be appropriate for different portions of the system. The analytically determined pipe stresses should be scaled using the displacement scaling factors and evaluated according to the requirements of Part 3, para. 6.1.5.

C-4 VIBRATION ACCEPTANCE CRITERIA ANALYSIS

The response spectrum and time history analysis methods may also be used to develop vibration acceptance criteria prior to obtaining vibration measurements. For these analyses, the frequency range of the applied response spectra or force time histories should correspond to the anticipated range of the predominant measured frequencies. The analytically determined piping stresses should be scaled so that the maximum stress is equal to the allowable stress according to Part 3, para. 3.2.1.2. Depending on the complexity of the piping system, different scaling factors may be appropriate for different portions of the system. The analytically determined displacements at the specified measurement locations should be scaled using the stress scaling factors to obtain allowable displacement limits. The frequency content of the measured vibrations should be reviewed to confirm that the frequency range used in the analysis is appropriate.

C-5 ACOUSTIC VIBRATION ANALYSIS

In some instances, a significant component of the piping vibratory response may occur at distinct frequencies due to pressure pulsations associated with a known acoustic source. For example, centrifugal pumps produce pressure pulsations at the impeller vane passing frequency, positive displacement pumps produce pressure pulsations at frequencies related to the pump speed and the number of pistons or plungers, and vortex shedding at branch openings can produce pressure pulsations at frequencies related to flow velocity and branch opening diameter. Significant amplification can occur when the pressure pulsation frequency coincides with an acoustic natural frequency in the system.

In these instances, an acoustic analysis of the system can be used as an aid for evaluating system vibration responses and performing corrective actions. The acoustic analysis can be used to determine acoustic natural frequencies and acoustic responses due to the acoustic excitation source. The acoustic analysis results should be benchmarked against dynamic pressure measurements obtained during applicable operating conditions. Once benchmarked, the acoustic model can be used to investigate the impacts of changes to operating parameters or system configuration on acoustic responses. The acoustic analysis results from the benchmarked acoustic model can also be used as input to time history analyses performed to evaluate vibration responses.

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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

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

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.

$C_2 K_2$ = stress indices as defined in the ASME Code; $C_2 K_2 \leq 4$ 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

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

= 0.74 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} = 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.

$$C_1 = 0.15$$

$$C_2 K_2 = 4$$

$$C_3 = 1.414$$

$$C_4 = 0.74$$

$$C_5 = 1.0$$

$$S_{\text{el}} = 7,000 \text{ psi (48 MPa)}$$

$$V_{\text{allow}} = \text{screening vibration velocity value}$$

$$= \frac{(0.15)(0.74)(0.00364)(7,000)}{(1.414)(1.0)(4.0)}$$

$$= 0.5 \text{ in./sec (12.7 mm/s)}$$

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 $C_2 K_2$ 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

or 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 step-down 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 9 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.

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.

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-1.3 Response of Supports

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.

On systems that experience significant vibration, the design of the support systems should be reviewed to determine if they provide adequate restraint. The frequency of the supports and auxiliary steel may need to be increased above that of expected and/or anticipated piping vibration frequencies to avoid resonance with the piping vibration. Vibration of the supports and auxiliary steel could also potentially result in fatigue failure of the supports. In this case, the support and auxiliary steel should accommodate the applicable design basis and vibrational loads and be designed to have a natural frequency above expected pipe vibration frequencies.

Vibration movements of piping can also potentially result in rubbing and wear of the pipe wall at some types of supports. A box support with a gap between

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

the piping and support steel can potentially cause wearing of the pipe wall if the pipe vibrates and rubs against the support steel.

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, section 5 may be demonstrated to be within acceptable limits when more detailed techniques are used. The methods of Part 3, section 5 were developed to be efficient methods of qualifying the

majority of piping; however, conservative assumptions were made to simplify the criteria. Therefore, by 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, section 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.

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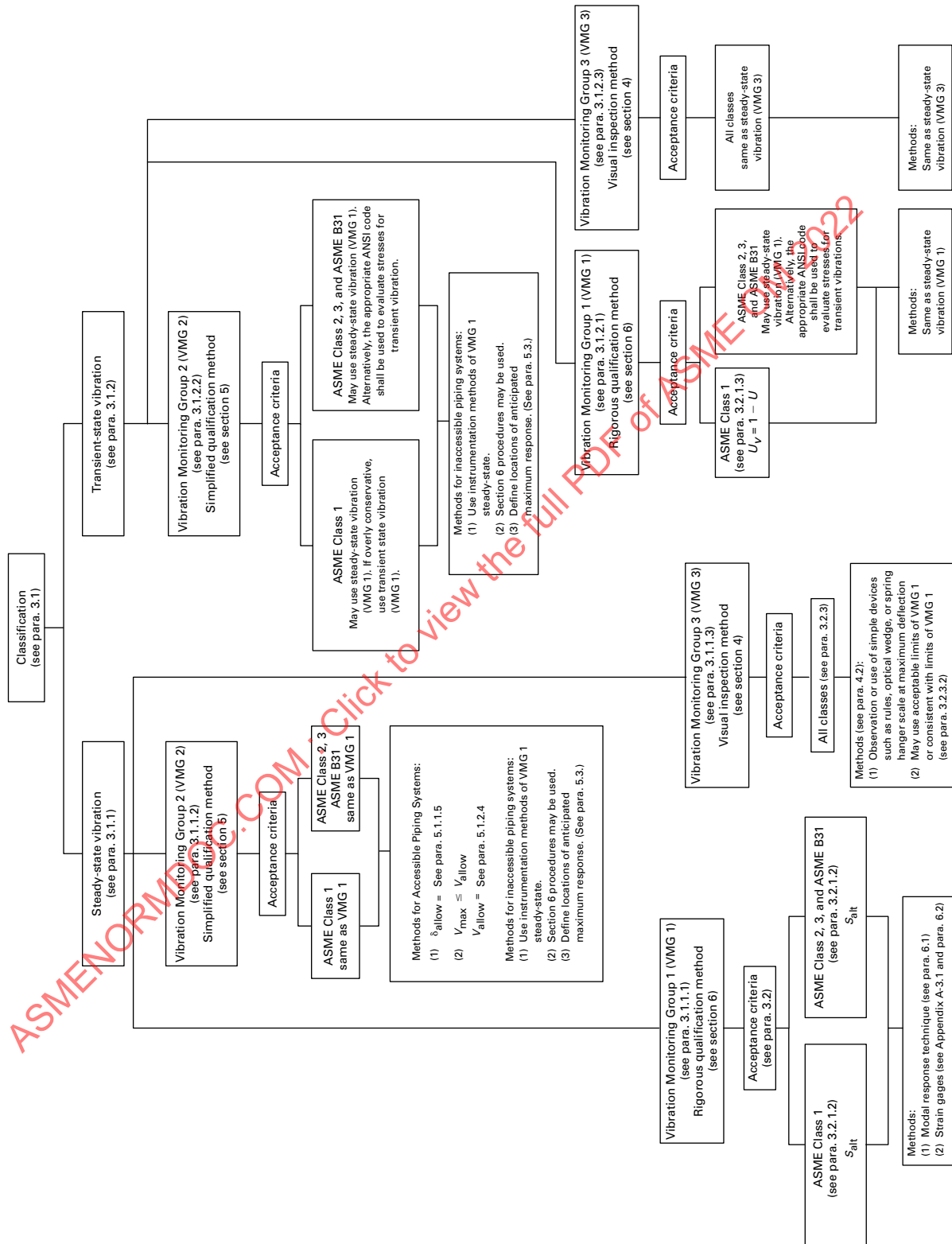
Part 3, Nonmandatory Appendix F

Flowchart — Outline of Vibration Qualification of Piping Systems

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

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Figure F-1
Flowchart — 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 walk-down. 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 vibra-

tion (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, section 3. These stress amplitudes are based on the alternating stress intensity at 10^6 cycles. Note that the assumptions stated in the ASME BPVC 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 BPVC, Section III, NB-3222.4.

H-3 IMPLEMENTATION

A sample steady-state vibration monitoring procedure is shown in Figure 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.

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 section 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 section 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 section 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 3, section 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.,

Figure H-1
Monitoring and Qualification of Piping Steady-State Vibration

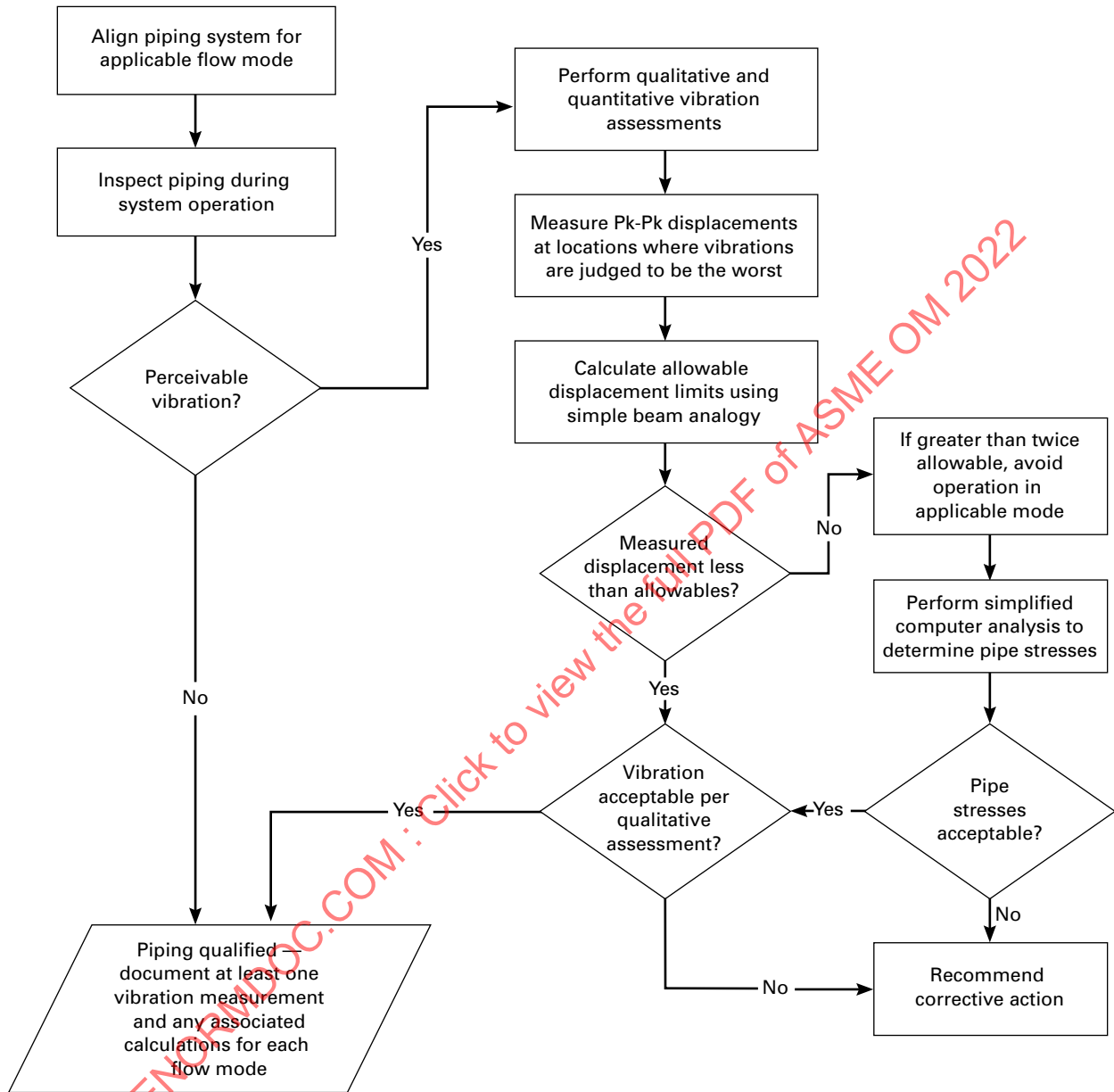


Table H-1
Recommended Actions for Piping Vibration Problem Resolution

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

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 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 (section 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 and, 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, section 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, section 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, section 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, section 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

$$\alpha_A = \frac{S_{el} \times z}{C_2 K_2 \times W_T L_E} \times \epsilon$$

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 (m³)
- 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 ($C_2 K_2$ 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 $C_2 K_2$ are applicable.

A $\frac{3}{4}$ in. Schedule 80 cantilevered branch line is accelerated by a header pipe at a peak acceleration of $1.0g$ (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 Figure 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 $C_2 K_2 = 4.2$.

$$\alpha_A = \frac{1,667z}{W_T L_E}$$

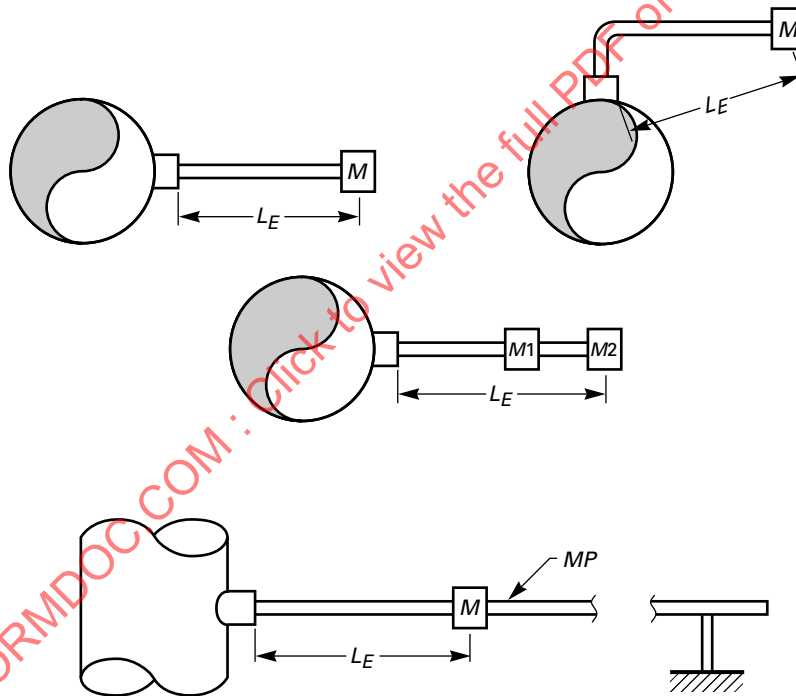
$$\alpha_A = \frac{1,667z}{W_T L_E} = \frac{(1,667 \times 0.0853)}{(16.6 \times 6)} = 1.43g > 1.0g$$

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 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.

Figure 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

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 requirements 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

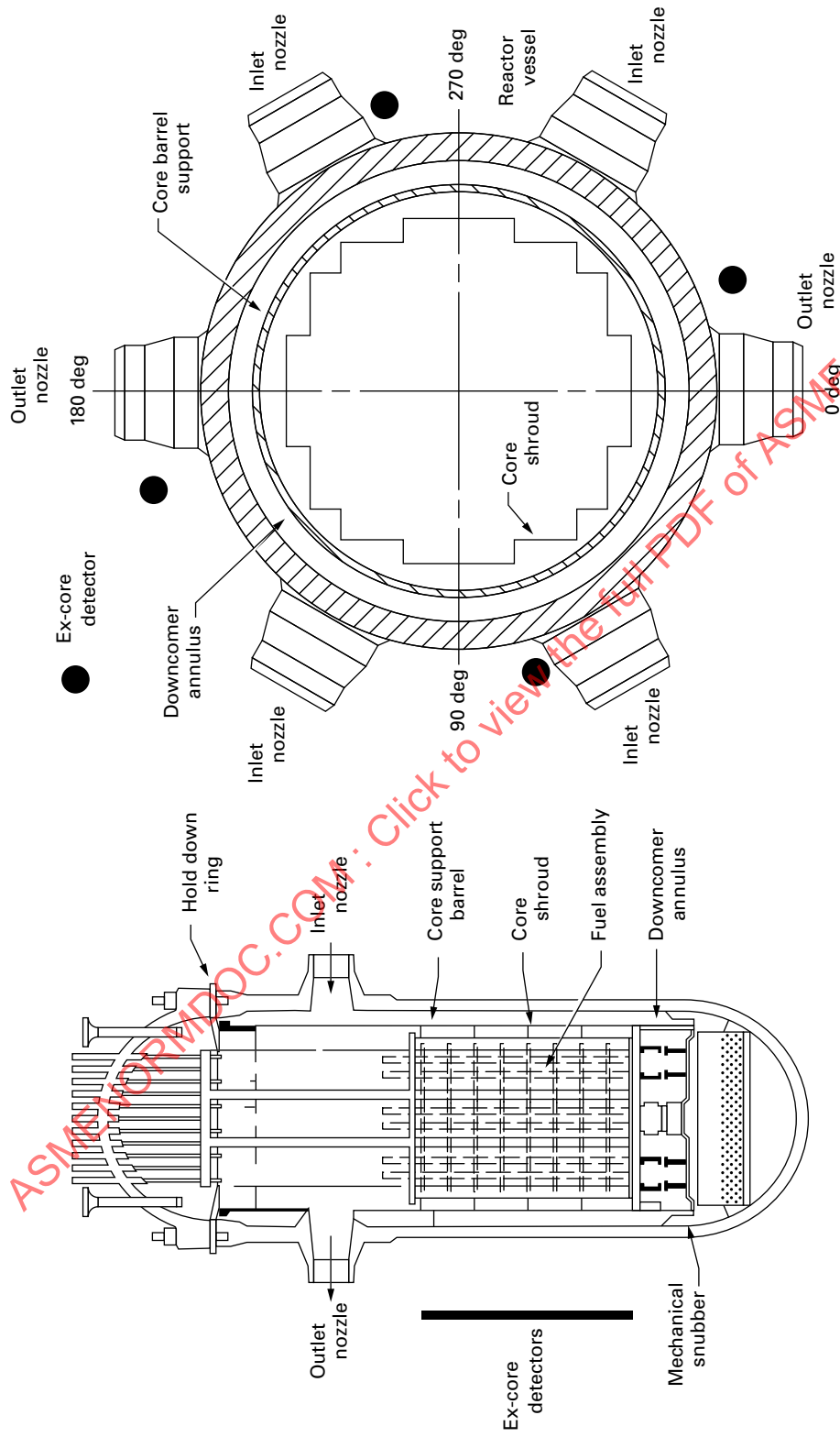
The normalized functions are defined in Nonmandatory Appendix B of this Part.

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 radial gap between the inner diameter of the reactor vessel and the outer diameter of the core barrel (downcomer annulus water gap), and the variation in this water gap will result in corresponding variations in the neutron flux sensed by the detectors [see Figure 1, illustration (b)].

The ex-core neutron flux signal is composed of a direct current (DC) 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

Figure 1
Reactor Arrangement Showing Typical Ex-Core Detector Locations



(a) Reactor Arrangement

(b) Ex-Core Detector Locations

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 Figure 1) provides a 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 of this Part.

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. Obtain baseline data 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, obtain baseline data 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. Obtain data at the start of each fuel cycle and every 90 effective full-power days (90 EFPD) or less throughout the cycle. Initiate the diagnostic phase of the program 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 is used to identify the cause and evaluate the significance of unexpected changes in the neutron noise signals identified in the surveillance phase. The phase requires 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 sections 4 through 6. A summary of the program phases is shown in Table 1. Data reduction techniques are discussed in Nonmandatory Appendix B of this Part. Data acquisition information (instrumentation, signal conditioning, parameters, and plant conditions) is discussed in Nonmandatory Appendix C of this Part. Data evaluation (including use of acquired data, anomalies, and other experience) is presented in Nonmandatory Appendix D of this Part. Guidelines for evaluating baseline signal deviations (including data trends and user experience made available since the original release) are discussed in Nonmandatory Appendix E of this Part. Representative data are shown in Nonmandatory Appendices D and E of this Part.

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

Collect data for use in establishing the reference database

(a) at the beginning, middle, and end of each of the first three fuel cycles of a new plant

(b) at the beginning, middle, and end of the first fuel cycle after the program is applied in a plant that is already operating

(c) after every core barrel removal

(d) after every significant modification to the core

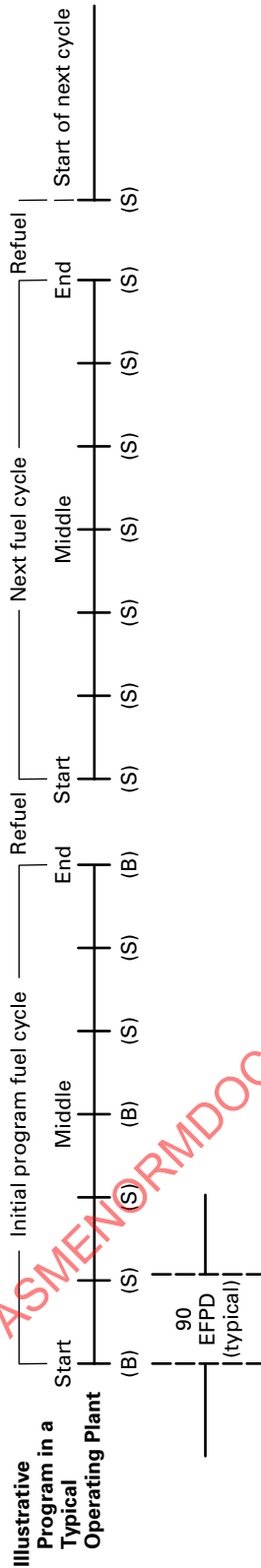
(e) after every significant modification of the reactor internals

Acquire data 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

Record 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) at each baseline phase data acquisition period. As a minimum, analyze the data to determine the following:

Table 1
Summary of Program Phases



Program Phase	Frequency of Data	Data Acquisition	Data Reduction	Data Evaluation	Action
Baseline (B)	New plant: startup, middle, and end of first three fuel cycles 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, NCPD, 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 rms 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 two pairs of cross-core detectors separated by approximately 90 deg	NCPD for two cross-core pairs of detectors separated by approximately 90 deg wide- and narrow-band rms, or narrow-band rms 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

- (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 elevation. If detector signals are available at more than one elevation, it is permissible to select detector and detector pairs from more than one elevation, but signals used for a pair should be from the same elevation. Monitor, as a minimum, two sets of cross-core (separated by 180 deg) detectors.
- (d) wideband and narrowband nrms values for frequency bands as defined in para. 4.4.

Analyze the data 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 detected (see Nonmandatory Appendix C of this Part). Maintain the plant as close as possible to expected steady-state operating conditions during data acquisition.

4.4 Data Evaluation

Use the baseline data 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. Ensure the narrowband range encompasses approximately $\pm 25\%$ of the beam mode center frequency for the core support barrel. Adjust this band 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 of this Part). Verify the center frequency of core barrel motion 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 (a) or (b)

Establish a wide-band frequency range from 0.2 Hz to a minimum of 20 Hz that includes, as a minimum, responses in all anticipated support conditions.

Determine baseline nrms values for both frequency ranges and beam mode center frequencies 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. Use periodic measurement and analysis or a suitable continuous surveillance monitoring system. Conduct the program for each fuel cycle over the life of the plant.

5.2 Frequency of Data Acquisition

Acquire and evaluate the data associated with the surveillance phase

- (a) at the beginning of each fuel cycle
- (b) at intervals of 90 effective full-power days or less
- (c) at the end of each fuel cycle

Baseline data may be acquired in lieu of surveillance data.

5.3 Data Acquisition and Reduction

Acquire and evaluate the data by either of the two means identified in para. 5.1. Determine the values of nrms and center frequencies from NCPSDs using pairs of cross-core (separated by 180 deg) detectors. Use detector pairs separated by approximately 90 deg. In addition, acquire data to permit preparation of coherence and phase for two cross-core detector pairs at a later time. Acquire data 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

Compare the narrowband and wideband nrms values or narrowband nrms and core support barrel beam mode vibration frequency(ies) to corresponding values established during the baseline phase. Establish the acceptable range of nrms values and beam mode center frequency(ies) by the plant Owner. Allowances may be made for gradual changes in nrms and beam mode center frequency values due to nonmechanical phenomena. Progress to the diagnostic phase if the nrms values or resonance frequency fall outside the acceptable range.

Guidelines for establishing criteria for entering the diagnostic phase of the program are given in Nonmandatory Appendix D of this Part.

6 DIAGNOSTIC PHASE

6.1 Objective

The diagnostic phase of the program is entered when surveillance phase data evaluation determines that limits are exceeded. The objective of this phase of the program is to establish if 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

Contrast the NPSDs, NCPSDs, coherences, and phases to data recorded during the baseline and surveillance program phases. Use the results of these comparisons and other observations (see Nonmandatory Appendix D of this Part) to indicate whether further data acquisition

or analyses shall be undertaken. Establish the trend of deviations, and use these results to define the frequency of further data acquisition that will provide adequate indication of changes that are of sufficient magnitude to warrant further action.

6.3 Data Acquisition, Reduction, and Evaluation

Contrast the NPSDs, NCPSDs, coherences, and phases to data recorded during the baseline and surveillance program phases. Use the results of these comparisons and other observations (see Nonmandatory Appendix

D of this Part) to indicate whether further data acquisition or analyses shall be undertaken. Establish the trend of deviations, and use these results 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 of this Part).

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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 noise 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

$$\frac{\phi_d - \phi'_d}{\phi_d} = 1 - (e^{-\Delta X \Sigma_r})$$

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

$\text{NPSD}(\omega)$ = 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 ($\bar{\phi}_d$)

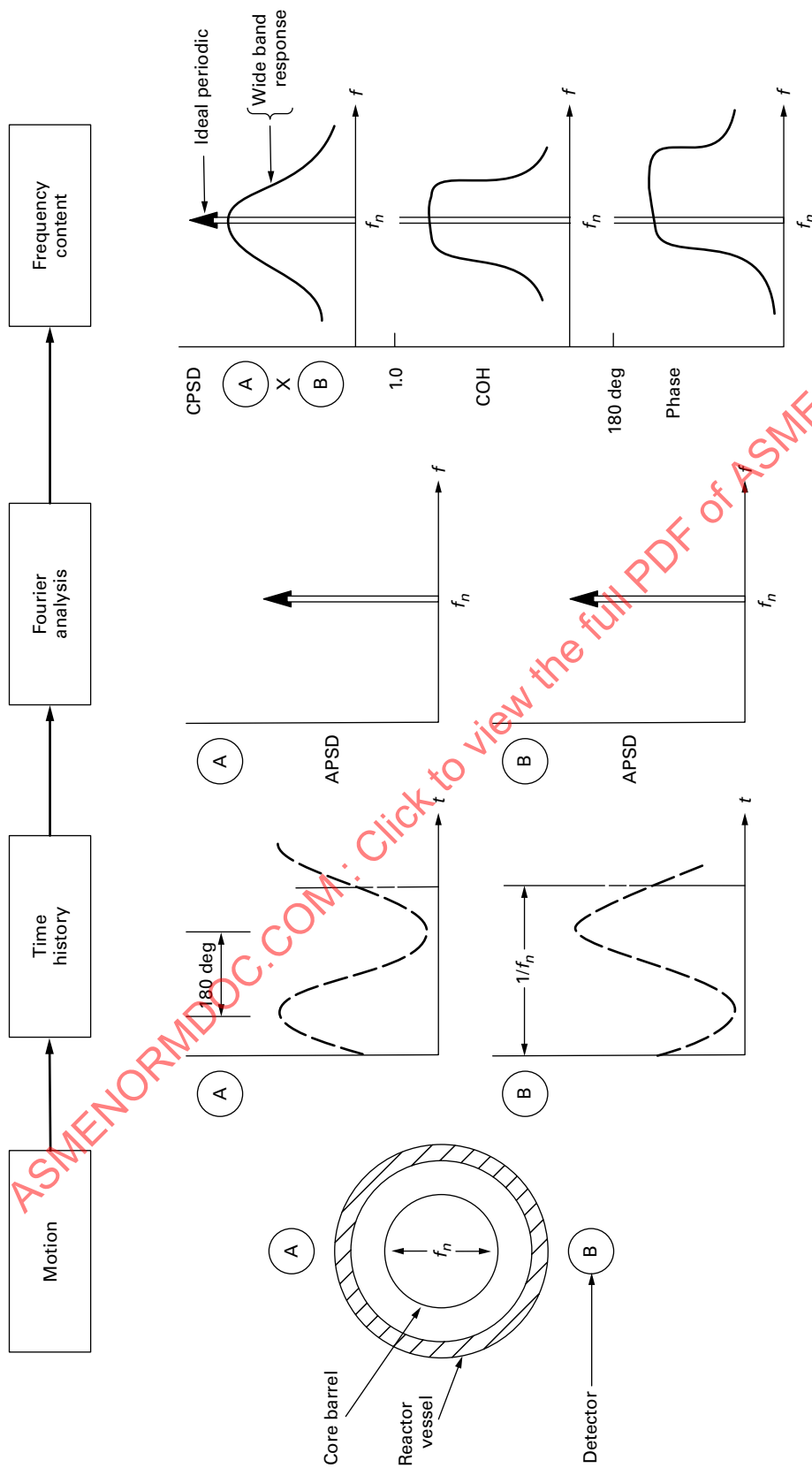
$$= \text{PSD}(\omega) / \bar{\phi}_d^2$$

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 of this Part. 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 Figure A-1.

More complete reviews of the relationship between ex-core detector signals and internals motion appear elsewhere [4, 5].

An overview of experience with excore monitoring of core barrel motion also appears elsewhere [1, 6, 7].

Figure A-1
Idealized Analysis for Core Barrel Motion



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 [8]. 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 [Figure B-1, illustration (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 bandwidth.

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.

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 (NCPD), COHERENCE (COH), AND PHASE (ϕ)

B-3.1 Normalized Cross-Power Spectral Density (NCPD)

The NCPD (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 [Figure B-1, illustration (b)]. The ability of the NCPD 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:

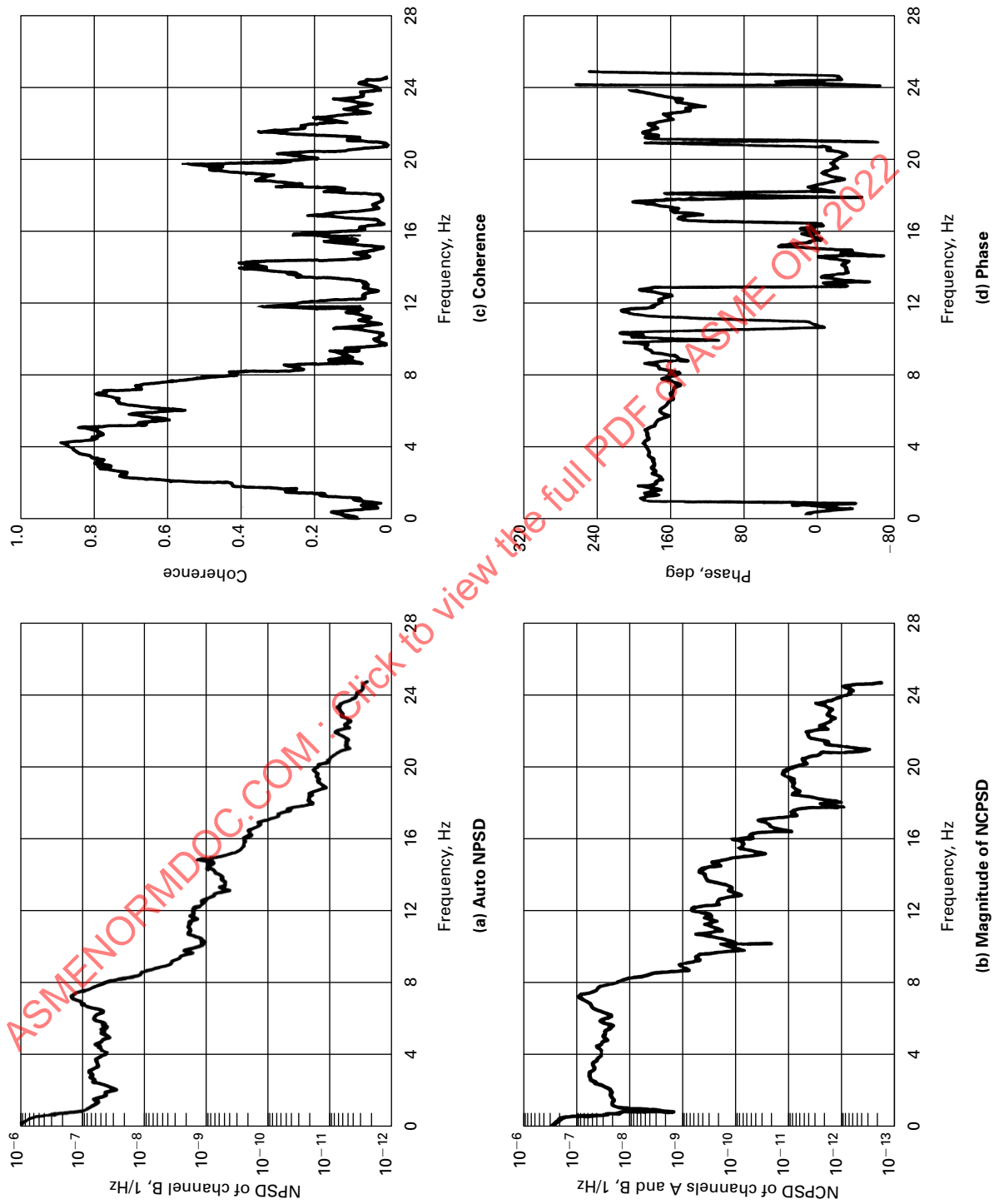
$$(\text{nrms})^2 = \int_{f_1}^{f_2} \text{NCPD} df$$

The NCPD 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 NCPD 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 [Figure B-1, illustration (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 [Figure B-1, illustration (d)]. Coherence is dimensionless, while phase is expressed in degrees.

Figure 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 section 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 bandwidth, 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 neither 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 [9]

$$-1/3(\Delta f/B_r)^2 \quad (C-1)$$

where Δf is the analysis frequency resolution and B_r is the true (unbiased) half-power bandwidth 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 (Y^2) follow the following formula:

$$\hat{Y}^2 - Y^2 = \frac{1}{n_d}(1 - Y^2)^2 \quad (C-2)$$

where n_d is the number of ensemble averages, Y^2 is the true coherence, and $\hat{Y}^2$ 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

$$\sigma_{\text{PSD}}/\widehat{\text{PSD}} = 1/\sqrt{n_d} \quad (C-3)$$

and in the CPSD by

$$\sigma_{\text{CPSD}}/\widehat{\text{CPSD}} = 1/\sqrt{Y^2 n_d} \quad (C-4)$$

where σ is the standard deviation and $\widehat{\text{PSD}}$ and $\widehat{\text{CPSD}}$ are the mean values of the PSD or CPSD. For PSDs, this indicates that a single frequency estimate will have an uncertainty of $\pm 30\%$ at the 99% confidence (3 standard deviation) level for 100 ensemble averages.

The statistical error for the coherence [10]

$$\frac{2\hat{Y}^2}{n_d} \left(1 - \hat{Y}^2\right)^2 \quad (C-5)$$

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.

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 narrowband and wideband frequency ranges or the narrowband 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 reevaluate baseline nrms values more frequently than the minimum schedule given in para. 4.2.

To establish the narrowband 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 $\pm 25\%$ of the center frequency is used to bound the narrowband region as shown in Figure D-1, illustration (a). Adjacent peaks may be omitted from the narrowband region as shown in Figure D-1, illustration (b). These methods may be used to define the narrowband rms baseline value for either a continuous or a periodic monitoring system.

Small changes may be found in the amplitude and/or center frequency, as shown in Figure D-1, illustration (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 wideband (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, wideband nrms values versus burnup should display a linear trend (Figure D-2) [11]. Significant changes from this trend would warrant a diagnostic phase investigation of the signal.

D-1.2 Normalized Power Spectral Density (NPSD)

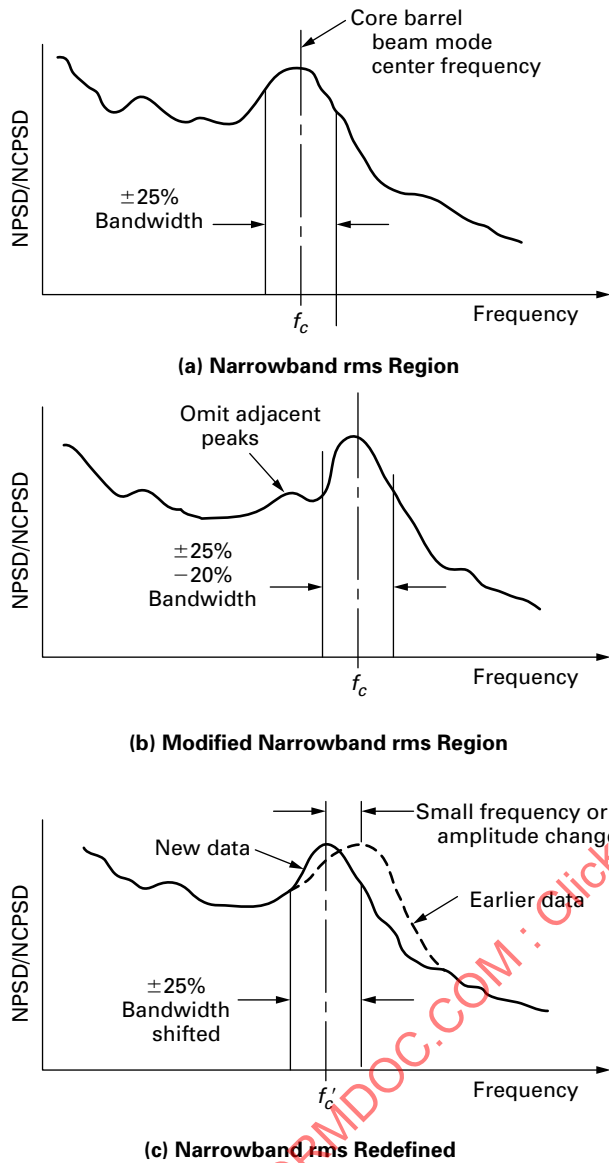
The NPSD of an excore detector signal contains contributions due to actual motion and extraneous noise. As such, while its frequency spectra may be a good indicator of the frequency of motion, its amplitude will be higher than that due to the motion. Recognizing this limitation, the NPSD signal of each 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).

Figure D-1
Narrowband rms



D-1.3 Normalized Cross-Power Spectral Density (NCPD), Coherence (COH), and Phase (ϕ)

The characteristic that the NCPD 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 [12]. These data need to be carefully evaluated along with the NPSDs to verify core barrel motion.

Baseline NCPDs 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 NCPD functions in the manner shown by Nonmandatory Appendix B of this Part 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 (NCPD)

NCPD 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.

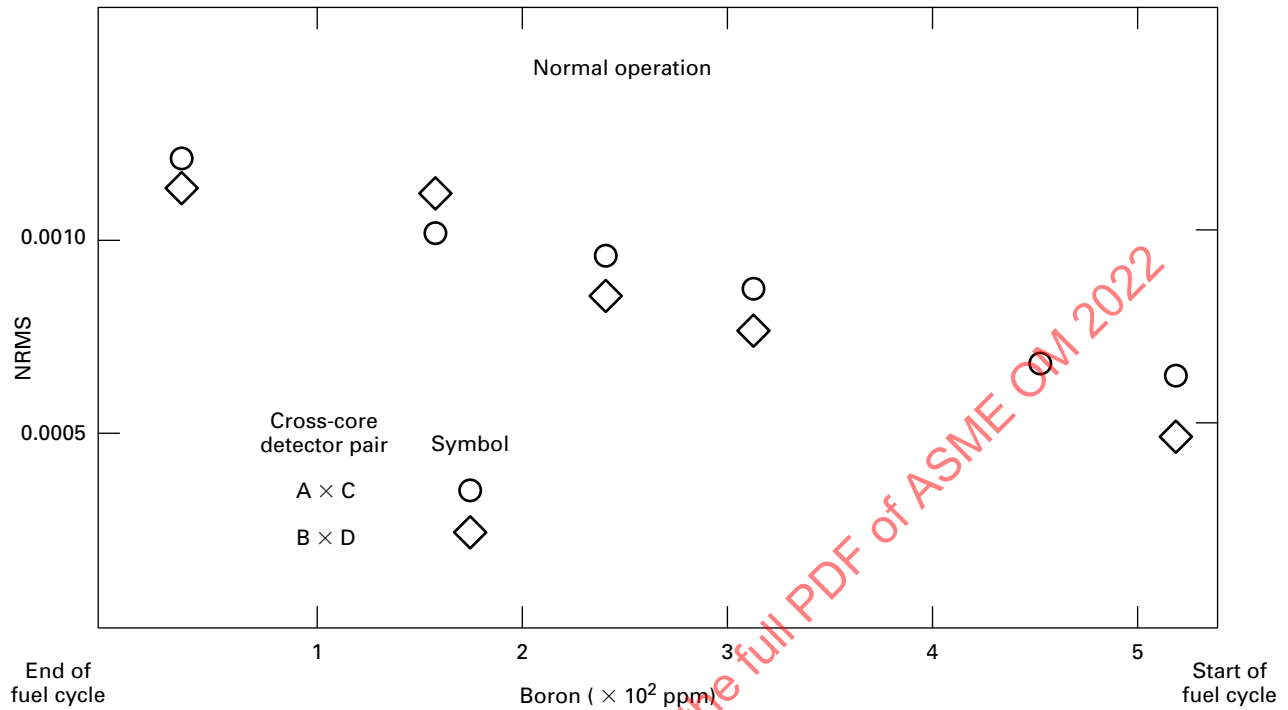
D-3 DIAGNOSTIC PHASE

D-3.1 Normalized Root Mean Square (nrms)

(a) The nrms value, as computed from the NPSD and NCPD, 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 narrowband ($\pm 25\%$ of the core barrel frequency) calculation of the rms value

Figure D-2
Example of Wideband rms Amplitude Versus Boron Concentration



based on the NCPSP 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 NCPSP.

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 (NCPSP), Coherence (COH), and Phase (ϕ)

The NCPSP, COH, and ϕ can be used in the diagnostic program to best ascertain the nature of the motion and determine if changes in wideband 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 rms 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 (Regulatory Guide 1.20)

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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 Figure E-1 with the corresponding range in power spectral density shown in Figure E-2 [7, 13]. Changes in the neutron noise signature over a fuel cycle, including refueling, are shown for one plant in Figure E-3 [7]. For comparison, a neutron noise spectrum from a plant with a loss of axial preload on the core support barrel flange is shown in Figure E-4 [14]. 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 [15].

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.

Figure E-1
Typical Ex-Core Neutron Noise Signatures From Six PWRs

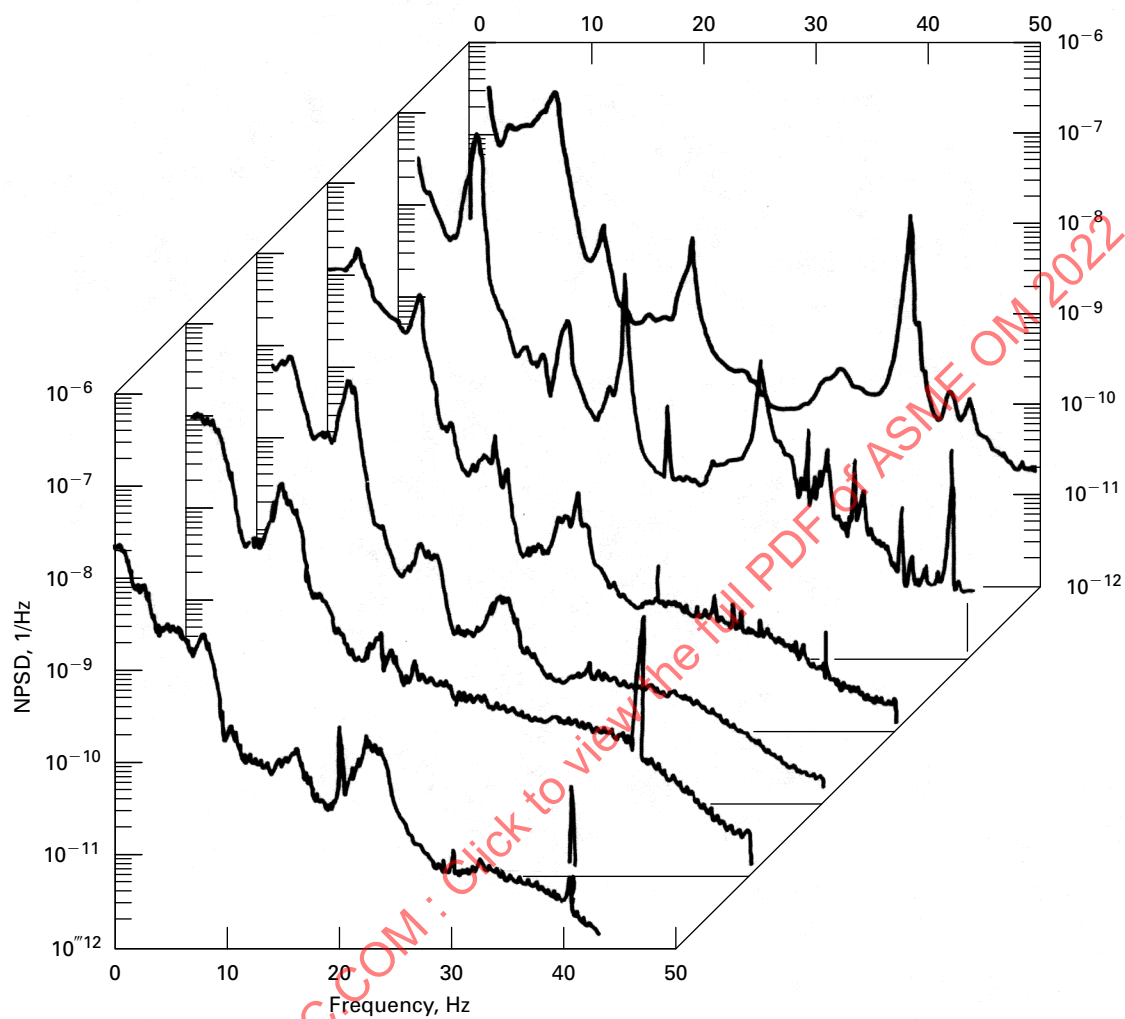
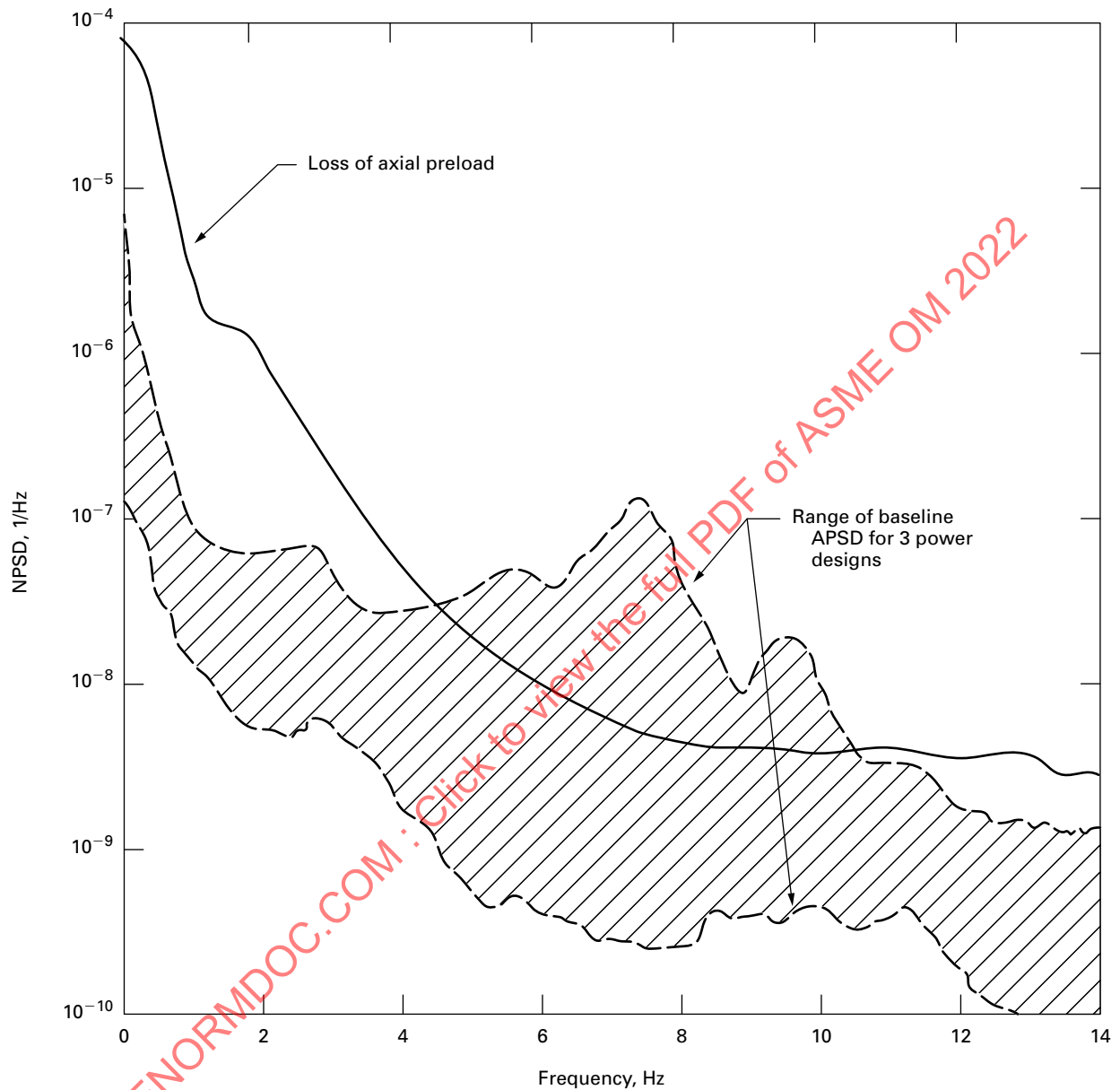


Figure E-2
Typical Baseline NPSD Range



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.

Figure E-3
Examples of Changes in the Neutron Noise Signature Over a Fuel Cycle

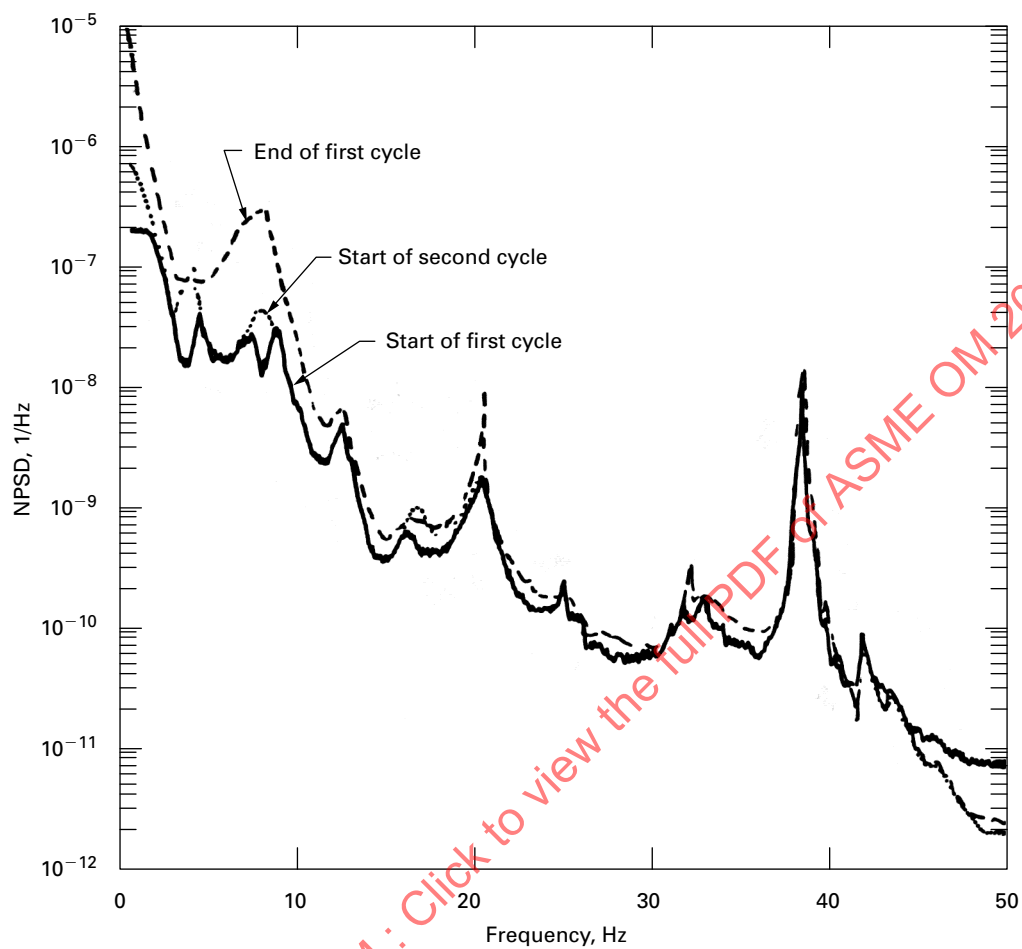
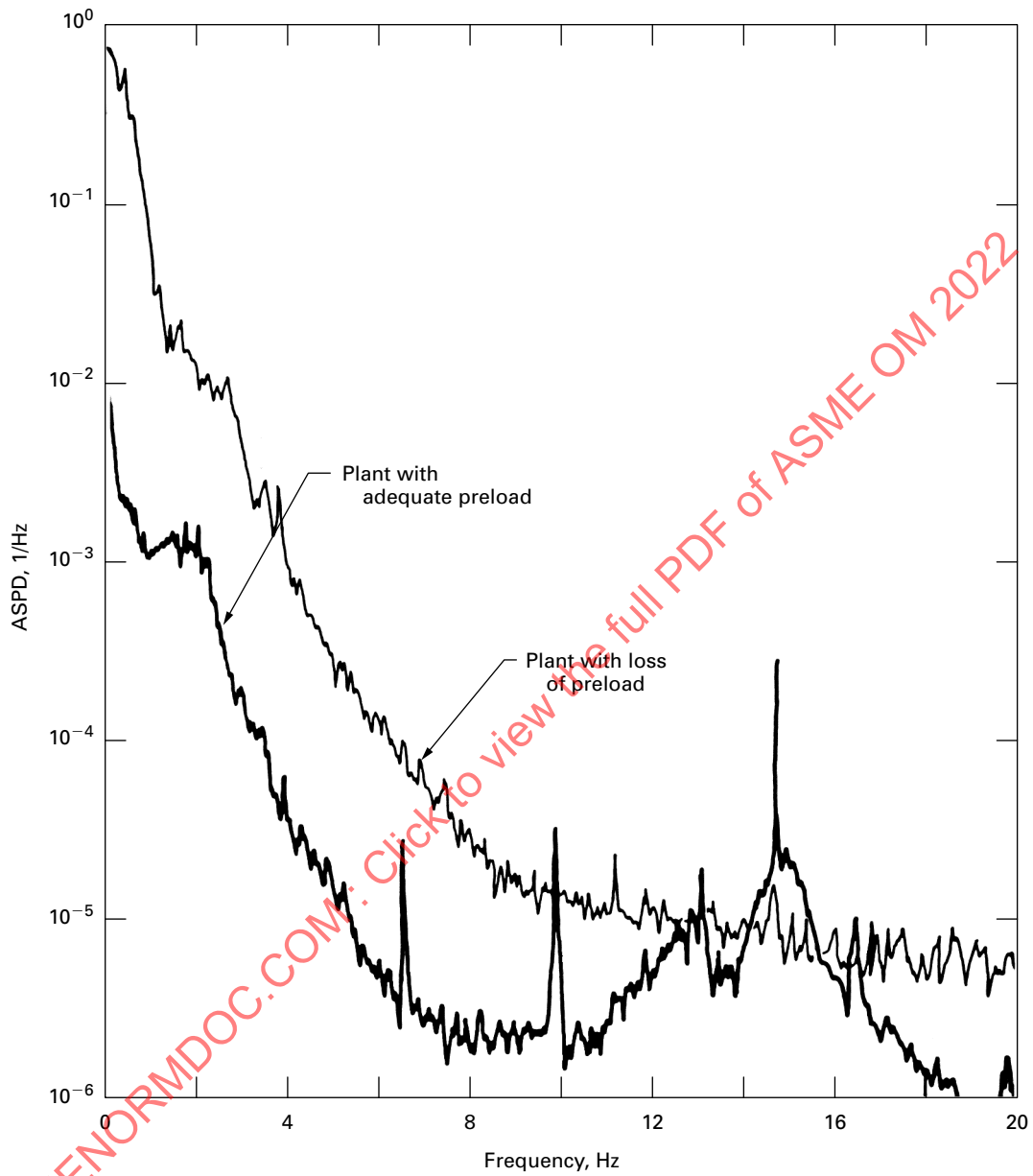


Figure E-4
Example of Loss of Axial Restraint



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 (e.g., fuel motion, burnup, soluble boron, and moderator density changes) may be significant [12]. 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.

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) [2]	Measured; based on change of neutron flux with temperature
0.0003 (0.012) [16]	Calculated; one-dimensional transport model
0.00043 ± 0.000064 (0.0185 ± 0.00661) [17]	Measurements based on ex-core detector and core barrel accelerometer transfer function
0.00025/0.00015 max. (0.0098/0.0059) [18]	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

Part 5, Nonmandatory Appendix G

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Part 7

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 water-cooled reactor nuclear 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.

BPVC: 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 ASME BPVC, 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 section 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 provisions 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 BPVC, 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 be consistent with 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 shall be specified in sufficient detail to ensure that the parameters and assumptions used in the analyses are consistent with those in the test. The correlation between test and analysis shall confirm the validity of the analysis.

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 shall be addressed 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 section 3 are satisfied.

(d) The locations selected for monitoring piping response shall be reflective of 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.

Evidence of the following shall also be evaluated in the tests:

(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 of this Part 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 shall be included in the evaluation of test results. Pipe wall temperature shall be measured at various points along the piping system to ensure that the system has attained the required test temperature. Equipment movements and nonuniform temperature distribution of system (e.g., branch piping with cold legs, thermal stratification, and thermal transients in applicable lines) shall be assessed 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, the need for performing an additional heat-up and cooldown cycle subsequent to the hot shimming to ensure correct system response shall be evaluated.

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 section 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 be based on 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 section 5) prior to acceptance of the test results. Reconciliation of the discrepant responses shall demonstrate that the requirements of section 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, such as

(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 section 5. Figure 1 depicts the steps involved in reconciliation and corrective action.

This paragraph provides acceptable 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
- (h) adverse impacts on adjacent systems, structures, or components

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 may 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 may 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 or component reactions. The acceptability of the evaluation shall be based on the criteria delineated in para. 3.2.

The provisions specified in para. 4.1 are also applicable to Reconciliation Method 2.

The simplified beam or computer models discussed in this paragraph are intended to result in conservative predictions of stresses and support and equipment loadings. Reconciliation Method 3 may be used to reduce 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

Figure 1
System Heatup, Reconciliation, and Corrective Action

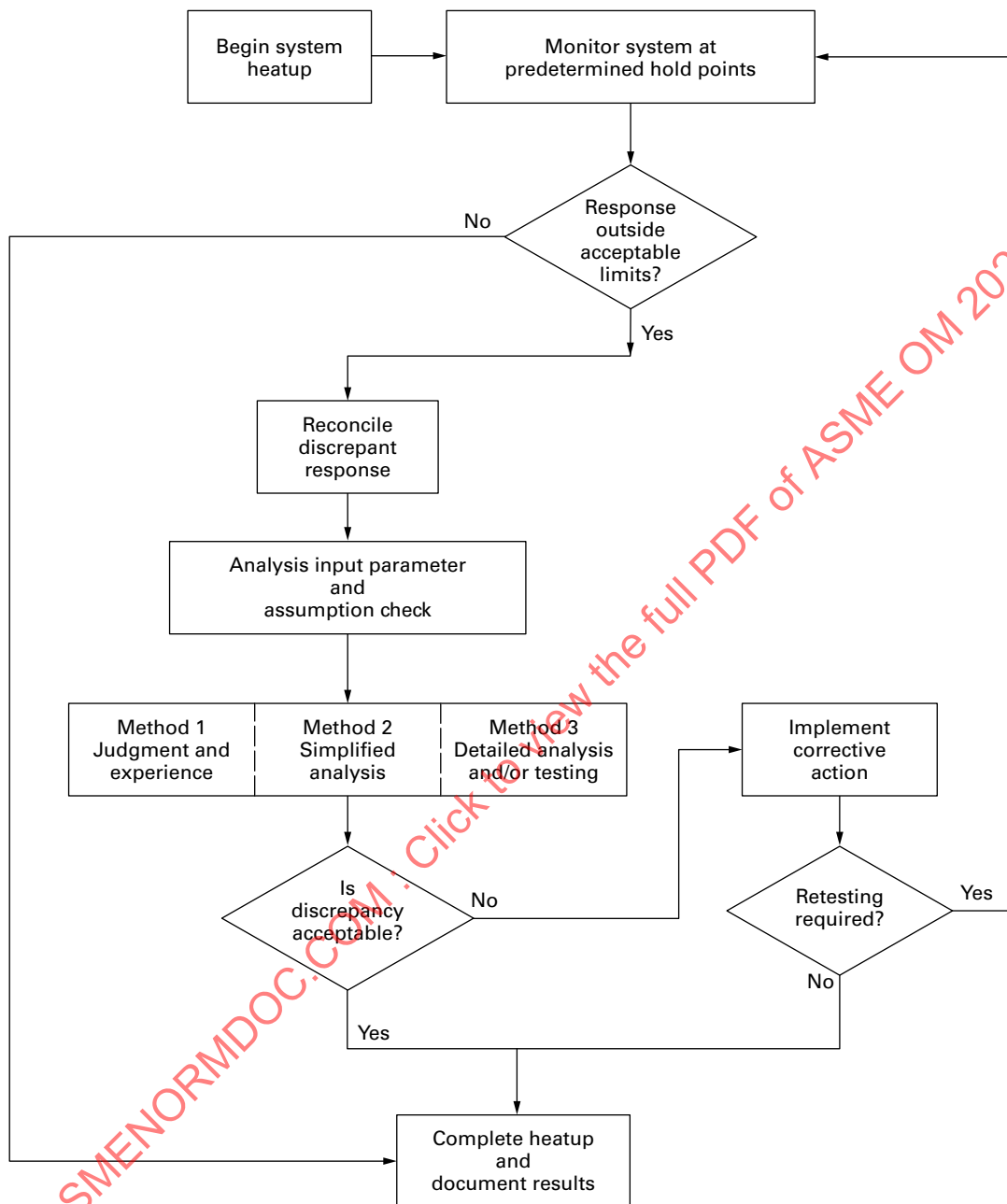
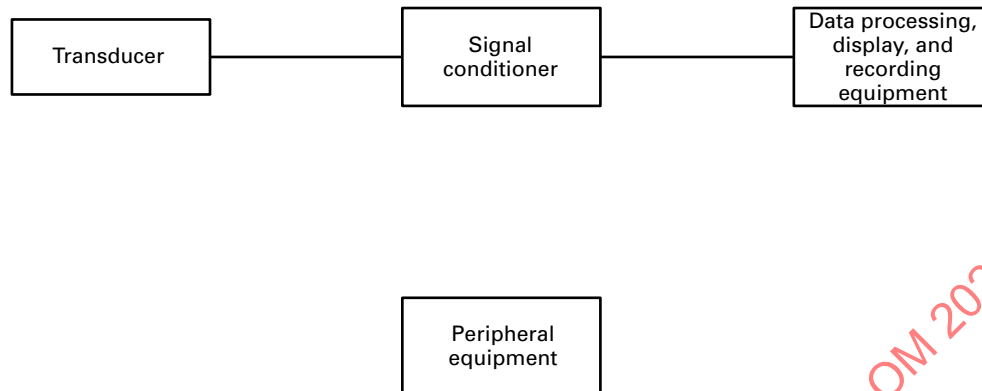


Figure 2
Typical Components of a TEMS



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 section 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 section is not intended to explicitly require certain instruments or techniques. Rather, this section 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 Figure 2.

Nonmandatory Appendix A of this Part contains guidelines and precautions for typical TEMS. Nonmandatory Appendix A of this Part may 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.

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:* $\pm 10\%$ of the minimum acceptable limit.

(h) minimum measurable value.

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. ($\pm 10\%$ 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. ($\pm 5\%$ of $D_{\min}$) (± 0.13 cm)
Frequency response	Static
Other (maximum pipe temperature)	300°F (149°C)

(1) *TEMS minimum requirement:* accurate readings from the TEMS shall 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 shall 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:* $\pm 5\%$ 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 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.

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 specifica-

tions. 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 shall be within minimum accuracy requirements of the TEMS specification.

6.1.4 Acceptability of Measurements. Measured data are 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 shall 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 may minimize the amount of retesting required.

Part 7, Nonmandatory Appendix A

TEMS Instrumentation and Equipment Guidelines

The purpose of this Appendix is to provide guidelines for the selection of components that comprise a thermal expansion measurement system (TEMS). Tables A-1 through A-3 are organized with respect to the generic basic components of the TEMS as described in section 6. For each typical device listed, information regarding such areas as function, application, and limitations is given as an aid in the selection process.

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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 $\frac{1}{16}$ 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	A linear variable differential transformer 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 proximator 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
Laser displacement sensor	An optical sensor that projects visible laser light on a target and uses the reflected light from the target to compute the target's distance from the sensor	Provides high accuracy resolution Accuracy is dependent on distance from target and reflectivity of target
Infrared thermometer	A noncontact temperature measurement device	Convenient, easy to use Accuracy is dependent on distance-to-target size ratio

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 either within 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 Data Processing, Display, and Recording 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.
A/D converter (with computer)	Converts the analog signals to a digital format for processing, display, and storage	A/D parameters specified in software
Computer	Contains hardware and software for processing, display, and storage	Has greatly expanded processing and output capabilities compared to a data logger

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 Figure 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.

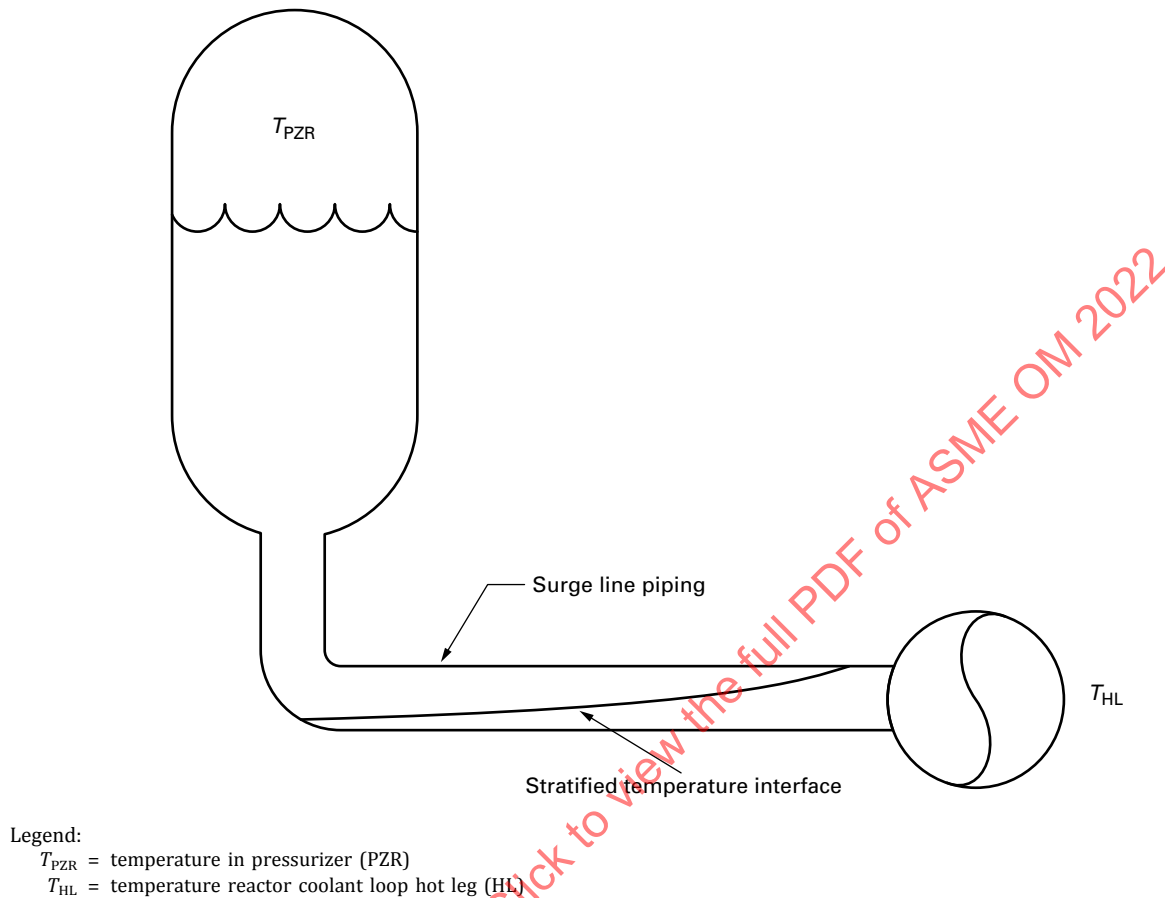
The differences in temperatures cause the pipes to assume a circumferential temperature gradient. This gradient causes the pipe to bow, typically in the vertical plane. This vertical bowing can create unanticipated internal forces and horizontal or vertical movement in a complex three-dimensional piping 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 stream 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

Figure B-1
Simplified Schematic of Surge Line Stratification



reduced. The large difference in temperature coupled 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, as follows:

- (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

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Part 12

Loose Part Monitoring in Water-Cooled Reactor Nuclear Power Plants

1 INTRODUCTION

1.1 Scope

This Part establishes the requirements for loose part monitoring in water-cooled reactor nuclear 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.

Section 2 defines the terms used in this Part; because loose part monitoring is unique, some terms may deviate from definitions used in other Parts. Section 4 deals with loose part monitoring system instrumentation and its installation; it is intended that section 4 serve as the basis for the design and installation of new or replacement systems. Section 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/sec² (9.81 m/s²).

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.

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

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

LPM: loose part monitor.

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 Methods 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 (www.ansi.org)

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, U.S. Government Printing Office (GPO), 732 N. Capitol Street, NW, Washington, DC 20401 (www.gpo.gov)

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 Figure 1. However, impacts farther from the accelerometer (typified by the one shown in Figure 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 Figure 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 Figure 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 $\pm 15\%$ 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 $\pm 10\%$ 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 Figure 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.

Figure 1
Typical Broadband Sensor Response to Nearby Impact

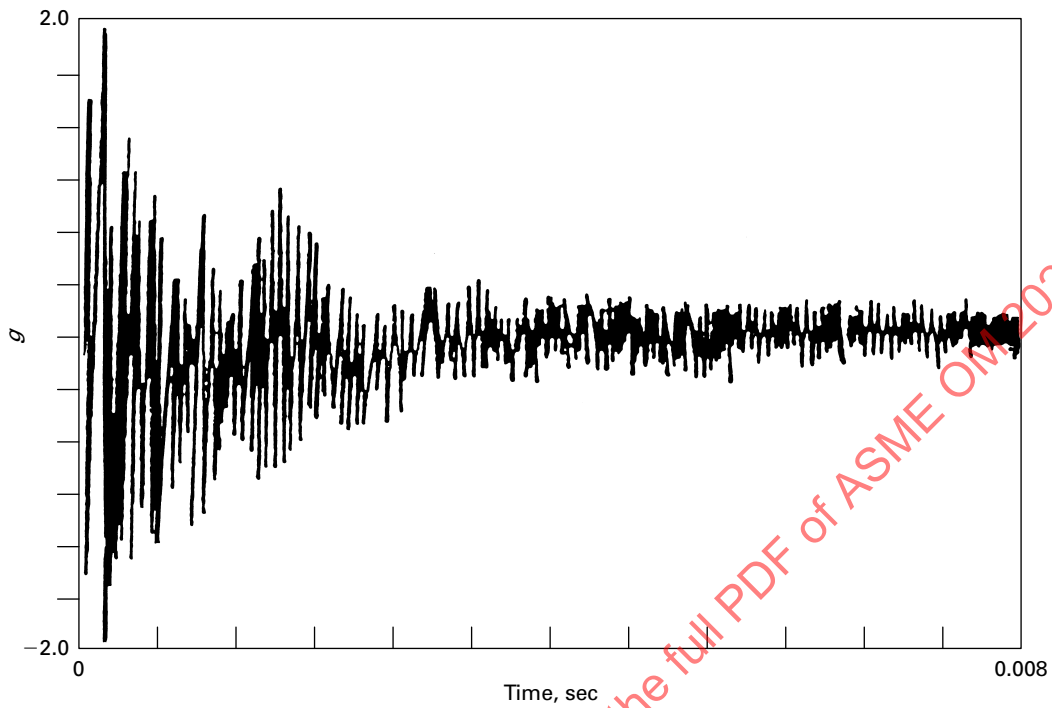


Figure 2
Typical Broadband Sensor Response to More Distant Impact

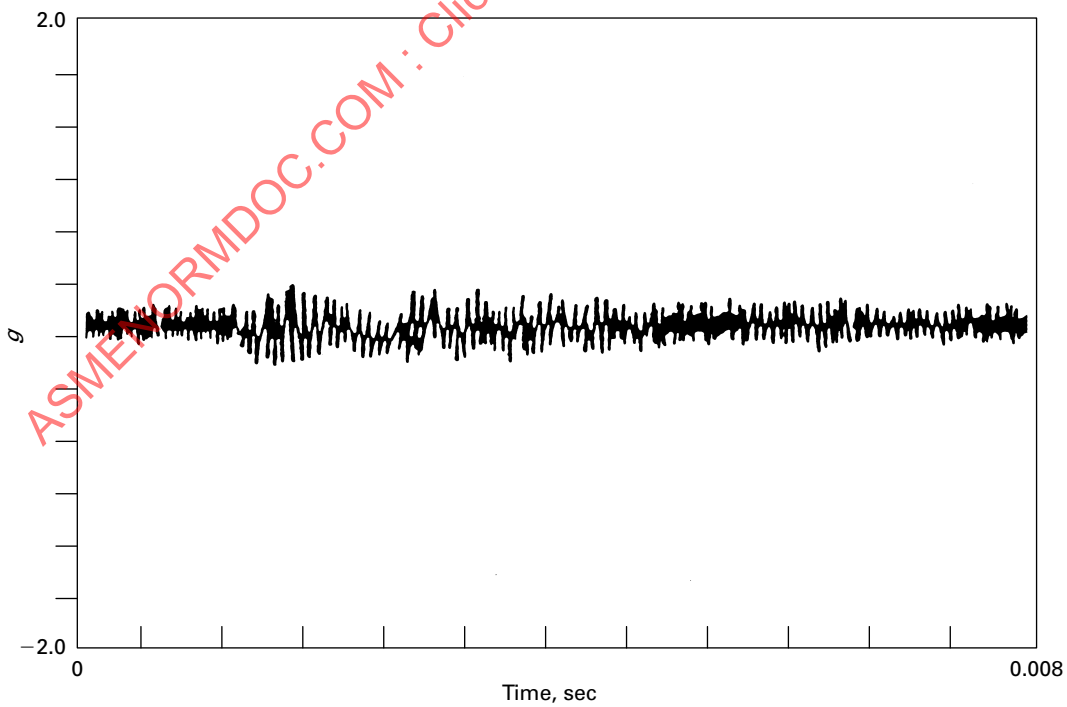


Figure 3
Range of Loose Part Signal Amplitude and Predominant Frequency Content

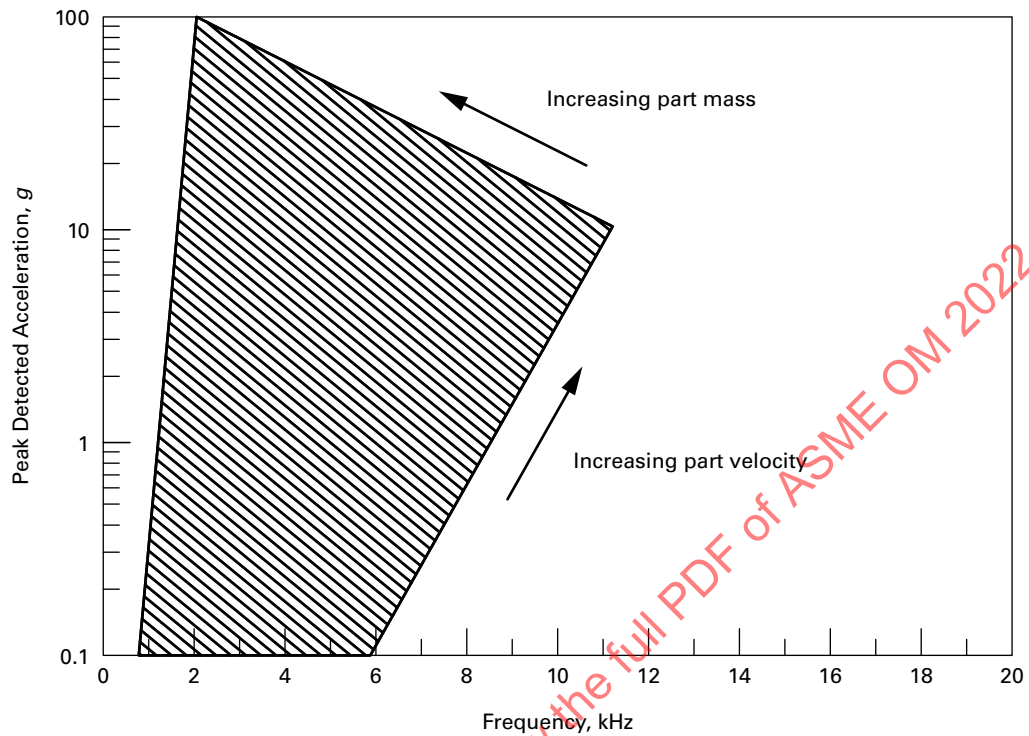
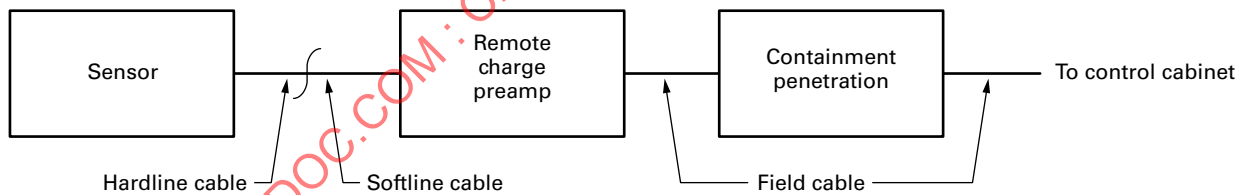
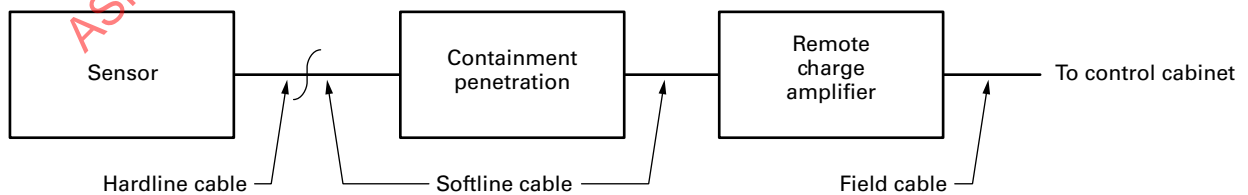


Figure 4
Field Equipment



(a) For Remote Charge Preamp Inside Containment



(b) For Remote Charge Amplifier Outside Containment

Figure 5
Direct Stud Mount

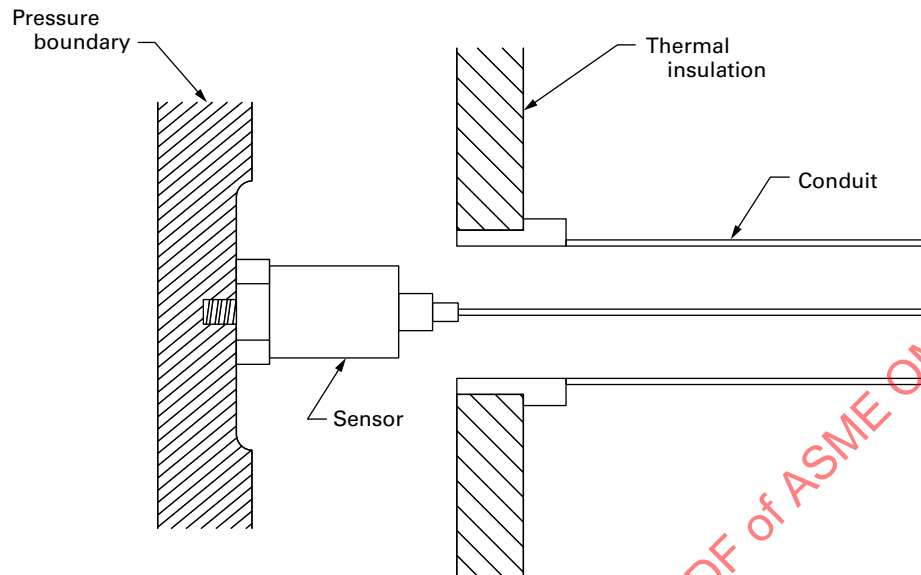
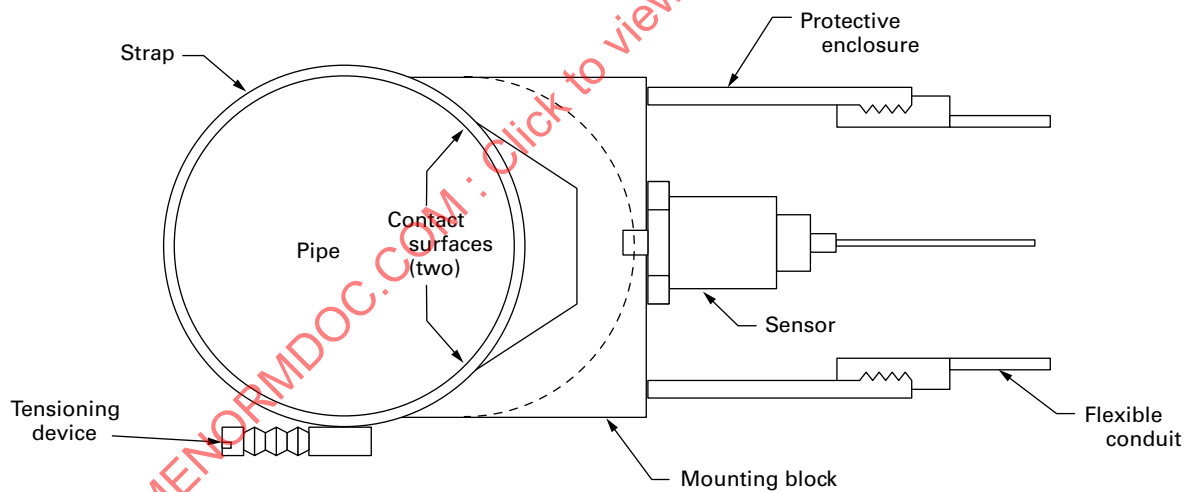


Figure 6
Clamped Mount



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 $\mu\text{in.}$ (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.

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

(i) Clamped fixtures mounted on cylindrical surfaces shall have a two-line contact surface similar to that shown in Figure 6.

(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 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, feed-water 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.

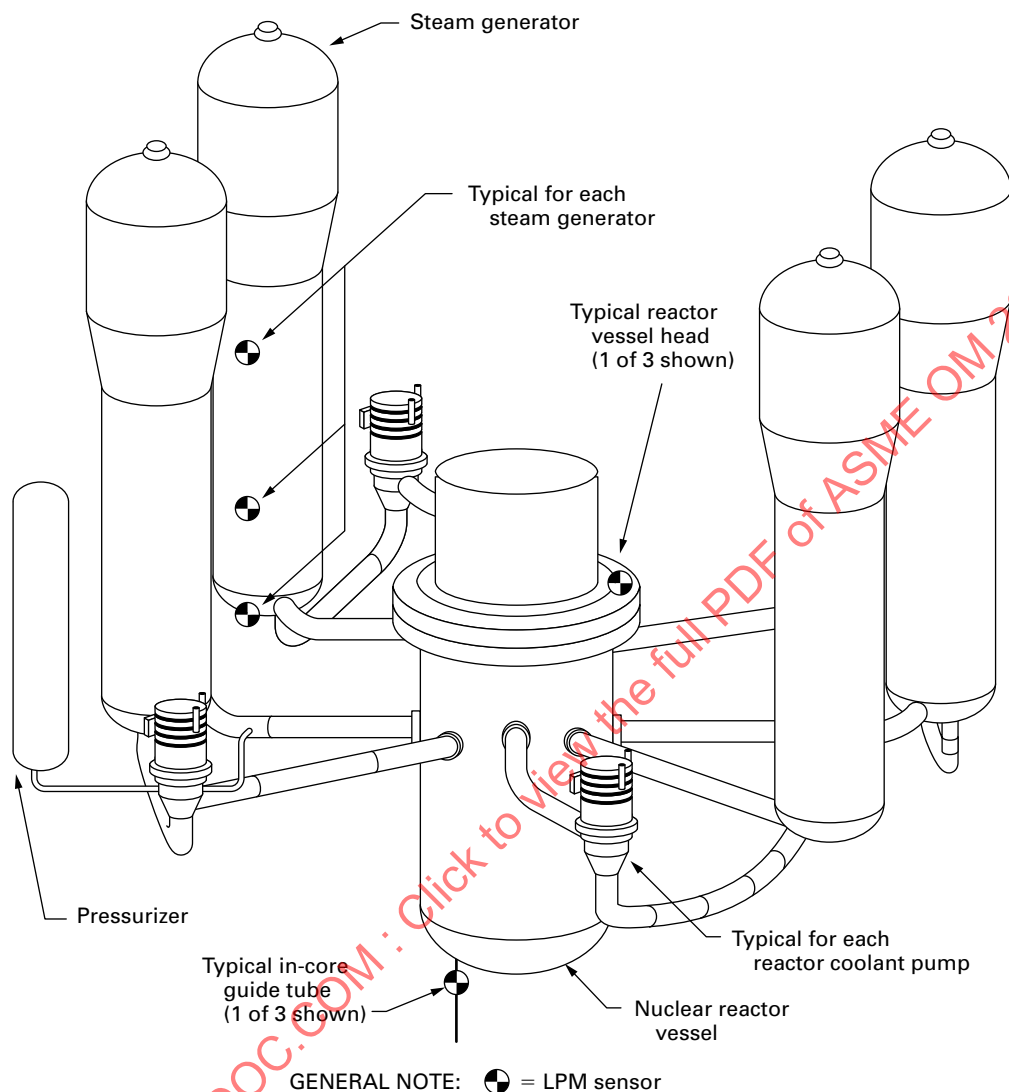
Install one accelerometer on each recirculation pump. The sensor should be mounted to a lifting lug or other location on the pump bowl. The location should be selected to avoid sensor damage during pump maintenance. Install one accelerometer on each recirculation loop discharge pipe near the recirculation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

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



radiation from withdrawn in-core 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 $\pm 5\%$ 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

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

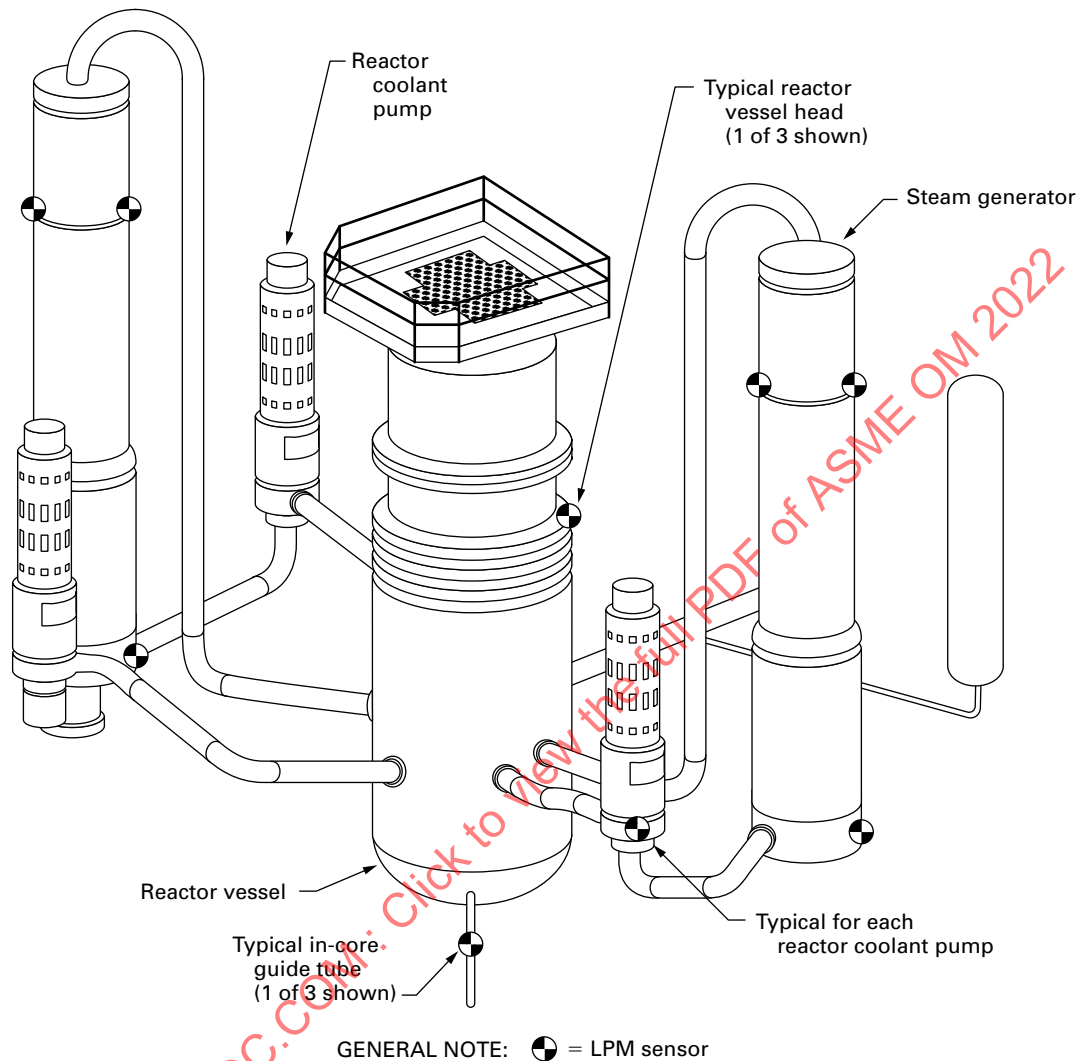


Table 2
Recommended BWR Accelerometer Locations

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

requirements for remote charge converters. Remote charge amplifiers shall meet the following requirements:

(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 $\pm 5\%$ from 5 kHz to 20 kHz

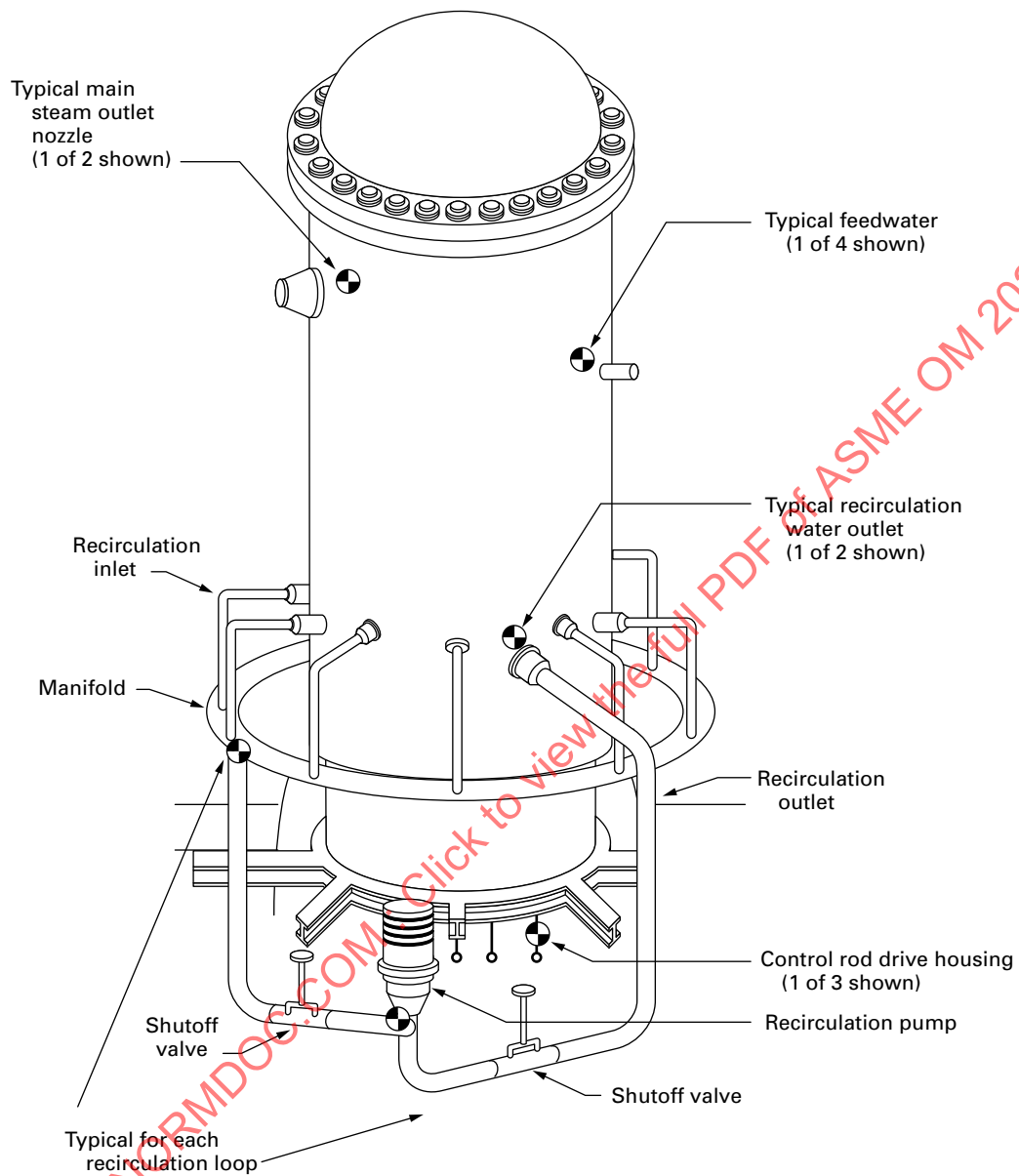
(d) input resistance and capacitance: compatible with combined accelerometer/sensor cable values at maximum operating temperature

(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

Figure 9
Recommended Sensor Array for BWR



GENERAL NOTE:  = LPM sensor

4.3 Control Cabinet Equipment

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

- (a) Frequency response: flat within $\pm 5\%$ 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 .
- (f) Over-range and under-range indication (unless provided in either the detector or the 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.
- (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 para. 4.2.5

(b) Continuous Analog Recorder

- (1) frequency response: flat within $\pm 5\%$ from 1 kHz to 10 kHz, recommended to be flat within $\pm 10\%$ 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 para. 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 para. 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

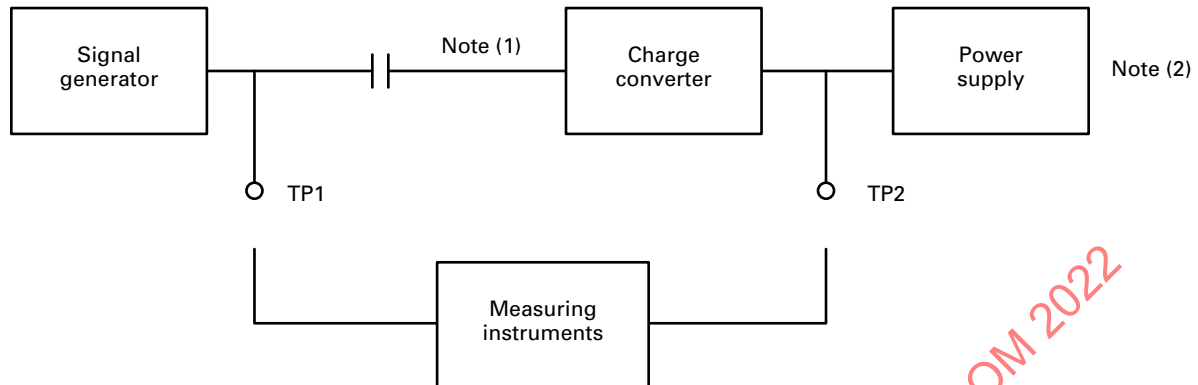
High voltages may be encountered during procedures specified in this section; therefore, care must be taken to protect both personnel and equipment from shock hazards and electrostatic shock damage. Accelerometer signal leads or cables attached to accelerometers should be shunted to ground before connection 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.

Figure 10
Block Diagram for Charge Converter Calibration Tests



NOTES:

- (1) 1,000 pF typical; consult charge converter vendor for specifics.
 (2) Use LPM signal conditioner if possible.

(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 Figure 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 $\pm 5\%$. 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 Figure 11.

Do not use more than 50 V in determining resistance. Use either a bridge-type instrument or a 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 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 Figure 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 $g/\text{Hz}^{1/2}$ 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 $g/\text{Hz}^{1/2}$.

(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 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).

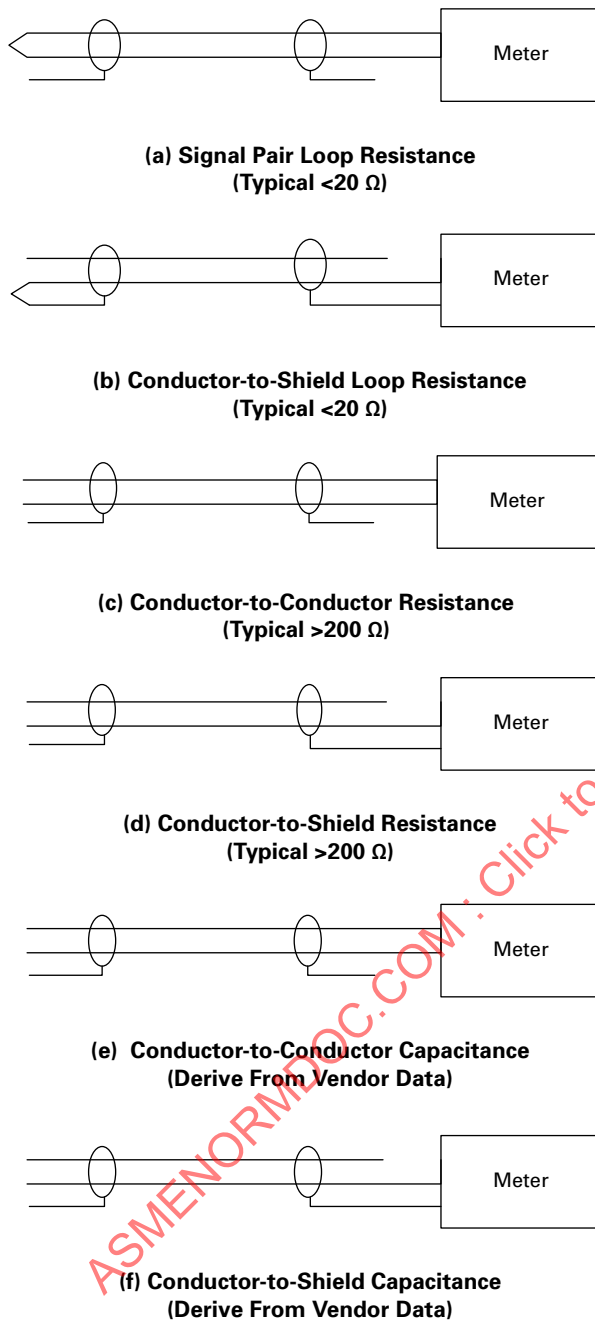
5.6 Initial LPM Setpoints

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 3 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

Figure 11
Cable Properties
(Typical for Twisted-Shielded Pair Cable)



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 setpoints (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, broadband 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.

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Part 12, Nonmandatory Appendix A

References

ANSI S2.10-1971, American National Standard Methods 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

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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

Performance Testing and Monitoring of Standby Diesel Generator Systems in Water-Cooled Reactor Nuclear 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 water-cooled reactor nuclear 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

This Part provides guidance on the performance of periodic testing to demonstrate the operational readiness of a standby diesel generator.¹ In addition, material condition-monitoring methodologies, e.g., engine component operating parameters trending, engine analysis, vibration analysis, lube oil analysis, fuel oil analysis, cooling water analysis, and thermography, should also be considered for assessing the health of the diesel generator system. Since all diesel generator systems are not identical in design, there may be variations to specific recommendations in this document. This Part covers both pre- and post-2000 plants.

1.3 Risk-Informed Analysis

This Part covers both safety-related and non-safety-related diesel generator systems. Owners must categorize each diesel generator system according to its safety significance using the ASME-approved risk-informed methodology or other risk ranking methodologies accepted by the regulator with the conditions in the applicable safety evaluations.²

¹ The prescribed tests in this Part are consistent with the requirements specified in U.S. NRC Regulatory Guide 1.9, Revision 4 and IEEE 387-1995 (reaffirmed September 2007), Section 7.4, "Periodic Testing."

² For U.S. plants, the implementation of Code Case OMN-3 included the conditions discussed in Regulatory Guide 1.192.

1.4 Subsystems Included Within the Diesel Generator Boundary

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 generator and subsystem boundary. As the engine cannot be tested independently of the generator, the owner/operator must consider the effects of inservice testing on the entire system (the diesel engine and the associated subsystems).

Typical principal equipment for associated diesel generator subsystems identified in Figure 1³ are listed below for owner/operator considerations in the development of a preventive maintenance program. The owner/operator established standby diesel generator maintenance program should account for site-specific and relevant industry operating experience, and be consistent with the recommended periodic maintenance of the manufacturer or as developed by the respective diesel engine owners group.

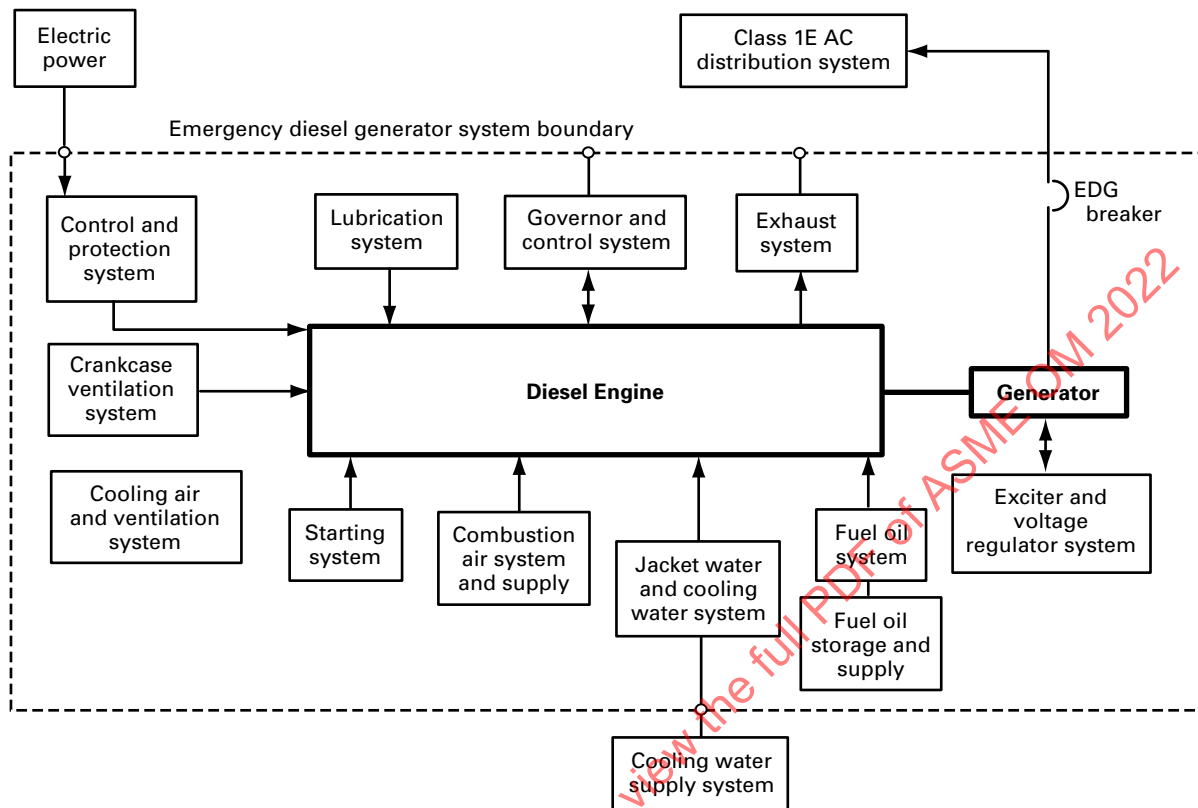
1.4.1 Engine. Equipment includes (where applicable) the following:

- (a) crankcase
- (b) crankshaft and bearings
- (c) power assemblies
- (d) valve gear
- (e) camshafts and bearings
- (f) damper
- (g) gear trains
- (h) flywheel

1.4.2 Lubrication Subsystem. Equipment includes (where applicable) the following:

³ Figure 1 is a system boundary diagram that shows the components of the diesel generator system. This is similar to the system boundary identified by U.S. NRC Regulatory Guide 1.9, Revision 3 and Revision 4, 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.

Figure 1
Boundary and Support Systems of Emergency Diesel Generator Systems



- (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

1.4.3 Jacket Water and Intercooler Subsystem. Equipment includes (where applicable) the following:

- (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, check valves, and block 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

1.4.4 Starting Subsystem. Equipment includes (where applicable) the following:

- (a) batteries/charging systems
- (b) electric/pneumatic start motors
- (c) air compressors
- (d) air receivers; relief, check, and air-start solenoid valves; and piping, tubing, and associated components
- (e) pressure-reducing valves, shuttle valves, block valves, check valves, and pressure regulators
- (f) air dryers, strainers, filters, 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

1.4.5 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, ductwork, 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)

1.4.6 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, ductwork, connectors, bellows, joints, and associated components
- (e) instrumentation and controls

1.4.7 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 and filters
- (e) booster pump(s) and associated drive belt(s)
- (f) pressure-regulating, relief, check, transfer, and block 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

1.4.8 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

1.4.9 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) electronic fuel injection control
- (f) overspeed trip
- (g) instrumentation and controls

1.4.10 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

1.4.11 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 relays (components may not be located in the output breaker panel)
- (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 generator systems.

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 generator 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.

equilibrium temperature: the condition at which the diesel engine jacket water and lube oil temperatures are both within $\pm 10^{\circ}\text{F}$ (5.5°C) of the 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(s) that maintains jacket water, fuel oil, and/or lube oil temperatures at warm standby values recommended by the engine manufacturer.

major maintenance: corrective maintenance associated with disassembly and reassembly of engine components as part of an "open and inspect" maintenance practice. It also applies to the maintenance that returns the diesel engine to operating status following an abnormal event. Examples of such an event are crankcase explosion and piston-rod ejection.

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 engine.

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 NONOPERATING CHECKS

2.1 Post-Maintenance Checks

The owner/operator shall perform an initial check of the engine components and subsystems to provide reasonable assurance that the overall diesel generator unit will operate as designed. This check includes flushes, hydrostatic tests (if required following major repair/replacement activities) of fluid systems, visual checks, functional tests of support components and

systems, and additional tests as recommended by the manufacturer.

2.2 Pre-Start Checks

The owner/operator shall perform pre-start checks to provide reasonable assurance that the diesel generator will start and operate as designed without incurring equipment damage. These checks include engine fluid levels, engine pre-lube and keep-warm systems, governor control settings and oil level, starting air system pressure and line-up, generator bearing oil level, visual leak checks, engine bar over if applicable, and those additional inspections as recommended by the manufacturer.

3 TESTING

3.1 Post-Maintenance/Baseline Testing

The owner/operator shall perform testing post-maintenance on inservice engines that is above and beyond those normal maintenance-related tests specified by the diesel engine manufacturer. These tests shall be performed to demonstrate the starting and operational adequacy of the overall diesel generator unit. Note that the reliability tests for newly installed diesel generator sets described in IEEE 387-1995 (reaffirmed September 2007), Section 7.3, "Pre-operational Testing," do not apply since new unit reliability will have been established during initial type qualification testing. Section 4 of this Part lists the data that should be considered for engines that have had major maintenance performed.

Post-maintenance testing (PMT) is to verify that the diesel generator is capable of performing its intended function and to establish new performance baseline data where appropriate. PMT establishes current operational readiness and provides reasonable assurance of function in the future. Verification that a diesel generator is capable of performing its intended function may be accomplished by verifying that the applicable plant Technical Specification surveillance tests are re-performed after the maintenance activity. The owner/operator is required to establish the appropriate conditions to test a component to establish operability following maintenance.

The design function of the maintained component, potential failure modes (e.g., failure to pump, electrically operate), and conditions that may lead to a failure (e.g., vibration, operational cycles) must be considered when establishing the scope of the functional testing/PMT and the run duration. The diesel generator PMT run duration should be established based on the need to challenge components replaced or repaired during maintenance. Extended run duration is generally not effective in detecting fatigue-related failure mechanisms based on the low forcing function frequencies associated with diesel generator running speed. Once thermal equilibrium

has been reached, extended runs don't provide significantly more confidence that a failure won't occur during a subsequent run. Additionally, electrical components tend to fail during transients associated with changes of state.

3.1.1 General Testing Guidance for Diesel Generator Components

3.1.1.1 General Mechanical Components. Typically all mechanical components should be subjected to a load-run test (see para. 3.2.2) as a PMT, where the appropriate operating parameters should be validated against vendor-recommended limits as well as historical operating data. Leak checks and vibrational checks (see para. 5.2) should be performed as appropriate.

3.1.1.2 Major Engine Components. These components have a direct effect on horsepower output (e.g., pistons, connecting rods, crankshafts, cylinder assemblies, heads, cams, injectors, turbochargers, gear trains). As horsepower impacts both transient and steady-state loading, a slow-start (see para. 3.2.1) or a fast-start test (see para. 3.2.3) as appropriate, a load-run test (see para. 3.2.2), as well as a margin test (at 110% of continuous rating) should be performed to ensure rated horsepower is obtained. Additionally, engine analysis (see para. 5.1) should be performed. These tests should be performed in addition to any manufacturer-recommended break-in runs.

3.1.1.3 Active Starting System Components. These components change state in order to start the diesel generator (e.g., solenoid valves, pressure-regulating valves, air control valves, check valves, starting motor). A fast-start test (see para. 3.2.3) should be performed to ensure that the diesel generator reaches rated frequency and voltage as designed. Test times should be compared to historical data.

3.1.1.4 Engine Governor or Electronic Fuel Injection Control. The governor or electronic fuel injection control affect both transient and steady-state control of engine load and speed. As a minimum, a slow-start (see para. 3.2.1) or a fast-start test (see para. 3.2.3) as appropriate, a load-run test (see para. 3.2.2), a margin test (at 110% of continuous rating), and a transient response test designed to demonstrate the new component's dynamic response characteristics should be performed. Test data should be compared to historical data, and new baselines established as applicable. Consideration should be given to performing a load rejection test (see para. 3.2.8), an SIAS and LOOP test (see para. 3.2.6), and/or a largest-load rejection test (see para. 3.2.7) as conditions permit or where small test acceptance margins exist. A leak check should be performed on governor actuators and associated components as applicable.

3.1.1.5 Voltage Regulator. The voltage regulator affects both transient and steady-state control of the generator output. As a minimum, a fast-start test (see para. 3.2.3), a load-run test (see para. 3.2.2), a margin test (at 110% of continuous rating), and a transient response test designed to demonstrate the new component's dynamic response characteristics should be performed. Test data should be compared to historical data, and new baselines established as applicable. Consideration should be given to performing a load rejection test (see para. 3.2.8), an SIAS and LOOP test (see para. 3.2.6), and/or a largest load rejection test (see para. 3.2.7) as conditions permit or where small test acceptance margins exist.

3.1.1.6 Generator. The generator has a direct effect on both transient and steady-state loads on the diesel generator. As a minimum, a fast-start test (see para. 3.2.3), a load-run test (see para. 3.2.2), a margin test (at 110% of continuous rating), and a transient response test designed to demonstrate the new component's dynamic response characteristics should be performed. Test data should be compared to historical data, and new baselines established as applicable. Consideration should be given to performing a load-rejection test (see para. 3.2.8), an SIAS and LOOP test (see para. 3.2.6), and/or a largest-load rejection test (see para. 3.2.7) as conditions permit or where small test acceptance margins exist.

3.1.1.7 Other Diesel Generator Controls. Other controls may include various relays and protective trips. The specific function of the control must be considered in determining the appropriate PMT. Controls associated with starting the diesel generator should be subjected to a slow-start (see para. 3.2.1) or a fast-start test (see para. 3.2.3) as appropriate. Controls associated with the governor or voltage regulator should be subjected to the appropriate loading or transient tests based on their function. An overspeed trip test should be performed when components associated with the overspeed trip are disturbed or replaced. Testing of protective trips should take into account the function of the trip during design conditions.

3.2 Periodic Tests

Performance of periodic diesel generator tests and monitoring operating parameters provide the owner/operator with an immediate determination of the engine performance and material condition. The owner/operator shall perform periodic tests in accordance with plant procedures. The periodic testing frequencies identified in this Part are recommendations. They are identified as a matter of convenience for the monitoring of operating parameters and to coincide with plant testing programs.

Table 1
Periodic Tests

Ref.	Tests	Periodicity									
		Monthly		Quarterly		6 Months		18–24 Months		10 Years	
		Cl. 1E	Non-1E	Cl. 1E	Non-1E	Cl. 1E	Non-1E	Cl. 1E	Non-1E	Cl. 1E	Non-1E
3.2.1	Slow start	X	...	...	X	...	...	...	...	...	...
3.2.2	Load run	X	...	...	X	...	...	...	...	...	...
3.2.3	Fast start	...	...	...	...	X	NA	...	...	...	...
3.2.4	LOOP	...	...	...	...	...	...	X	As req.	...	...
3.2.5	SIAS	...	...	...	...	...	...	X	NA	...	...
3.2.6	SIAS and LOOP	...	...	...	...	...	...	X	NA	...	...
3.2.7	Largest-load rejection	...	...	...	...	...	...	X	X	...	...
3.2.8	Design-load rejection	...	...	...	...	...	...	X	X	...	...
3.2.9	Endurance and load margin	...	...	...	...	...	...	X	X	...	...
3.2.10	Hot restart	...	...	...	...	...	...	X	X	...	...
3.2.11	Synchronizing	...	...	...	...	...	...	X	X	...	...
3.2.12	Protective trip bypass	...	...	...	...	...	...	X	As req.	...	...
3.2.13	Test mode override	...	...	...	...	...	...	X	As req.	...	...
3.2.14	Independence	...	...	...	...	...	...	...	...	X	As req.

Table 1 states the periodicity of when the tests in paras. 3.2.1 through 3.2.14 should be performed. Class 1E is safety-related systems and Non-1E is non-safety-related.

3.2.1 Slow-Start Test

Class	Test Frequency
Safety-related system	Monthly
Non-safety-related system	Quarterly

This test demonstrates proper startup from standby conditions and verifies that the required design voltage and frequency are attained. The diesel generator should reach rated speed on a prescribed schedule to minimize stress and wear. This is a functional test to verify proper operation. Reducing the number of starts for a non-safety-related system will reduce engine wear. However, extending test frequency beyond quarterly will further reduce oil retention on component wear surfaces and increase oxidation on electrical contact surfaces.

3.2.2 Load-Run Test

Class	Test Frequency
Safety-related system	Monthly
Non-safety-related system	Quarterly

This test demonstrates 90% to 100% of the continuous rating of the diesel generator for an interval of not less than 1 hr and until attainment of temperature equilibrium. This test may be accomplished by synchronizing the

generator with offsite power. The loading and unloading of a diesel generator during this test should be gradual and based on a prescribed schedule that is selected to minimize stress and wear on the diesel generator. This is a functional test of engine and system components to assure reliability. Testing may be performed at a nominal power factor suitable to the grid condition at the time of the test.

3.2.3 Fast-Start Test

Class	Test Frequency
Safety-related system	Every 6 months
Non-safety-related system	Not applicable (NA)

This test demonstrates proper startup from standby conditions and verifies that the required design voltage and frequency are attained. The acceptance criteria for frequency and voltage should be equal to or greater than the minimum required voltage and frequency within the specified time allowance for the safety-related loads. Consider defining normal standby using a time-at-rest requirement instead of temperature to preclude preconditioning debates.

3.2.4 Loss-of-Offsite Power (LOOP) Test

Class	Test Frequency
Safety-related system	Every refueling cycle
Non-safety-related system	Every refueling cycle or every 24 months, if part of design feature

Table continued

(a) *Safety-Related System*. This test simulates the safety-related diesel generator response to a LOOP to demonstrate that

(1) the emergency buses are de-energized and the loads are shed from the emergency buses

(2) the diesel generator starts on the auto-start signal from its standby conditions; attains the required voltage and frequency, and energizes permanently connected loads within acceptable limits and time; energizes all auto-connected shutdown loads through the load sequencer; and operates for greater than or equal to 5 min

If the required safety loads are not available, one or more equivalent loads may be used.

(b) *Non-Safety-Related System*. If the plant design incorporates LOOP response for the non-safety-related diesels, this test simulates the non-safety-related diesel response to a LOOP to demonstrate that

(1) the buses are de-energized and the loads are shed from the buses

(2) the diesel generator starts on the auto-start signal from its standby conditions; attains the required voltage and frequency, and energizes permanently connected loads within acceptable limits and time; energizes all auto-connected loads and sequenced loads through the load sequencer, if required; and operates for greater than or equal to 5 min

If the required loads are not available, one or more equivalent loads may be used.

3.2.5 Safety Injection Actuation Signal (SIAS) Test

Class	Test Frequency
Safety-related system	Every refueling cycle
Non-safety-related system	Not applicable (NA)

This test demonstrates that on an SIAS, the diesel generator starts on the auto-start signal from its standby conditions, attains the frequency and voltage within acceptable limits and time, and operates for a minimum of 5 min.

3.2.6 SIAS and LOOP Test

Class	Test Frequency
Safety-related system	Every refueling cycle
Non-safety-related system	Not applicable (NA)

This test demonstrates that the diesel generator can satisfactorily respond to a LOOP in conjunction with SIAS by verifying that the unit starts on the auto-start signal from its standby conditions, attains the frequency and voltage within acceptable limits and time, energizes the auto-connected shutdown loads through the load sequencer within the acceptable limits of pump start time, and operates for a minimum of 5 min.

3.2.7 Largest-Load Rejection Test

Class	Test Frequency
Safety-related system	Every refueling cycle
Non-safety-related system	Every refueling cycle or every 24 months

This test demonstrates the diesel generator's capability to reject a load equal to loss of the largest single load while operating at its design load power factor, and verifies that the frequency and voltage requirements are met and the unit will not trip on overspeed. This test challenges the ability of the engine governor (or electronic fuel injection control) and generator voltage regulator to maintain the remaining connected loads. For a non-safety-related system, the test could be performed at unity power factor to reduce stresses on the generator system.

3.2.8 Design-Load Rejection Test

Class	Test Frequency
Safety-related system	Every refueling cycle
Non-safety-related system	Every refueling cycle or every 24 months

This test demonstrates the diesel generator's capability to reject a load, equal to 90% to 100% of the continuous rating and equal to or greater than 100% of the design load, while operating at its design-load power factor, and verifies that the voltage requirements are met and that the unit will not trip on overspeed. This test challenges the ability of the engine governor (or electronic fuel injection control) to recover to rated speed without actuating the overspeed trip. For a non-safety-related system, the test could be performed at unity power factor to reduce stresses on the generator system.

3.2.9 Endurance and Load Margin Test

Class	Test Frequency
Safety-related system	Every refueling cycle
Non-safety-related system	Every refueling cycle or every 24 months

This test demonstrates the capability of the diesel generator at continuous rating and worst-case power factor for an interval of not less than 24 hr. Of this period, 2 hr or more should be at a load equal to 105% to 110% of the diesel generator's continuous rating, and 22 hr or the remaining hours should be at a load equal to 90% to 100% of the generator's continuous rating. The test process should verify that frequency and voltage requirements are maintained. This test is to demonstrate the diesel generator's capability to carry load for an extended run. For a non-safety-related system, the test could be run at continuous rating of the diesel generator for no less than 8 hr at rated power factor. The 8-hr duration is consistent with IEEE 387-1995 (reaffirmed September 2007).

3.2.10 Hot Restart Test

Class	Test Frequency
Safety-related system	Every refueling cycle
Non-safety-related system	Every refueling cycle or every 24 months

This test demonstrates the hot restart functional capability at full load-temperature conditions (after the diesel generator has operated for 2 hr at continuous rating) by verifying that the diesel generator starts on a manual or auto-start signal, attains the required frequency and voltage within acceptable limits and time, and operates for longer than 5 min. This test may be performed following the endurance and load margin test described above. The intent is to demonstrate that the diesel generator is capable of restarting after a normally scheduled surveillance run, i.e., the diesel generator is “hot” rather than in the normal standby temperature range.

3.2.11 Synchronizing Test

Class	Test Frequency
Safety-related system	Every refueling cycle
Non-safety-related system	Every refueling cycle or every 24 months

The test demonstrates the ability to

- (a) synchronize the diesel generator unit with offsite power while the unit is connected to the emergency load
- (b) transfer this load to the offsite power
- (c) isolate the diesel generator unit
- (d) restore the diesel generator unit to standby status

3.2.12 Protective Trip Bypass Test

Class	Test Frequency
Safety-related system	Every refueling cycle
Non-safety-related system	Every refueling cycle or every 24 months, if part of design feature

This test demonstrates that automatic diesel generator unit trips are bypassed as designed. Typically, engine overspeed, generator differential current trip, and those trips retained with coincident logic are not bypassed. This test should also verify that the critical protective trips that are not automatically bypassed perform their intended function.

3.2.13 Test Mode Override Test

Class	Test Frequency
Safety-related system	Every refueling cycle
Non-safety-related system	Every refueling cycle or every 24 months, if part of design feature

This test demonstrates that with the diesel generator operating in the test mode while connected to its bus, a simulated safety injection signal overrides the test mode by

- (a) returning the diesel generator to standby operations
- (b) automatically realigning the emergency loads to offsite power

3.2.14 Independence Test

Class	Test Frequency
Safety-related system	Every 10 yr
Non-safety-related system	Every 10 yr if required

This test demonstrates that by starting and running (unloaded) redundant units simultaneously, potential common failure modes that may be undetected in single diesel generator unit tests do not occur.

3.3 Other Testing Guidelines

Subsequent to placing a diesel generator into service at a nuclear power plant, the system shall be tested periodically to demonstrate that 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 generator protective trips and alarms should be in operation during the testing.
- (d) Periodic testing of the diesel generator 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.

4 INSERVICE MONITORING OF COMPONENT OPERATING AND STANDBY CONDITIONS

The diesel generator and supporting components are operated periodically during normal engine operational surveillance testing. System performance data should 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 generator can be identified and corrected. Given below are the diesel generator subsystem components and the parameters to be monitored as applicable to station requirement/design for the standby diesel generator system.

Engine operating data should be recorded with the diesel engine running at rated load and stabilized at normal operating temperatures. In many cases, a subsystem and/or component's performance can be monitored by more than one parameter. When a desired parameter is not available, another accessible parameter may be available to satisfy the monitoring requirements. Note that the operating range of each parameter may vary between engine runs, depending on the operating condition, i.e., outside temperature and barometric pressure. During an endurance surveillance run, operating data should be recorded at least hourly to provide the opportunity to detect emerging malfunctions. Operating data recorded during engine surveillance runs should be trended and evaluated, to monitor equipment health and to identify declining performance or material condition.

4.1 Engine

(a) Standby Condition-Monitoring Parameters

- (1) engine mounting bolts tightness
- (2) skid mounting bolts tightness

(b) Operational Performance Monitoring Parameters

- (1) engine vibration
- (2) engine cylinder pressure
- (3) engine RPM

4.2 Lubrication Subsystem

(a) Standby Condition-Monitoring Parameters

(1) system visual inspection for external oil leaks/degradation

- (2) engine and turbo lube oil sump levels
- (3) lube oil analysis
- (4) engine circulating lube oil pressure
- (5) engine circulating lube oil temperature

(b) Operational Performance Monitoring Parameters

(1) system visual inspection for external oil leaks/degradation

- (2) engine lube oil in/out pressures
- (3) turbocharger lube oil in/out pressures
- (4) lube oil strainer in/out differential pressure
- (5) lube oil filter in/out differential pressure
- (6) engine lube oil in/out temperatures
- (7) lube oil cooler in/out temperatures

4.3 Jacket Water and Intercooler Subsystem

(a) Standby Condition-Monitoring Parameters

(1) system visual inspection for external cooling water leaks/degradation

- (2) radiator/fan visual inspection for degradation
- (3) jacket water keep-warm temperature
- (4) jacket water keep-warm pressure
- (5) coolant level
- (6) cooling water chemical analysis

(b) Operational Performance Monitoring Parameters

(1) system visual inspection for external leaks/degradation

- (2) service water flow rate
- (3) service water temperature
- (4) jacket water temperature
- (5) engine power output
- (6) intake manifold temperature
- (7) radiator water/air in/out temperatures
- (8) radiator fan vibration
- (9) jacket water pump pressure
- (10) intercooler pump pressure

4.4 Starting Subsystem

(a) Standby Condition-Monitoring Parameters

(1) system visual inspection for external air leaks/degradation

- (2) air compressor oil level
- (3) air receiver blowdown
- (4) air receiver pressure
- (5) air start solenoid valve lubricator operation and oil level
- (6) battery/charging systems alarms and local indications

(b) Operational Performance Monitoring Parameters

(1) system visual inspection for external air leaks/degradation

- (2) fast start test time
- (3) compressor run times
- (4) compressed air usage
- (5) dryer operation
- (6) dew point temperature of compressor/dried air
- (7) electrical current consumption

4.5 Combustion Air Intake Subsystem

(a) Standby Condition-Monitoring Parameters

(1) system visual inspection for external leaks/degradation

(2) visual inspection of bird screens and louvers for obstructions

(b) Operational Performance Monitoring Parameters

- (1) air filter in/out differential pressure
- (2) engine inlet air temperature
- (3) intercooler in/out differential pressure
- (4) mechanical blower outlet pressure
- (5) scavenging pump outlet pressure

- (6) supercharger outlet pressure
- (7) turbocharger outlet pressure

4.6 Exhaust Subsystem

- (a) *Standby Condition-Monitoring Parameters*
 - (1) system visual inspection for degradation
 - (2) visual inspection of wall/roof penetrations for possible fire hazard
- (b) *Operational Performance Monitoring Parameters*
 - (1) exhaust back pressure
 - (2) cylinder exhaust temperatures
 - (3) system visual inspection for degradation

4.7 Fuel Oil Subsystem

- (a) *Standby Condition-Monitoring Parameters*
 - (1) system visual inspection for external fuel oil leaks/degradation
 - (2) owner-approved acceptance criteria for fuel oil quality/condition
 - (3) open low-point drains and inspect for water
 - (4) visual inspection for blockage of tank vents
- (b) *Operational Performance Monitoring Parameters*
 - (1) system visual inspection for external fuel oil leaks/degradation
 - (2) fuel oil transfer pump flow rate
 - (3) fuel oil transfer pump discharge pressure
 - (4) on-engine fuel oil pump discharge pressure
 - (5) strainer/filter in/out differential pressure

4.8 Crankcase Ventilation Subsystem

- (a) *Standby Condition-Monitoring Parameters*
 - (1) system visual inspection for external leaks/degradation
- (b) *Operational Performance Monitoring Parameters*
 - (1) system visual inspection for external leaks/degradation
 - (2) crankcase pressure

4.9 Governor and Control Subsystem

- (a) *Standby Condition-Monitoring Parameters*
 - (1) governor oil level
- (b) *Operational Performance Monitoring Parameters*
 - (1) engine speed response during start and load

4.10 Generator Subsystem

- (a) *Standby Condition-Monitoring Parameters*
 - (1) visually check air cooling ports
 - (2) strip heater operation
- (b) *Operational Performance Monitoring Parameters*
 - (1) generator bearing vibration
 - (2) stator temperature

4.11 Ventilation and Cooling Subsystem

- (a) *Standby Condition-Monitoring Parameters*
 - (1) visual inspection of inlet louvers and screens for blockage
 - (2) diesel room ambient air temperature
- (b) *Operational Performance Monitoring Parameters*
 - (1) diesel room ambient air temperature
 - (2) fan vibration

4.12 Exciter and Voltage Regulator Subsystem

- (a) *Standby Condition-Monitoring Parameters*
 - (1) none
- (b) *Operational Performance Monitoring Parameters*
 - (1) voltage response during start and load

4.13 Control and Protection Subsystem

- (a) *Standby Condition-Monitoring Parameters*
 - (1) overspeed trip mechanism position (where applicable)
- (b) *Operational Performance Monitoring Parameters*
 - (1) relay responses

4.14 Diesel Generator Output Breaker

- (a) *Standby Condition-Monitoring Parameters*
 - (1) breaker flag
- (b) *Operational Performance Monitoring Parameters*
 - (1) breaker operation

5 OTHER CONDITION-MONITORING METHODS/ GUIDELINES

5.1 Diesel Engine Analysis

Class	Test Frequency
Safety-related system	Perform every 24 months as a part of a condition-based maintenance (CBM) program and after completion of major engine maintenance activities to reestablish baseline operating data
Non-safety-related system	Same as safety-related system

(a) *General.* Diesel engine analysis is an effective tool in support of an inservice testing and/or a CBM program because

- (1) it provides the technical basis for developing a performance-based maintenance program
- (2) it detects certain degraded engine material conditions 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 compression and firing pressure),

vibration as recorded by accelerometers, and unusual sounds as recorded by ultrasonic transducers. 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.

NOTE: Some smaller non-safety-related diesel generators may not have the capability to collect and record engine cylinder firing and compression pressures if they do not have Kiene valve fittings in the cylinder heads.

(b) *Benefits.* Benefits realized from diesel engine analysis, especially as part of a CBM program, include the following:

(1) *Reduced Maintenance.* Users of diesel engine analysis experience reductions in maintenance costs by 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 identifying potential maintenance-induced failures.

(3) *Increased Availability.* Reduced time required for maintenance activities permits the plant to increase diesel engine availability.

(4) *Problem Identification.* Issues identified in the past using engine analysis include bent connecting rod, degraded injector/injection pumps, cracked intake and exhaust valves, collapsed valve lifter, and degraded engine timing. These types of problems, when identified early and corrected, avoid major engine failures.

5.2 Vibration Analysis

Class	Test Frequency
Safety-related system	Perform quarterly
Non-safety-related system	Perform quarterly

Machinery vibration is the response of the component structural mass and stiffness combinations when subjected to an excitation. A diesel engine produces harmonic excitations as a function of combustion forces, torque reactions, number of engine cylinders, and cylinder firing order. Other factors influencing vibration include engine balance, generator balance, injector timing, coupling alignment, condition of bearings, and operating conditions.

Vibratory motion can be described in terms of displacement, velocity, or acceleration; all three are used in the diagnoses of vibration problems. Vibration analyses on engine, generator, generator bearing, pumps and motors (circulating water pumps, circulating lube oil pumps, turbo soakback oil pumps, fuel pumps, etc.) should be performed while operating at steady state and within normal operating temperature ranges. Changes in vibration level can occur as a result of changes in operating parameters, e.g., temperature, pressure, and engine load.

In general, machinery vibration is complex and consists of many frequencies. To make use of all the information embedded in the vibration signal, frequency analyses should be performed to determine the dominant frequencies and amplitudes. Vibration amplitudes that are abnormally high are often an indication of an existing mechanical problem that needs identification and correction. The composite amplitude and the amplitudes at discrete frequencies at each measurement location should be trended for condition monitoring.

Frequency spectra obtained from measurements made on the engine and generator structure will reveal low-frequency components at shaft speed originating from unbalances, misalignments, bent shaft, etc. Frequency components originating from the gear mesh in the gearbox are generally referred to as medium-frequency components. They correspond to rotational speed times the number of teeth on the gear (gear mesh frequency). In this frequency range, indication of wear and incipient faults in a gearbox, eccentricity, uneven gear wheels, and misaligned gears will be found. As the gearbox wears, the amplitudes of the gear mesh frequency and its harmonics will increase. Frequency components originating from rolling element bearing incipient faults are generally in a higher frequency range. A crack on the inner race or the outer race will create small impulses every time a roller element passes over it. These impulses will excite the bearing housing at its natural frequency.

In general, the engine-generator structural and drive-line natural frequencies, engine-generator forcing frequencies, and gear meshing frequencies are less than 500 Hz. Engine-generator vibration signature up to 500 Hz should be measured and trended to monitor the physical condition of the engine-generator system. In the case of generator roller bearings, vibration signature up to 5,000 Hz or 10,000 Hz is necessary to track the bearing condition.

The owner/operator should refer to the engine manufacturer recommended measurement locations and allowable vibration guidelines. Measurements should be recorded at rated speed during full-load operation. The composite vibratory amplitude and the amplitudes of significant frequency components should be trended and compared to other similar installations.

5.3 Lube Oil Analysis

Class	Test Frequency
Safety-related system	Perform quarterly
Non-safety-related system	Perform quarterly

Engine lubricating oil serves to reduce friction and wear, cool engine parts, and protect against corrosion. Periodic lube oil analysis is a valuable tool for evaluating the condition of the oil and assessing material condition of the engine. Traces of wear metals in the lube oil can be used to identify accelerated component wear. Lube oil analysis results should be trended for condition monitoring.

Lube oil degradation includes oxidation, nitration, permanent viscosity change, and additive depletion. Oil oxidation is often caused by excessive operating temperature; it increases oil viscosity and creates acids that corrode metals and cause wear. Nitration is often a result of improper combustion; it may result in grease-like deposits. Permanent viscosity changes will affect the shear stability of the oil. Oil additives, i.e., dispersants, antioxidants, rust/corrosion inhibitors, and film-strength agents, are consumed as oil ages in service. (Dispersants are needed to suspend deposit-forming contaminants in the oil until they can be removed by the oil filter.) The total base number (TBN) is a key parameter (though not the only factor) for determining whether the oil should be replaced. TBN measures the total amount of basic (alkaline) materials present in the lube oil. Decreases in TBN may indicate reduced acid-neutralizing capacity or depleted additive package. Total acid number (TAN) measures the total amount of acid product present in the lube oil. An increase in TAN indicates oil oxidation or contamination with an acidic product.

Lube oil contaminants include combustion products, fuel, dirt, wear metals, water, and coolant additives. Combustion products (soot, sulfur, etc.) are caused by improper combustion or defective injectors; they will increase oil viscosity, form deposits, and corrode engine parts. Fuel dilution will reduce oil viscosity and cause piston/cylinder scuffing and bearing failures. Dirt and dust are caused by inadequate air filtration and can lead to vital engine part damage. Water can result from coolant leaks or low operating temperature; it will cause rust and corrosion. Water will form sludge by combining with other contaminants.

The lube oil sampling procedure should specify the requirement to collect a well-mixed oil sample, e.g., during engine operation (flowing sample), at the end of or shortly after a surveillance run. The owner/operator should consult the engine manufacturer to determine acceptable lube oil parameters for the specific diesel engine being evaluated.

5.4 Cooling Water Analysis

Class	Test Frequency
Safety-related system	Perform quarterly
Non-safety-related system	Perform quarterly

Engine jacket cooling water is circulated through the engine cylinder liner and head to remove the heat generated during the combustion process. Since untreated water accelerates corrosion of engine parts, a corrosion inhibitor must be added to the jacket-cooling water. While in service, the chemicals in the treated water will deplete slowly as a function of the diesel engine's duty cycle. In order to monitor the effectiveness of the treated water in preventing corrosion, jacket cooling water analysis should be performed regularly and the analysis results should be trended.

5.5 Thermography

Class	Test Frequency
Safety-related system	Perform every 24 months
Non-safety-related system	Perform every 24 months

The use of thermography has been a major addition to predictive maintenance inspection programs for diesel generators and associated electrical components. Thermographic inspection refers to the nondestructive examination of components through the imaging of the thermal patterns at the object's surface through the use of an infrared (IR) detector. The typical approach to thermographic inspection is through the use of a passive IR recording camera, in which the features of interest are naturally at a higher or lower temperature than the background. A thermal imaging camera is a reliable, safe, noncontact, nonintrusive instrument that is able to scan and show the temperature distribution of entire surfaces of machinery and electrical equipment quickly and accurately.

Thermography can reveal and measure heat generation in machines and installations. It shows overheated components, and detects and can prevent breakdowns. The first principle of IR sensing is "many components heat up before they fail." Second, all objects emit thermal radiation in the IR spectrum that is not seen by the human eye. Third, IR cameras convert that radiation to visual images that are calibrated to a temperature scale. This noncontact temperature data can be displayed on a monitor in real time and can be sent to a digital storage device for analysis. Measurement accuracy is typically $\pm 2^{\circ}\text{C}$. IR cameras do not require lighting to produce their images, and can see hot spots well before excessive heat or loss of insulation leads to failure. For example, transformer fluid leaks or internal insulation breakdown cause overheating that leads to failures. Impending electrical equipment failures due to overheating and loose

contacts can be identified and corrected. Exhaust system leaks, and overheated hydraulic system components and fuel injection pumps, can be identified for corrective action.

A thermographic report, consisting of a visual and an IR photo of the scanned object, a temperature curve, basic thermographic data, and a technical summary, is compiled and used for later comparison on a periodic inspection schedule. As overheated conditions are identified, the plant maintenance team can take corrective action to resolve the problem, thereby preventing costly failures.

6 ALARM AND SHUTDOWN DURING TESTS

During the testing of the diesel engine and its generator, 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 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 generator alarm and shutdown limits within its operating procedures, with consideration of manufacturer's recommendations.

7 DIESEL GENERATOR OPERATING DATA AND RECORDS

Diesel generators 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

Nonmandatory Appendices A and B of this Part provide sample tables for data collections.

Section 4 of this Part lists the data that should be considered for collection during periodic inservice testing. The owner/operator has the responsibility for the development of plant-specific data sheets. The owner/operator should consult the engine manufacturer for the determination of critical operating parameters for the specific diesel generator 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 Nonmandatory Appendix C of this Part 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 generator'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/generator 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. Such records will highlight repeated component failures that degrade diesel generator performance and material condition, and focus on the need for corrective actions to prevent recurrence.

Part 16, Nonmandatory Appendix A

Post-Major Maintenance Test Data

See Figure A-1 below for test data form.

Figure 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 (IN)	°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 ₂ O			
22	Air Intake Pressure	in. Hg			
23	Crankcase Vacuum	in. H ₂ O			
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 Figure B-1 below for test data form.

Figure 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	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 ₂ O		
23	Pre-Turbo Air Intake Pressure	in. H ₂ O		
24	Air Intake Manifold (Receiver) Pressure	in. Hg		
25	Air Intake Manifold (Receiver) Temperature	°F (°C)		
26	Crankcase Vacuum	in. H ₂ O		
27	No. 1 Injection Pump Rack Reading	...		
28	Cylinder Exhaust Temperature	°F (°C)		
29	Cylinder No. 1/No. 2	°F (°C)		
30	Cylinder No. 3/No. <i>n</i> [Note (1)]	°F (°C)		
31	Lube Oil Makeup	gal		
32	Fuel Oil Consumption	gph		

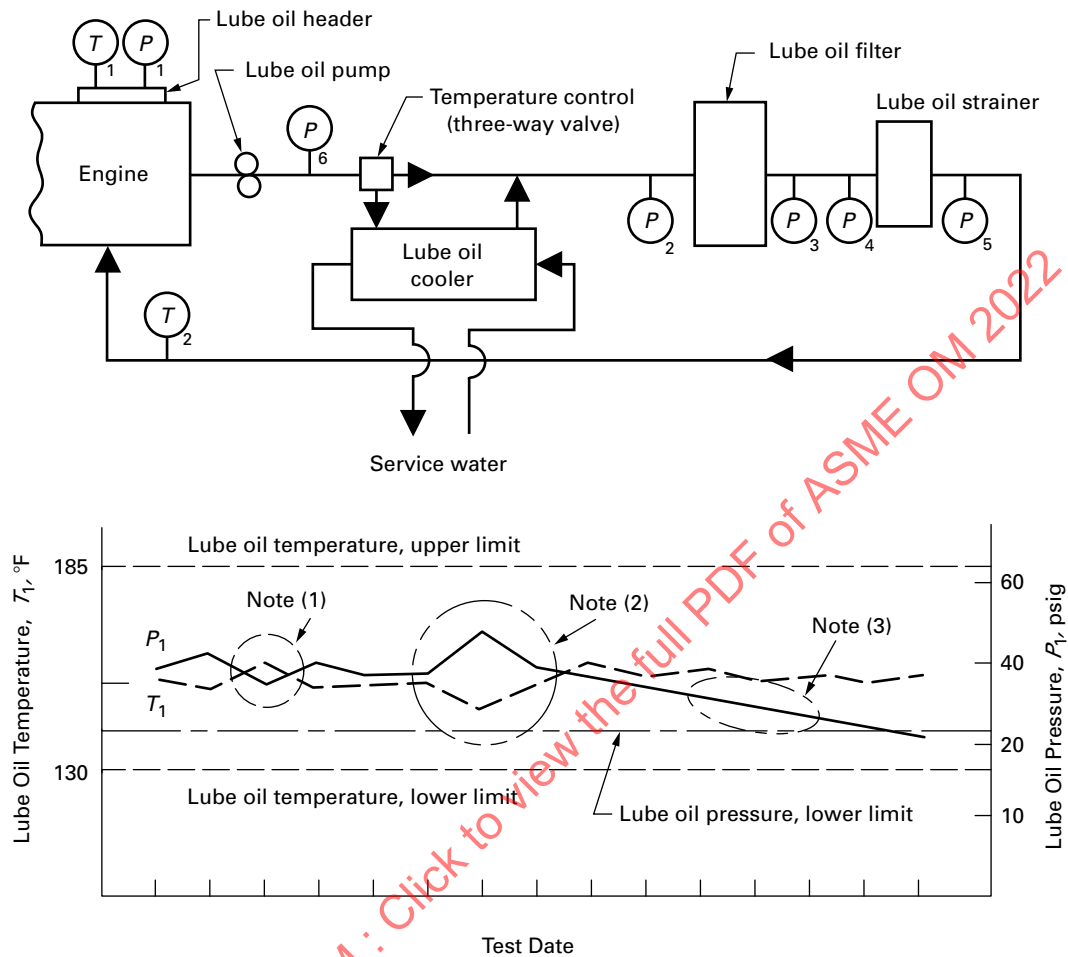
NOTE: (1) *n* represents the total number of cylinders.

Part 16, Nonmandatory Appendix C Data Trending Examples

See Figures C-1 through C-5 on the following pages for data trending examples.

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Figure C-1
Typical Lube Oil System

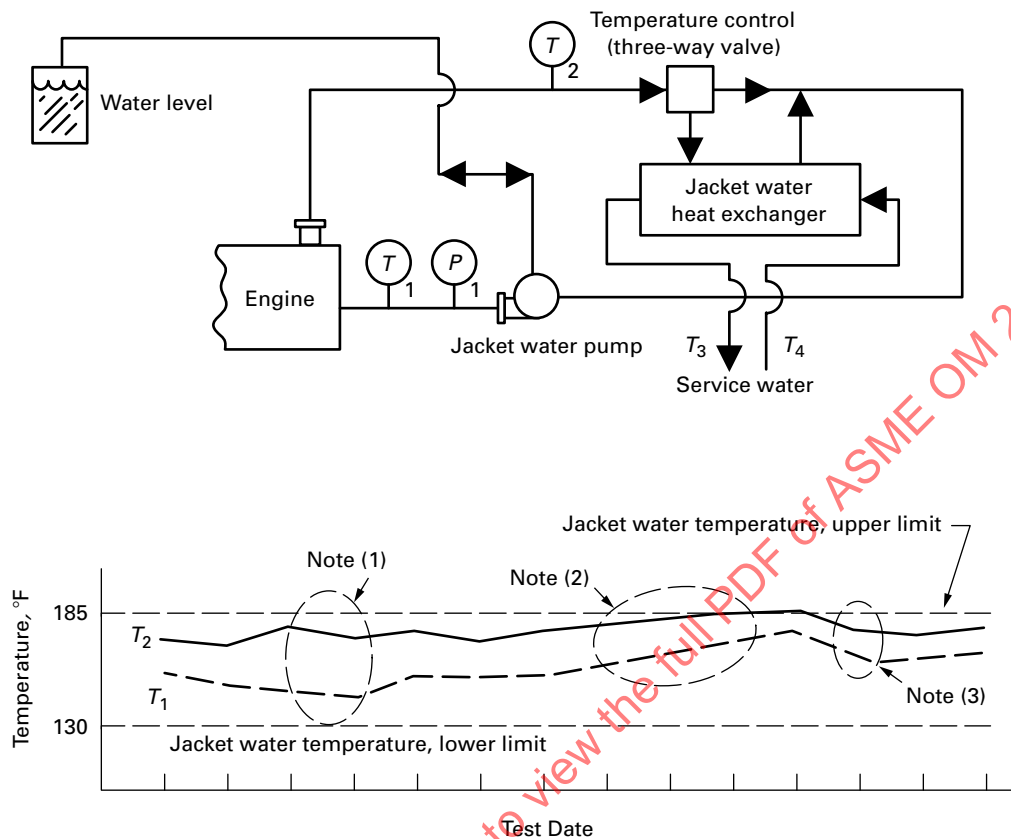


Trend Plotting — Lube Oil Temperature, T_1 , and Lube Oil Pressure, P_1

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

Figure C-2
Typical Jacket Water System

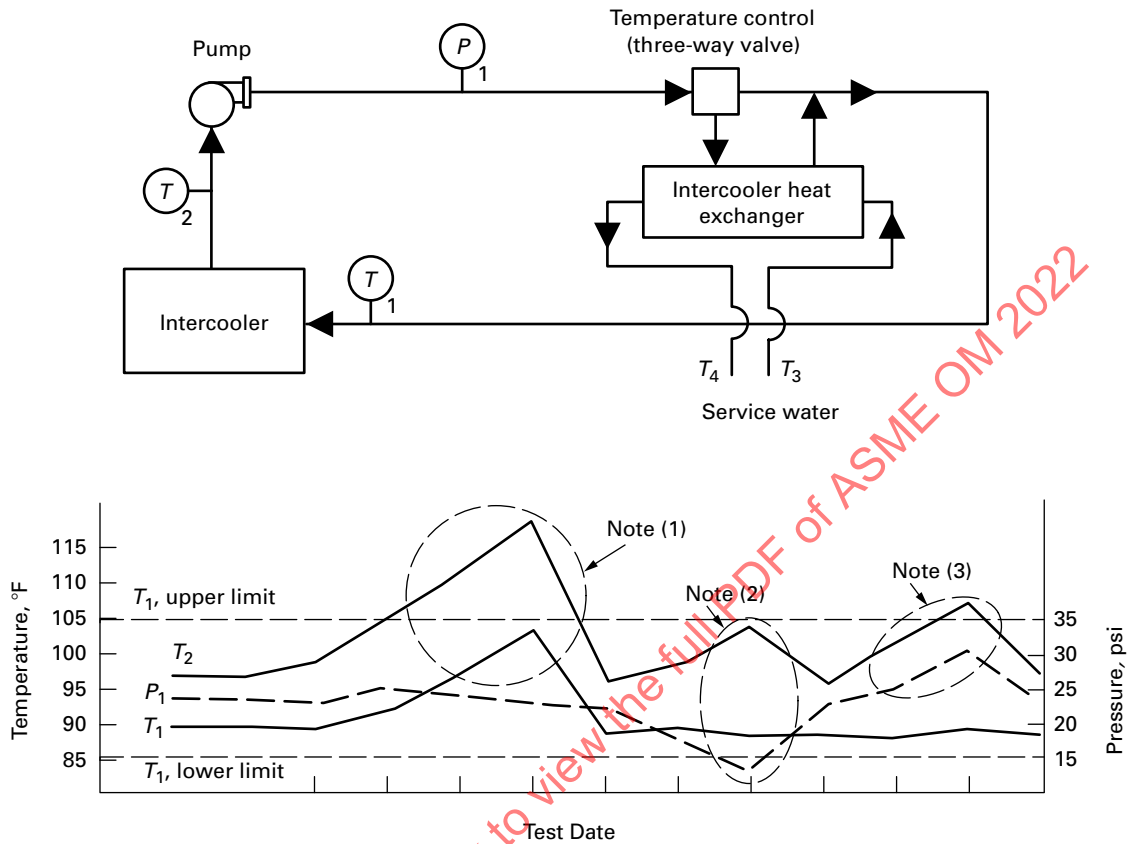


Trend Plotting — Jacket Water Temperature to Engine, T_1 , and From Engine, T_2

NOTES:

- (1) High ΔT across the engine. Possible causes, with $T_4 - T_3 = \text{constant}$, 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 are
 - (a) heat exchanger fouling
 - (b) faulty three-way temperature valve
 - (c) seawater system restricted
 - (d) service water inlet temperature too high
- (3) Normal operation conditions

Figure C-3
Intercooler Water System

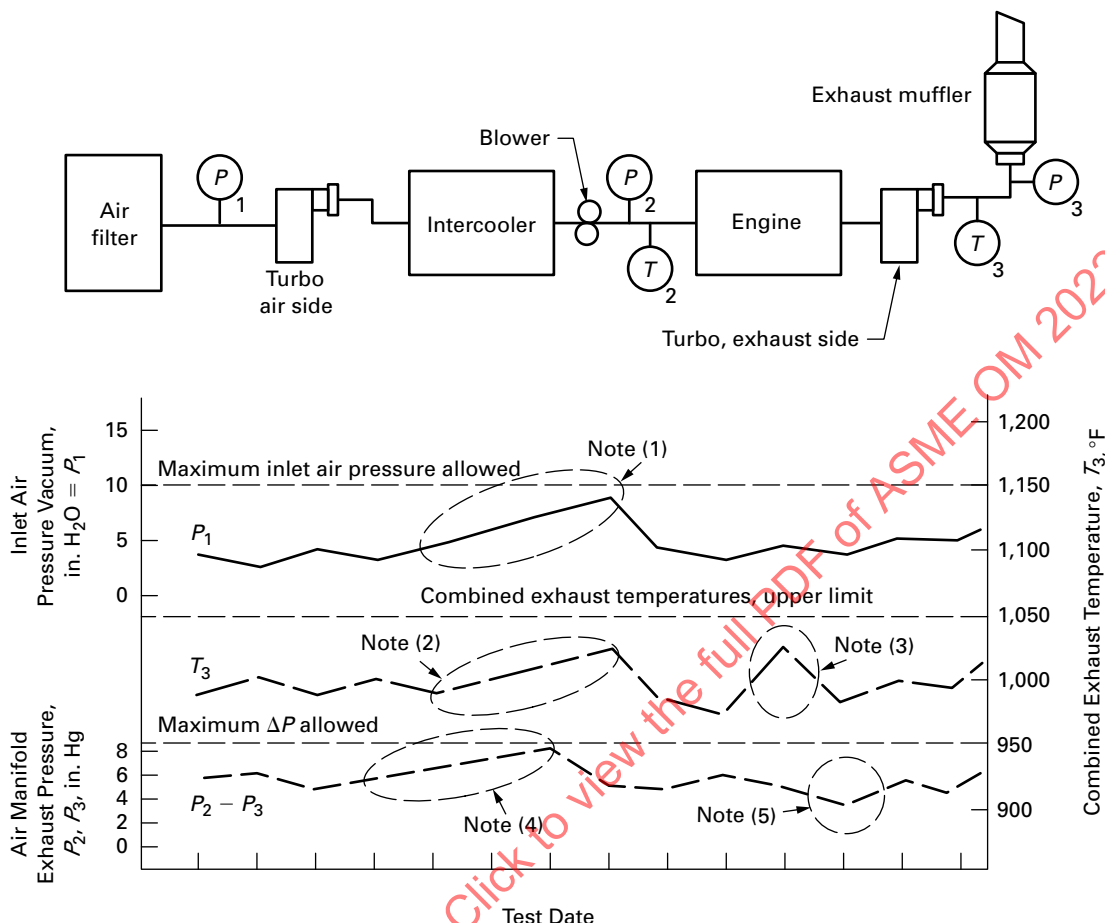


Trend Plotting — Air Cooler Water Temperature to T_1 and From T_2 Cooler Pump Pressure P_1

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.

Figure C-4
Typical Air/Exhaust System



Trend Plotting — Air/Exhaust System

Inlet Air Pressure (Vacuum) — P_1 = _____

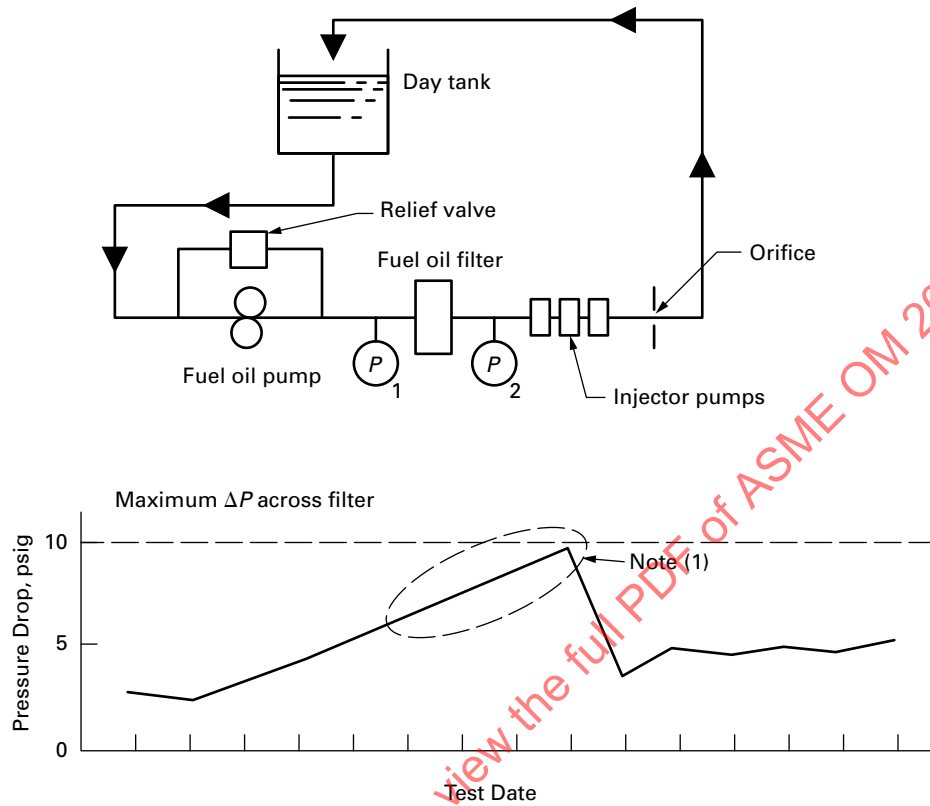
Air Manifold/Exhaust Back Pressure = $P_2 - P_3$ = _____

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 are
 - (a) faulty injection nozzle, nozzle streams foul
 - (b) injection timing change (retarded)
- (4) Increasing ΔP across engine. Possible causes are
 - (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.

Figure 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

Inservice Performance Testing of Heat Exchangers in Water-Cooled Reactor Nuclear 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.

(a) Standard for Power Plant Heat Exchangers; Publisher: Heat Exchange Institute, Inc. (HEI), 1300 Sumner Avenue, Cleveland, OH 44115

(b) 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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(b) 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

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(e) ASME Steam Tables, 5th edition (1983); Publisher: The American Society of Mechanical Engineers (ASME), Two Park Avenue, New York, NY 10016-5990

(f) Cameron Hydraulic Data, 16th edition (1984); Publisher: Ingersoll-Rand Company

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(h) 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), Two Park Avenue, New York, NY 10016-5990

(i) 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]

(j) 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), Two Park Avenue, New York, NY 10016-5990

(k) 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), Two Park Avenue, New York, NY 10016-5990

(l) 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), Two Park Avenue, New York, NY 10016-5990

(m) R. C. Lord, P. E. Minton, and R. P. Slusser, "Design of Heat Exchangers," *Chemical Engineering* (January 26, 1970): 96-116; Publisher: McGraw-Hill

(n) ASME PTC 19.1-1998, *Test Uncertainty*; Publisher: The American Society of Mechanical Engineers (ASME), Two Park Avenue, New York, NY 10016-5990

(o) H. W. Coleman and W. G. Steele, *Experimentation and Uncertainty Analysis for Engineers* (1989); Publisher: John Wiley & Sons

(p) A Mathematical Model for Assessing the Uncertainties of Instrumentation Measurements for Power and Flow of PWR Reactors, NUREG/CR-3659 (1985)

(q) H. S. Bean, ed., *Fluid Meters: Their Theory and Application* (1971)

(r) 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)

(s) HVAC Systems: Testing, Adjusting, and Balancing (1983); Publisher: Sheet Metal and Air Conditioning Contractors' National Association

(t) ASHRAE Handbook of Fundamentals (1989); Publisher: American Society of Heating, Refrigerating and Air-Conditioning Engineers, Inc. (ASHRAE), 1791 Tullie Circle, NE, Atlanta, GA 30329

(u) 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 Requirements¹

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.

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

¹ The requirements of para. 5.2 are applicable only during the period of time as specified in the definition of preservice test (see section 2).

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 Figure 1). If the testing or monitoring interval [I (test) in Figure 1] exceeds the maximum testing or monitoring interval, which assumes no corrective actions are performed [I (max.) in Figure 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 yr.

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 section 7), and errors, sensitivities, and uncertainties (see section 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 Figure 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 section 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 section 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 of this Part, para. C-1.

6.1.3 Inclusion Criteria. The functional test method shall be considered if

- (a) the acceptance criteria (see section 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 conditions²
- (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 motor heat loads to the room should be as they would be under the accident condition)²
- (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.

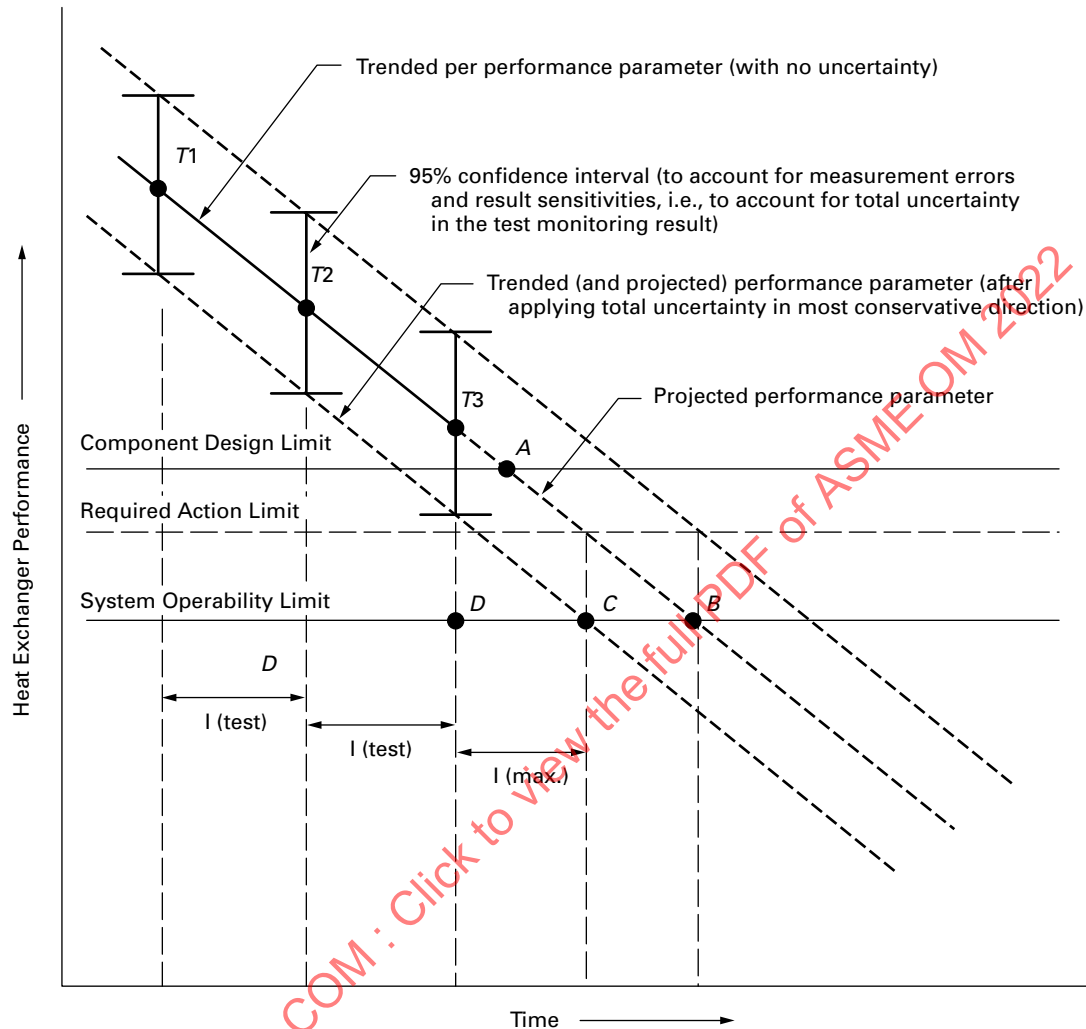
6.1.5 Required Parameter. The temperature of interest shall be measured to quantitatively evaluate the heat exchanger thermal performance using the functional test method.

NOTES:

- (1) The component of interest must be functioning within the design basis during testing to ensure this method accurately represents heat exchanger performance.
- (2) The temperature of interest can be affected by malfunctioning or degradation of system components other than the component of interest.

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.

Figure 1
Intervals, Limits, and Parameter Trending (Typical)

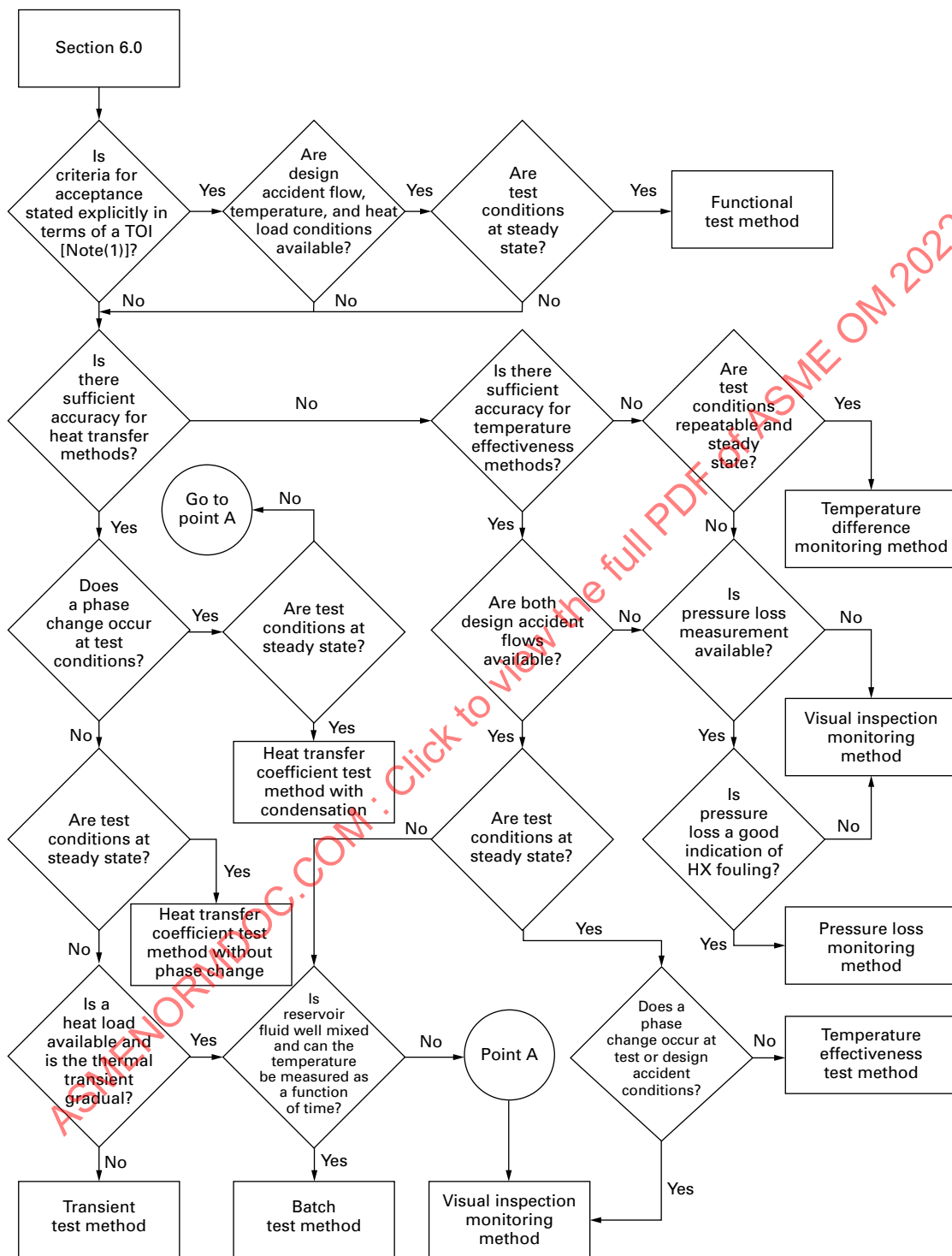


Legend:

- 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
- T1, T2, T3 = successive test or monitoring data points
- T3 = 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)
- T3 - D = current "absolute" operating margin (with no uncertainty)

GENERAL NOTE: Refer to sections 8 and 9 for discussion of trending, uncertainties, and action limits for test results.

Figure 2
Method Selection Chart



NOTE: (1) Temperature of interest.

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 of this Part, section 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 section 9) in terms of heat duty (Btu/hr)
- (b) sufficient accuracy (in accordance with section 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, e.g., shutdown cooling heat loads are only available during plant shutdown; see para. 5.4 and section 9)

6.2.5 Required Parameters. At least five of the following six parameters [(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 section 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 of this Part, section 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 section 9) in terms of heat duty (Btu/hr)
- (b) sufficient accuracy (in accordance with section 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, e.g., shutdown cooling heat loads are only available during plant shutdown; see para. 5.4 and section 9)

6.3.5 Required Parameters. At least seven of the following 10 parameters [(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 in (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 section 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 [(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 of this Part, section 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 section 9) in terms of heat duty (Btu/hr)

(b) sufficient accuracy (in accordance with section 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 inequalities (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, e.g., shutdown cooling heat loads are only available during plant shutdown; see para. 5.4 and section 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 $\pm 5\%$). 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 of this Part, section 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 section 8) is achievable at test conditions
- (b) both test flows can be manipulated to within $\pm 5\%$ 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 [(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 of this Part, section 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 section 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 in (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 of this Part, section 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 [(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 of this Part, section 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 of this Part, section 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 section 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 of this Part, section 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 [(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 of this Part, section 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 of this Part, section 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 Figure 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 of this Part, section 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 section 9 and Figure 1). Typical trendable parameters are presented in Nonmandatory Appendix C of this Part, section 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), 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

$$\left[\sum_i (M_i)(C_i) \right] [(\Delta T_{ave})/(\Delta \tau)] \ll Q \quad (1)$$

and the fluid flow on both the cooling fluid and process fluid sides has reached a steadiness defined as

$$[T_1 - T_2] [\Delta(WC)_{shell}] \ll Q \quad (2)$$

$$[t_1 - t_2] [\Delta(WC)_{tube}] \ll Q \quad (3)$$

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 inequalities (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 of this Part, 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 of this Part, para. C-11.1.2).

These inequalities must be continuously satisfied for a time period greater than τ_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 τ_1 , °F

t_1 = tube-side inlet temperature during time period τ_1 , °F

T_2 = shell-side outlet temperature during time period τ_1 , °F

t_2 = tube-side outlet temperature during time period τ_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 τ_1

$(WC)_{tube,min}$ = minimum value of the product of the tube-side mass flow rate and specific heat during time interval τ_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

τ_1 = 10 times the maximum value of either of the following in seconds:

$$\sum_i \left[M_i C_i / (WC)_{shell,min} \right]$$

$$\sum_i \left[M_i C_i / (WC)_{tube,min} \right]$$

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 Figure 1).

A standard statistical method for calculating the total uncertainty in the result is presented in Nonmandatory Appendix C of this Part, 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 of this Part, section 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 of this Part, section C-11.

The following considerations shall be addressed to minimize measurement errors:

(a) selection, calibration, and placement of instruments (see Nonmandatory Appendix C of this Part, section C-11)

(b) test and monitoring conditions (see section 7)

(c) instrument response times, transport delay times, and other factors (see Nonmandatory Appendices A and B of this Part)

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 of this Part, section 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 of this Part, section 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 of this Part, 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 section 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 of this Part, 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 section 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 of this Part 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 Figure 1 and section 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 Figure 1), while system operability may not be threatened, component

reliability could be threatened (refer to Nonmandatory Appendix B of this Part, section 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 section 8 and Figure 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 section 9, or whenever I (test) exceeds I (max.), as described in Figure 1. As part of this corrective action, the root cause of the failure should be determined (see Nonmandatory Appendix A of this Part).

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 selected³

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.

(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 section 5)

(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 sections 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

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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 section 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 of this Part, section 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 of this Part, section 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 intrinsic 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 3.2(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 of this Part, section 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 back-calculated 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 WATER HAMMER

In establishing system alignment and conditions for testing, precautions should be taken to prevent the occurrence of water hammers.

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 section 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, section 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 section 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 section 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, ft², based on inside surface area, including any fin area

A_o = total effective surface area, ft², 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-ft²-°F/Btu, based on outside surface area

r_i = inside fouling resistance, hr-ft²-°F/Btu, based on inside surface area

r_o = outside fouling resistance, hr-ft²-°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 back-calculation. 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 back-calculate 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 Figures B-1 through B-9 of the reference given in para. 3.1(b) or Figures 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)

$$F_d = 0.9588$$

$$\begin{aligned}
 P_d &= (t_{2,d} - t_{1,d}) / (T_{1,d} - t_{1,d}) \\
 &= (97.0 - 75) / (140.0 - 75) \\
 &= 0.3385 \\
 R_d &= (T_{1,d} - T_{2,d}) / (t_{2,d} - t_{1,d}) \\
 &= (140.0 - 119.3) / (97.0 - 75.0) \\
 &= 0.9409 \\
 T_{1,d} &= 140.0 \\
 t_{1,d} &= 75.0 \\
 T_{2,d} &= 119.3 \\
 t_{2,d} &= 97.0
 \end{aligned}$$

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 Figure 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 $R \neq 1$

$$\begin{aligned}
 F &= \left[\left(R^2 + 1 \right)^{1/2} / (R - 1) \right] \\
 &\quad \left[\ln \left[(1 - P) / (1 - PR) \right] \right] \\
 &\quad / \ln \left\{ 2 - P \left[R + 1 - \left(R^2 + 1 \right)^{1/2} \right] \right\} \\
 &\quad / \left\{ 2 - P \left[R + 1 + \left(R^2 + 1 \right)^{1/2} \right] \right\}
 \end{aligned}$$

For $R = 1$

$$\begin{aligned}
 F &= [P / (1 - P)] \\
 &\quad \left(2^{1/2} / \ln \left\{ [2 - P(2 - 2^{1/2})] / [2 - P(2 + 2^{1/2})] \right\} \right)
 \end{aligned}$$

Additional equations are available for other flow arrangements, and can be found in the references in paras. 3.2(h) through 3.2(j).

$$\begin{aligned}
 LMTD_d &= 43.65 \\
 MTD_d &= 41.85
 \end{aligned}$$

C-2.1.3 Calculate U_d

$$U_d = Q_d / (A_{o,d})(MTD_d)$$

where

$A_{o,d}$ = total effective surface area, ft², 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-ft²-°F, based on outside surface area, at design accident conditions¹

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 of this Part, section B-6 for precautions related to effective surface areas.

C-2.1.3.1 Data Set (for a Counterflow Heat Exchanger)

$$\begin{aligned}
 A_{o,d} &= 5,080 \\
 MTD_d &= 41.85 \\
 Q_d &= 65,870,000 \\
 U_d &= 309.8
 \end{aligned}$$

C-2.1.4 Calculate r_w (for Back-Calculating $h_{o,d}$). 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

$$r_w = \frac{A_{o,d} d_o \ln[d_o / (d_o - 2t)]}{24k(A_{o,tube})}$$

where

$A_{o,d}$ = total effective surface area, ft², based on outside surface area, including any fin area, at design accident conditions, from design specification sheet

$A_{o,tube}$ = total bare tube surface area, ft², 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-ft²-°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

¹ U_d may also be obtained from technical specifications and design specification sheets.

C-2.1.4.1 Data Set (for a Counterflow Heat Exchanger)

$$\begin{aligned}
 d_o &= 0.75 \\
 k &= 8.754 \\
 n &= n/a \text{ (bare tubes)} \\
 r_w &= 0.0004999 \\
 t &= 0.049 \\
 z &= n/a \text{ (bare tubes)}
 \end{aligned}$$

C-2.1.5 Calculate Re_d (for Back-Calculating $h_{o,d}$)

$$Re_d = (124p_d V_d d_i) / \mu_d$$

where

$$\begin{aligned}
 d_i &= \text{inside diameter of tube, in} \\
 Re_d &= \text{Reynolds number (dimensionless) of the tube side fluid at design accident conditions} \\
 V_d &= \text{tube velocity, ft/sec, based on flow rate and cross-sectional flow area, at design accident conditions} \\
 \mu_d &= \text{bulk absolute viscosity, centipoise, of the tube side fluid at design accident conditions, from the reference in para. 3.2(f)} \\
 \rho_d &= \text{bulk density, lbm/ft}^3, \text{ of the tube side fluid at design accident conditions, from the reference in para. 3.2(f)}
 \end{aligned}$$

C-2.1.5.1 Data Set (for a Counterflow Heat Exchanger)

$$\begin{aligned}
 d_i &= 0.652 \\
 Re_d &= 49,400 \text{ (definitely turbulent flow)} \\
 V_d &= 7.83 \\
 \mu_d &= 0.7966 \\
 \rho_d &= 62.16
 \end{aligned}$$

C-2.1.6 Calculate Pr_d (for Back-Calculating $h_{o,d}$)

$$Pr_d = (2.42Cp_d \mu_d) / k_d$$

where

$$\begin{aligned}
 Cp_d &= \text{specific heat, Btu/lbm} \cdot ^\circ\text{F, of the tube side fluid at design accident conditions, from the reference in para. 3.2(e)} \\
 k_d &= \text{bulk thermal conductivity, Btu/hr-ft} \cdot ^\circ\text{F, of the tube side fluid at design accident conditions, from the reference in para. 3.2(e)} \\
 Pr_d &= \text{Prandtl number (dimensionless) of the tube side fluid at design accident conditions} \\
 \mu_d &= \text{bulk absolute viscosity, centipoise, of the tube side fluid at design accident conditions, from the reference in para. 3.2(f)}
 \end{aligned}$$

C-2.1.6.1 Data Set (for a Counterflow Heat Exchanger)

$$\begin{aligned}
 Cp_d &= 0.9982 \\
 k_d &= 0.3556 \\
 Pr_d &= 5.411
 \end{aligned}$$

$$\mu_d = 0.7966$$

C-2.1.7 Calculate $h_{i,d}$ (for Back-Calculating $h_{o,d}$). 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

$$\begin{aligned}
 d_i &= \text{inside diameter of tube, in.} \\
 h_{i,d} &= \text{inside film coefficient, Btu/hr-ft}^2 \cdot ^\circ\text{F, based on inside surface area, at design accident conditions} \\
 k_d &= \text{bulk thermal conductivity, Btu/hr-ft} \cdot ^\circ\text{F, of the tube side fluid at design accident conditions, from the reference in para. 3.2(e)} \\
 L &= \text{total length of tube, in., carrying flow, from design specification sheet or drawings} \\
 Pr_d &= \text{Prandtl number (dimensionless) of the tube side fluid at design accident conditions} \\
 Re_d &= \text{Reynolds number (dimensionless) of the tube side fluid at design accident conditions} \\
 \mu_d &= \text{bulk absolute viscosity, centipoise, of the tube side fluid at design accident conditions, from the reference in para. 3.2(f)} \\
 \mu_{w,d} &= \text{absolute viscosity, centipoise, of the tube side fluid at the tube wall temperature at design accident conditions, from the reference in para. 3.2(f)}
 \end{aligned}$$

C-2.1.7.1 Data Set (for a Counterflow Heat Exchanger)

$$\begin{aligned}
 d_i &= 0.652 \\
 h_{i,d} &= 1503 \\
 k_d &= 0.3556 \\
 L &= n/a \text{ (turbulent flow)} \\
 Pr_d &= 5.411 \\
 Re_d &= 49,400 \\
 \mu_d &= 0.7966 \\
 \mu_{w,d} &= 0.7966 \text{ (use same value as } \mu_d \text{ for this temperature range)}
 \end{aligned}$$

C-2.1.8 Calculate E_f (for Back-Calculating $h_{o,d}$)

$$E_f = 1 - [A_{fin,d}/A_{o,d}][1 - \eta]$$

where

$$A_{fin,d} = \text{total fin surface area, ft}^2, \text{ at design accident conditions}$$

$A_{o,d}$ = total effective surface area, ft², 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 Figure C-4.1 of 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.

$$d_{fin} = \left[(4A_{sheet}/n\pi) + d_o^2 \right]^{1/2}$$

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 .

$$(1/h_{fin,d}) = (1/h_{o,d}) + r_{o,d}$$

where

$h_{fin,d}$ = film coefficient of fin, Btu/hr-ft²-°F, at design accident conditions

$h_{o,d}$ = outside film coefficient, Btu/hr-ft²-°F, based on outside surface area, at design accident conditions

$r_{o,d}$ = outside fouling resistance, hr-ft²-°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, Back-Calculate $h_{o,d}$

$$U_d = 1/[r_{o,d}(1/E_f) + r_{i,d}(A_{o,d}/A_{i,d}) + (1/h_{o,d})(1/E_f) + r_w + (1/h_{i,d})(A_{o,d}/A_{i,d})]$$

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, ft², based on inside surface area, including any fin area, at design accident conditions

$A_{o,d}$ = total effective surface area, ft², 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-ft²-°F, based on inside surface area, at design accident conditions

$h_{o,d}$ = outside film coefficient, Btu/hr-ft²-°F, based on outside surface area, at design accident conditions

$r_{i,d}$ = inside fouling resistance, hr-ft²-°F/Btu, based on inside surface area, assumed for design accident conditions, from design specification sheet

$r_{o,d}$ = outside fouling resistance, hr-ft²-°F/Btu, based on outside surface area, assumed for design accident conditions, from design specification sheet

r_w = tube wall resistance, hr-ft²-°F/Btu, based on outside surface area, at design accident conditions

U_d = overall heat transfer coefficient, Btu/hr-ft²-°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)

$$A_{o,d}/A_{i,d} = 1.15$$

$$E_f = 1.0$$

$$h_{i,d} = 1,503$$

$$h_{o,d} = 2,581$$

$$r_{i,d} = 0.0005$$

$$r_{o,d} = 0.001$$

$$r_w = 0.0004999$$

$$U_d = 309.8$$

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 back-calculation 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 of this Part) 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

$$Q_{p,t} = W_{p,t}[C_{p,t}(T_{1,t} - T_{2,t})]$$

For cooling fluid

$$Q_{c,t} = W_{c,t}[C_{p,t}(t_{1,t} - t_{2,t})]$$

where

$C_{p,t}$ = bulk specific heat, Btu/lbm-°F, of the cooling fluid at test conditions, from the reference in para. 3.2(e)

$C_{p,t}$ = 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)

$C_{p,c,t} = 0.9988$

$Q_t = 56,030,000$

$t_{1,t} = 60.0$

$t_{2,t} = 78.7$

$W_{c,t} = 3,000,000$ (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 Figures B-1 through B-9 of the reference in para. 3.1(b) or Figures 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 Figure 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 $R \neq 1$

$$F = \left[\left(R^2 + 1 \right)^{1/2} / (R - 1) \right] \left[\ln \left[(1 - P) / (1 - PR) \right] / \ln \left\{ 2 - P \left[R + 1 - \left(R^2 + 1 \right)^{1/2} \right] \right\} / \left\{ 2 - P \left[R + 1 + \left(R^2 + 1 \right)^{1/2} \right] \right\} \right]$$

For $R = 1$

$$F = [P / (1 - P)] \left(2^{1/2} / \ln \left\{ [2 - P(2 - 2^{1/2})] / [2 - P(2 + 2^{1/2})] \right\} \right)$$

Additional equations are available for other flow arrangements, and can be found in the references in paras. 3.2(h) through 3.2(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, ft², 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-ft²-°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)

$$\begin{aligned}
 A_{o,t} &= 5,080 \text{ (note, there is no tube plugging accounted for here)} \\
 MTD_t &= 37.52 \\
 Q_t &= 56,030,000 \\
 U_t &= 294.0
 \end{aligned}$$

C-2.2.6 Calculate U_t (NTU Method)

$$U_t = (NTU_t)(W_{c,t})(Cp_{c,t})/A_{o,t}$$

where

$$\begin{aligned}
 A_{o,t} &= \text{total effective surface area, ft}^2, \text{ based on outside surface area, including any fin area, and any reduction in area due to plugged tubes, at test conditions} \\
 Cp_{c,t} &= \text{bulk specific heat, Btu/lbm-}^\circ\text{F, of cooling fluid at test conditions, from the reference in para. 3.2(e)} \\
 NTU_t &= \text{number of transfer units (dimensionless) at test conditions} \\
 U_t &= \text{overall heat transfer coefficient, Btu/hr-ft}^2\text{-}^\circ\text{F, based on outside surface area, at test conditions} \\
 W_{c,t} &= \text{cooling fluid flow rate, lbm/hr, at test conditions}
 \end{aligned}$$

NTU_t is a function of R_t and P_t , and can be obtained from Figures B-10 through B-12 of the reference in para. 3.1(b) or Figures T-3.3 through T-3.3B of the reference in para. 3.1(a).

$$\begin{aligned}
 R_t &= (T_{1,t} - T_{2,t})/(t_{2,t} - t_{1,t}) \\
 P_t &= (t_{2,i} - t_{1,t})/(T_{1,t} - t_{1,t})
 \end{aligned}$$

where

$$\begin{aligned}
 P_t &= \text{thermal effectiveness (dimensionless) at test conditions} \\
 R_t &= \text{capacity rate ratio (dimensionless) at test conditions} \\
 T_{1,t} &= \text{process fluid inlet temperature, }^\circ\text{F, at test conditions} \\
 t_{1,t} &= \text{cooling fluid inlet temperature, }^\circ\text{F, at test conditions} \\
 T_{2,t} &= \text{process fluid outlet temperature, }^\circ\text{F, at test conditions} \\
 t_{2,t} &= \text{cooling fluid outlet temperature, }^\circ\text{F, at test conditions}
 \end{aligned}$$

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_{cb} , and Cp_c shall be for the tube side fluid.

C-2.2.6.1 Data Set (for a Counterflow Heat Exchanger)

$$\begin{aligned}
 NTU_t &= 0.5 \\
 P_t &= (78.7 - 60)/(120 - 60) \\
 &= 0.3117 \\
 R_t &= (120 - 97.5)/(78.8 - 60) \\
 &= 1.203 \\
 T_{1,t} &= 120 \\
 t_{1,t} &= 60 \\
 T_{2,t} &= 97.5 \\
 t_{2,t} &= 78.7
 \end{aligned}$$

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 Figure 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 $R = \text{infinity}$

$$NTU = \ln[1/(1 - P)]$$

For $R \neq 0$ and $R \neq \text{infinity}$

$$\begin{aligned}
 NTU &= \left[1/(R^2 + 1)^{1/2} \right] \\
 &\quad \left[\ln \left\{ 2 - P \left[R + 1 - (R^2 + 1)^{1/2} \right] \right\} \right. \\
 &\quad \left. / \left\{ 2 - P \left[R + 1 + (R^2 + 1)^{1/2} \right] \right\} \right]
 \end{aligned}$$

Additional equations are available for other flow arrangements, and can be found in the references in paras. 3.2(h) through 3.2(l).

$$\begin{aligned}
 A_{o,t} &= 5,080 \\
 Cp_{c,t} &= 0.9988 \\
 U_t &= 294.9 \\
 W_{c,t} &= 3,000,000
 \end{aligned}$$

C-2.2.7 Calculate Re_t

$$Re_t = (124\rho_t V_t d_i)/\mu_t$$

where

$$\begin{aligned}
 d_i &= \text{inside diameter of tube, in.} \\
 Re_t &= \text{Reynolds number (dimensionless) of the tube side fluid at test conditions} \\
 V_t &= \text{tube velocity, ft/sec, based on flow rate and cross-sectional flow area, at test conditions} \\
 \mu_t &= \text{bulk absolute viscosity, centipoise, of the tube side fluid at test conditions, from the reference in para. 3.2(f)} \\
 \rho_t &= \text{bulk density, lbm/ft}^3, \text{ of the tube side fluid at test conditions, from the reference in para. 3.2(f)}
 \end{aligned}$$

C-2.2.7.1 Data Set (for a Counterflow Heat Exchanger)

$$\begin{aligned}d_t &= 0.652 \\ \text{Re}_t &= 39,900 \\ V_t &= 7.8 \\ \mu_t &= 0.9847 \\ \rho_t &= 62.31\end{aligned}$$

C-2.2.8 Calculate Pr_t

$$\text{Pr}_t = (2.42 C_{p_t} \mu_t) / k_t$$

where

C_{p_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)

$$\begin{aligned}C_{p_t} &= 0.9988 \\ k_t &= 0.3474 \\ \text{Pr}_t &= 6.851 \\ \mu_t &= 0.9847\end{aligned}$$

C-2.2.9 Calculate $h_{i,t}$. For turbulent flow, $\text{Re}_t > 10,000$

$$h_{i,t} = 0.023(12k_t/d_i)(\text{Re}_t)^{0.8}(\text{Pr}_t)^{1/3}(\mu_t/\mu_{w,t})^{0.14}$$

For laminar flow, $\text{Re}_t < 2,100$

$$h_{i,t} = 1.86(12k_t/d_i)(\text{Re}_t)^{1/3}(\text{Pr}_t)^{1/3}(d_i/L)^{1/3}(\mu_t/\mu_{w,t})^{0.14}$$

where

d_i = inside diameter of tube, in.
 $h_{i,t}$ = inside film coefficient, Btu/hr-ft²-°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)

$$\begin{aligned}d_i &= 0.652 \\ h_{i,t} &= 1,339 \\ k_t &= 0.3474 \\ L &= \text{n/a (turbulent flow)} \\ \text{Pr}_t &= 6.851 \\ \text{Re}_t &= 39,900 \\ \mu_t &= 0.9847 \\ \mu_{w,t} &= 0.9847 \text{ (use same value as } \mu_t \text{ for this temperature range)}\end{aligned}$$

C-2.2.10 Calculate $h_{o,t}$ (Ratio Method)

$$h_{o,t} = h_{o,d}(W_t/W_d)^{0.6}(\mu_t/\mu_d)^{-0.27}(C_{p_t}/C_{p_d})^{1/3}(k_t/k_d)^{2/3}$$

where

C_{p_d} = bulk specific heat, Btu/lbm-°F, of the shell side fluid at design accident conditions, from the reference in para. 3.2(e)
 C_{p_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-ft²-°F, based on outside surface area, at design accident conditions
 $h_{o,t}$ = outside film coefficient, Btu/hr-ft²-°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)

$$\begin{aligned}C_{p_d} &= 0.9990 \\ C_{p_t} &= 0.9985 \\ h_{o,d} &= 2,581 \\ h_{o,t} &= 2,081 \\ k_d &= 0.3730\end{aligned}$$

$$\begin{aligned}
 k_t &= 0.3653 \\
 W_d &= 3,200,000 \\
 W_t &= 2,500,000 \\
 \mu_d &= 0.5050 \\
 \mu_t &= 0.6146
 \end{aligned}$$

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)

$$h_{o,t} = n/a \text{ (using back-calculation method)}$$

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

$$\begin{aligned}
 A_{i,t} &= \text{inside effective surface area, ft}^2, \text{ based on inside surface area, including any fin area, and any reduction in area due to plugged tubes, at test conditions} \\
 A_{o,t} &= \text{total effective surface area, ft}^2, \text{ based on outside surface area, including any fin area, and any reduction in area due to plugged tubes, at test conditions} \\
 A_{o,t}/A_{i,t} &= \text{ratio of total to inside effective surface area (dimensionless) at test conditions} \\
 E_f &= \text{weighted fin efficiency (dimensionless, equal to 1 for nonfinned tubes, less than 1 for finned tubes)} \\
 h_{i,t} &= \text{inside film coefficient, Btu/hr-ft}^2\text{-}^\circ\text{F, based on inside surface area, at test conditions} \\
 h_{o,t} &= \text{outside film coefficient, Btu/hr-ft}^2\text{-}^\circ\text{F, based on outside surface area, at test conditions} \\
 r_{i,t} &= \text{inside fouling resistance, hr-ft}^2\text{-}^\circ\text{F/Btu, based on inside surface area, at test conditions}^2 \\
 r_{o,t} &= \text{outside fouling resistance, hr-ft}^2\text{-}^\circ\text{F/Btu, based on outside surface area, at test conditions}^2
 \end{aligned}$$

r_t = total fouling resistance, hr-ft²-°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-ft²-°F/Btu, based on outside surface area, at design accident conditions

U_t = overall heat transfer coefficient, Btu/hr-ft²-°F, based on outside surface area, at test conditions

C-2.2.12.1 Data Set (for a Counterflow Heat Exchanger)

$$A_{o,t}/A_{i,t} = 1.150$$

$$E_f = 1.0$$

$$h_{i,t} = 1,339$$

$$h_{o,t} = 2081$$

$$r_t = 0.001562$$

$$r_w = 0.0004999$$

$$U_t = 294.0$$

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

$$\begin{aligned}
 A_{i,t} &= \text{inside effective surface area, ft}^2, \text{ based on inside surface area, including any fin area, and any reduction in area due to plugged tubes, at test conditions} \\
 A_{o,t} &= \text{total effective surface area, ft}^2, \text{ based on outside surface area, including any fin area, and any reduction in area due to plugged tubes, at test conditions} \\
 A_{o,t}/A_{i,t} &= \text{ratio of total to inside effective surface area (dimensionless) at test conditions} \\
 E_f &= \text{weighted fin efficiency (dimensionless, equal to 1 for nonfinned tubes, less than 1 for finned tubes)} \\
 h_{i,d} &= \text{inside film coefficient, Btu/hr-ft}^2\text{-}^\circ\text{F, based on inside surface area, at design accident conditions} \\
 h_{o,d} &= \text{outside film coefficient, Btu/hr-ft}^2\text{-}^\circ\text{F, based on outside surface area, at design accident conditions} \\
 r_{i,t} &= \text{inside fouling resistance, hr-ft}^2\text{-}^\circ\text{F/Btu, based on inside surface area, at test conditions} \\
 r_{o,t} &= \text{outside fouling resistance, hr-ft}^2\text{-}^\circ\text{F/Btu, based on outside surface area, at test conditions} \\
 r_t &= \text{total fouling resistance, hr-ft}^2\text{-}^\circ\text{F/Btu, based on outside surface area, at test conditions} \\
 &= r_{o,t}(1/E_f) + r_{i,t}(A_{o,t}/A_{i,t})
 \end{aligned}$$

² Assume the design value (or zero) for either $r_{i,t}$ or $r_{o,t}$ (whichever one is not calculated).

r_w = tube wall resistance, $\text{hr}\cdot\text{ft}^2\cdot^\circ\text{F}/\text{Btu}$, based on outside surface area, at design accident conditions

U_p = overall heat transfer coefficient, $\text{Btu}/\text{hr}\cdot\text{ft}^2\cdot^\circ\text{F}$, 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)

$$A_{o,t}/A_{i,t} = 1.150$$

$$E_f = 1.0$$

$$h_{i,d} = 1,503$$

$$h_{o,d} = 2,581$$

$$r_t = 0.001562$$

$$r_w = 0.0004999$$

$$U_p = 311.1$$

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, $^\circ\text{F}$, 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, $\text{Btu}/\text{hr}\cdot\text{ft}^2\cdot^\circ\text{F}$, 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)

$$A_{o,t} = 5,080$$

$$MTD_d = 41.85$$

$$Q_p = 66,140,000$$

$$U_p = 311.1$$

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 $mC_p\Delta T$, 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:

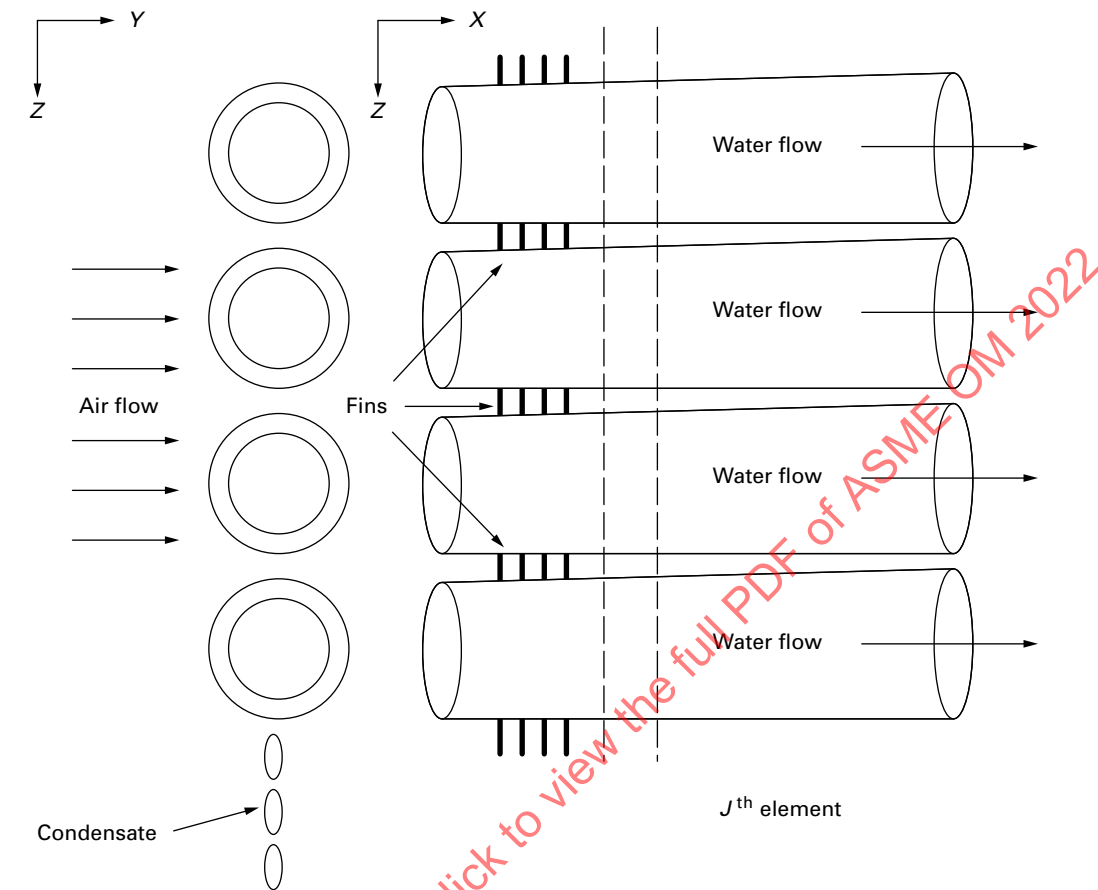
- (a) process fluid (steam–air mixture) pressure
- (b) cooling fluid inlet temperature
- (c) cooling fluid outlet temperature
- (d) process fluid (steam–air mixture) inlet temperature
- (e) process fluid (steam–air mixture) outlet temperature
- (f) cooling fluid flow rate
- (g) process fluid (steam–air mixture) inlet relative humidity

C-3.2 Write the Finite Difference Equations

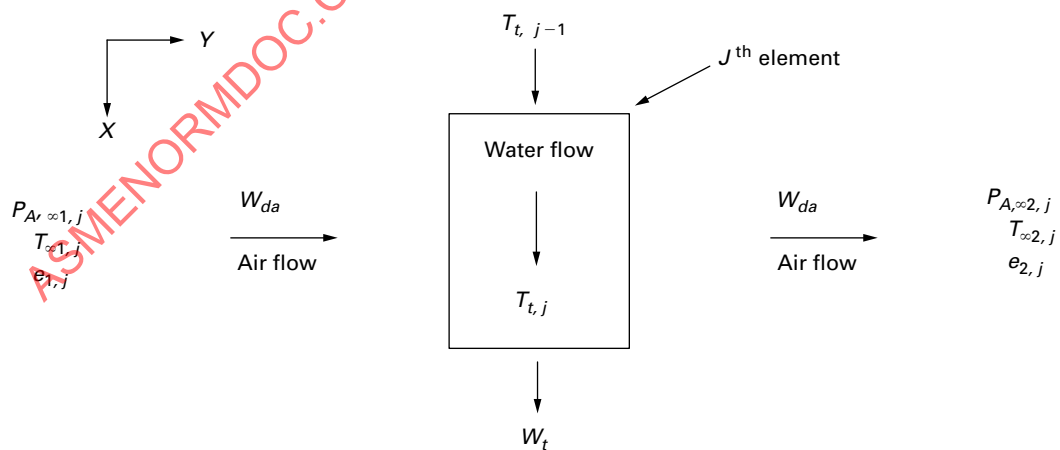
Write the finite difference equations of the heat transfer process. Equations (C-1) through (C-24) are shown here as a guide. These equations are for a cross-flow unmixed heat exchanger having only one tube row with fins on the outside. Figure C-1 shows this heat exchanger along with its j^{th} finite element bounded by two parallel planes in the y - z plane. The airflow 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.

Figure C-1
One Tube Row Air-to-Water Cross-Flow Heat Exchanger

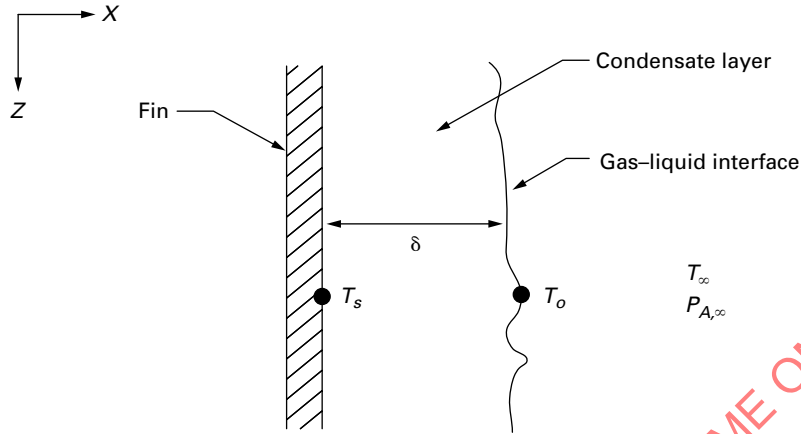


(a) Heat Exchanger and Fins



(b) Jth Element

Figure C-2
Fin, Condensate Layer, and Interfaces



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:

$$W_{da}(\phi_{1,j} - \phi_{2,j}) = W_{\text{cond},j} \quad (\text{C-1})$$

$$W_{da}(\phi_{1,j} - \phi_{2,j}) = M_A N_{A,j} \left(\frac{A}{b} \right) \quad (\text{C-2})$$

$$\phi_{1,j} = \phi_{\text{in}}; 1 \leq j \leq N$$

where

- A = total outside heat transfer area, 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:

$$W_{da}(e_{1,j} - e_{2,j}) = U_j \left(\frac{A}{b} \right) \left[\frac{1}{2}(T_{\infty 1,j} + T_{\infty 2,j}) - T_{1,j} \right] + (W_{\text{cond},j})(e_{\text{cond},j}) \quad (\text{C-3})$$

$$e_{1,j} = e_{\text{in}}$$

$$T_{\infty 1,j} = T_{\infty, \text{in}}; 1 \leq j \leq N \quad (\text{C-4})$$

$$e = f_1(\phi, T_{\infty})$$

where

- A = total outside heat transfer area, ft^2
= $A_{\text{fin}} + A_{t,\text{exp}}$ [see eq. (C-6)]
- b = length of heat exchanger along water flow direction, ft
- $e_{1,j}$ = 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, $^{\circ}\text{F}$, of air-vapor mixture
- $T_{\infty 1,j}$ = temperature, $^{\circ}\text{F}$, of air-vapor mixture upstream of the tube row of j^{th} element of the heat exchanger
- $T_{\infty 2,j}$ = temperature, $^{\circ}\text{F}$, of air-vapor mixture downstream of the tube row of j^{th} element of the heat exchanger
- $T_{\infty, \text{in}}$ = temperature, $^{\circ}\text{F}$, of air-vapor mixture at inlet
- $T_{t,j}$ = tube side fluid temperature, $^{\circ}\text{F}$, of j^{th} element of the heat exchanger

- U_i = overall heat transfer coefficient, Btu/hr-ft²-°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:

$$(WCp)_t(T_{t,j} - T_{t,j-1}) = U_j(\Delta A) \left[\frac{1}{2}(T_{\infty 1,j} + T_{\infty 2,j}) - T_{t,j} \right] \quad (C-5)$$

$$1 \leq j \leq N$$

$$T_{t,0} = T_{t,\text{in}} \quad \text{and} \quad T_{t,\text{out}} = T_{t,N}$$

where

- A = total outside heat transfer area, ft²
 $= A_{\text{fin}} + A_{b,\text{exp}}$ [see eq. (C-6)]
- ΔA = area, ft², 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
- $T_{t,j-1}$ = 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-ft²-°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 evaluate 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:

$$\frac{1}{U_j(A_{\text{fin}} + A_{t,\text{exp}})} = \frac{1}{h_{\text{fin},j}(\eta_j A_{\text{fin}} + A_{t,\text{exp}})} + \frac{d_o \ln(d_o / d_i)}{2k_{\text{wall}}A_o} + \frac{1}{A_i} \left(\frac{1}{h_i} + r_{fi} \right) \quad (C-6)$$

where

- A_{fin} = surface area of the fins, ft²
- A_i = inside area of the tubes, ft²
- A_o = outside area of the tubes, ft²
- $A_{t,\text{exp}}$ = outside exposed area of tubes, ft²; 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-ft²-°F, associated with the fin surface of j^{th} element of the heat exchanger
- h_i = tube side heat transfer coefficient, Btu/hr-ft²-°F
- k_{wall} = thermal conductivity of the tube wall material, Btu/hr-ft-°F
- r_{fi} = inside fouling resistance, hr-ft²-°F/Btu
- U_j = overall heat transfer coefficient, Btu/hr-ft²-°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:

$$q_j = \frac{k_{\text{cond}}}{\delta_j}(T_{o,j} - T_{s,j}) \quad (C-7)$$

$$q_j = h_{\text{out},j}(T_{\infty,j} - T_{o,j}) \quad (C-8)$$

$$q_j = U_j(T_{\infty,j} - T_{t,j}) \quad (C-9)$$

where

- $h_{\text{out},j}$ = outside heat transfer coefficient, Btu/hr-ft²-°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-ft², 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-ft²-°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

$$T_{\infty,j} = \frac{1}{2}(T_{\infty 1,j} + T_{\infty 2,j}) \quad (\text{C-11})$$

$$T_{\text{cond},j} = \frac{1}{2}(T_{o,j} + T_{s,j}) \quad (\text{C-12})$$

where

h_{fg} = heat of condensation of the vapor, Btu/lbm

h_j = outside heat transfer coefficient, Btu/hr-ft²-°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-ft², of j^{th} element of the heat exchanger

q_j = local heat transfer rate per unit outside area, Btu/hr-ft², 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-ft², 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-ft², 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:

$$h_j = \frac{N_{A,j} C_A}{1 - e^{-(N_{A,j} C_A / h_j)}} \quad (\text{C-15})$$

where

C_A = molar specific heat, Btu/lbm-mole-°F, of pure vapor

h_j = outside heat transfer coefficient, Btu/hr-ft²-°F, in noncondensing situation of j^{th} element of the heat exchanger

h_j = outside heat transfer coefficient, Btu/hr-ft²-°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-ft², 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:

$$p_{A,o,j} = p_{\text{sat}}(T_{o,j}) \quad (\text{C-16})$$

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:

$$\phi_{1,j} = \frac{M_A}{M_{da}} \left(\frac{p_{A,\infty 1,j}}{p_{\text{tot}} - p_{A,\infty 1,j}} \right) \quad (\text{C-17})$$

$$\phi_{2,j} = \frac{M_A}{M_{da}} \left(\frac{p_{A,\infty 2,j}}{p_{\text{tot}} - p_{A,\infty 2,j}} \right) \quad (\text{C-18})$$

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,

$$\frac{1}{h_{\text{fin},j}} = \frac{1}{h_{\text{out},j}} + r_{f,o} + \frac{\delta_j}{k_{\text{cond}}} \quad (\text{C-19})$$

where

- $h_{\text{fin},j}$ = heat transfer coefficient, Btu/hr-ft²-°F, associated with the fin surface of j^{th} element of the heat exchanger
 $h_{\text{out},j}$ = outside heat transfer coefficient, Btu/hr-ft²-°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-ft²-°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:

$$\delta_j = \frac{3}{4} \left[\frac{3\mu N_{A,j} M_A L}{\rho_1(\rho_1 - \rho_v)g} \right]^{1/3} \quad (\text{C-20})$$

where

- g = acceleration due to gravity, ft/hr²
 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-ft², 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/ft³, of the condensate
 ρ_v = density, lbm/ft³, 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:

$$k_A = \frac{h}{C} \left(\frac{\text{Pr}}{\text{Sc}} \right)^{2/3} \quad (\text{C-21})$$

where

- C = molar specific heat, Btu/lbm-mole-°F, of the air-vapor mixture
 h = outside heat transfer coefficient, Btu/hr-ft²-°F, in noncondensing situation
 k_A = mass transfer coefficient, lbm-mole/hr-ft², 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:

$$e_{\text{out}} = \frac{1}{N} \sum_{j=1}^N e_{2,j} \quad (\text{C-22})$$

$$\phi_{\text{out}} = \frac{1}{N} \sum_{j=1}^N \phi_{2,j} \quad (\text{C-23})$$

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:

$$T_{\infty,\text{out}} = f_2(e_{\text{out}}, \phi_{\text{out}}) \quad (\text{C-24})$$

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 24 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) through (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-airflow rate. The combination of these two values that matches with the two measured outlet temperatures is the proper airflow 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 section 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

C-4.2.1 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

C-4.2.2 In addition, record one of the following two parameters:

- (a) cooling fluid outlet temperature time history
- (b) 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 $(p + 1)^{\text{th}}$ 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 $(j - 1)^{\text{th}}$ 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 $(j - 1)^{\text{th}}$ 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 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.

Figure C-3
Schematic Representation of a Countercurrent Shell-and-Tube Heat Exchanger

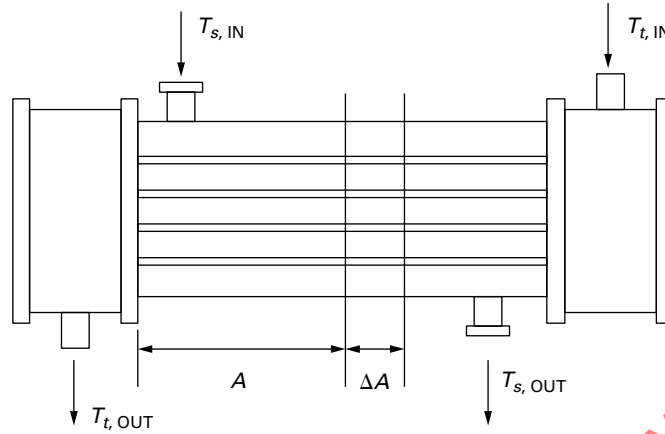
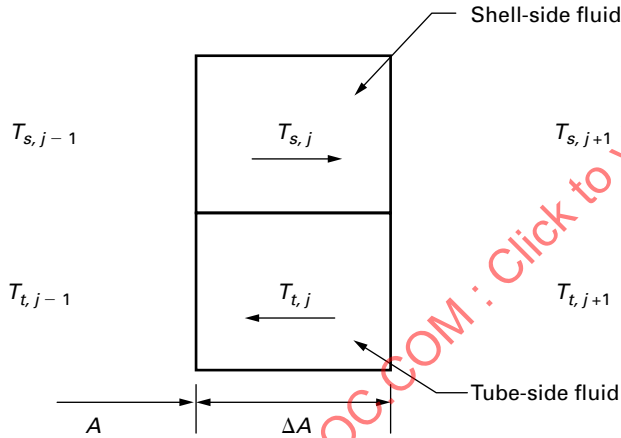


Figure C-4
A Small Element of a Countercurrent Shell-and-Tube Heat Exchanger



Solving for the unknown temperature,

$$T_{s,j}^{p+1} = \frac{(WCp)_s (\Delta t)}{\Delta(mc)_s} T_{s,j-1}^p + \left[1 - \frac{[(WCp)_s + U(\Delta A) \Delta t]}{\Delta(mc)_s} \right] T_{s,j}^p + \frac{U(\Delta A) \Delta t}{\Delta(mc)_s} T_{t,j}^p; 1 \leq j \leq N \quad (C-25)$$

where all variables are as defined above.

From the shell side inlet boundary condition,

$$T_{s,0}^p = T_{s,in}^p \quad (C-26)$$

where

$T_{s,in}^p$ = inlet temperature of the shell fluid at the p^{th} time step

$T_{s,0}^p$ = temperature of the shell side fluid upstream of the first heat exchanger element 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,

$$T_{t,j}^{p+1} = \frac{(WCp)_t (\Delta t)}{\Delta(mc)_t} T_{t,j+1}^p + \left[1 - \frac{[(WCp)_t + U(\Delta A) \Delta t]}{\Delta(mc)_t} \right] T_{t,j}^p + \frac{U(\Delta A) \Delta t}{\Delta(mc)_t} T_{s,j}^p; 1 \leq j \leq N \quad (C-27)$$

where the variables are as defined previously.

From the tube side inlet boundary condition,

$$T_{t,N+1}^p = T_{t,IN}^p \quad (C-28)$$

where

$T_{t,IN}^p$ = 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,

$$T_{s,OUT}^{p+1} = T_{s,N}^{p+1} \quad (C-29)$$

$$T_{t,OUT}^{p+1} = T_{t,1}^{p+1} \quad (C-30)$$

ΔA and Δt must satisfy the inequalities (C-31) and (C-32) simultaneously to satisfy the stability criteria.

$$\Delta t < \frac{\Delta(mc)_s}{(WCp)_s + U(\Delta A)} \quad (C-31)$$

$$\Delta t < \frac{\Delta(mc)_t}{(WCp)_t + U(\Delta A)} \quad (C-32)$$

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.

$$\frac{1}{U} = \frac{1}{h_o} + r_{f,t} + r_w + \frac{d_o}{d_i} \frac{1}{h_i} \quad (C-33)$$

$$r_{f,t} = r_{f,o} + \frac{d_o}{d_i} r_{f,i} \quad (C-34)$$

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 section 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 nodding 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 $\pm 5\%$). 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 (e.g., same valve lineups, header pressures, pump currents, etc.). Both flows should be within $\pm 5\%$ 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

$$\begin{aligned}
 P_t &= 0.3067 \\
 T_{1,t} &= 145.0 \\
 t_{1,t} &= 70.0 \\
 t_{2,t} &= 93.0
 \end{aligned}$$

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 section 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:

$$\begin{aligned}
 T_{1,d} &= 140.0 \\
 t_{1,d} &= 75.0 \\
 T_{2,d} &= 119.3 \\
 t_{2,d} &= 97.0
 \end{aligned}$$

C-5.5.1 If $T_{1,d}$ and $t_{1,d}$ Are Known

$$\begin{aligned}
 t_{2,d} &= t_{1,d} + P_t(T_{1,d} - t_{1,d}) \\
 T_{2,d} &= T_{1,d} - R_t(t_{2,d} - t_{1,d})
 \end{aligned}$$

C-5.5.1.1 Data Set

$$\begin{aligned}
 P_t &= 0.3067 \\
 R_t &= 0.9391 \\
 T_{1,d} &= 140.0 \\
 t_{1,d} &= 75.0 \\
 T_{2,d} &= 121.3^3 \\
 t_{2,d} &= 94.93^3
 \end{aligned}$$

C-5.5.2 If $T_{1,d}$ and $t_{2,d}$ Are Known

$$\begin{aligned}
 t_{1,d} &= t_{2,d} + P_t(t_{2,d} - T_{1,d})/(1 - P_t) \\
 T_{2,d} &= T_{1,d} - R_t(t_{2,d} - t_{1,d})
 \end{aligned}$$

C-5.5.2.1 Data Set

$$\begin{aligned}
 P_t &= 0.3067 \\
 R_t &= 0.9391 \\
 T_{1,d} &= 140.0 \\
 t_{1,d} &= 77.98^3 \\
 T_{2,d} &= 97.0 \\
 t_{2,d} &= 122.1^3
 \end{aligned}$$

C-5.5.3 If $T_{2,d}$ and $t_{1,d}$ Are Known

$$\begin{aligned}
 t_{2,d} &= t_{1,d} + P_t(T_{2,d} - t_{1,d})/(1 - P_t R_t) \\
 T_{1,d} &= T_{2,d} + R_t(t_{2,d} - t_{1,d})
 \end{aligned}$$

C-5.5.3.1 Data Set

$$\begin{aligned}
 P_t &= 0.3067 \\
 R_t &= 0.9391 \\
 T_{1,d} &= 137.2^3 \\
 t_{1,d} &= 75.0 \\
 T_{2,d} &= 119.3 \\
 t_{2,d} &= 94.08^3
 \end{aligned}$$

C-5.5.4 If $T_{2,d}$ and $t_{2,d}$ Are Known

$$\begin{aligned}
 t_{1,d} &= t_{2,d} + P_t(t_{2,d} - T_{2,d})/(1 - P_t R_t - P_t) \\
 T_{1,d} &= T_{2,d} + R_t(t_{2,d} - t_{1,d})
 \end{aligned}$$

C-5.5.4.1 Data Set

$$\begin{aligned}
 P_t &= 0.3067 \\
 R_t &= 0.9391 \\
 T_{1,d} &= 135.1^3 \\
 t_{1,d} &= 80.13^3 \\
 T_{2,d} &= 119.3 \\
 t_{2,d} &= 97.0
 \end{aligned}$$

C-5.5.5 If $T_{1,d}$ and $T_{2,d}$ Are Known

$$\begin{aligned}
 t_{1,d} &= T_{1,d} + (T_{2,d} - T_{1,d})/R_t P_t \\
 t_{2,d} &= t_{1,d} - (T_{2,d} - T_{1,d})/R_t
 \end{aligned}$$

C-5.5.5.1 Data Set

$$\begin{aligned}
 P_t &= 0.3067 \\
 R_t &= 0.9391 \\
 T_{1,d} &= 140.0 \\
 t_{1,d} &= 68.13^3 \\
 T_{2,d} &= 119.3 \\
 t_{2,d} &= 90.17^3
 \end{aligned}$$

C-5.5.6 If $t_{1,d}$ and $t_{2,d}$ Are Known

$$\begin{aligned}
 T_{1,d} &= t_{1,d} + (t_{2,d} - t_{1,d})/P_t \\
 T_{2,d} &= T_{1,d} - R_t(t_{2,d} - t_{1,d})
 \end{aligned}$$

C-5.5.6.1 Data Set

$$\begin{aligned}
 P_t &= 0.3067 \\
 R_t &= 0.9391 \\
 T_{1,d} &= 146.7^3 \\
 t_{1,d} &= 75.0 \\
 T_{2,d} &= 126.1^3 \\
 t_{2,d} &= 97.0
 \end{aligned}$$

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.

³These values should be compared with the para. C-2.1.1.1 data set, with appropriate consideration of uncertainty.

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

$$C_{p,t} = (M_{p,t})(C_{p,t})$$

where

$C_{p,t}$ = thermal capacity of the process fluid, Btu/°F, at test conditions

$C_{p,t}$ = 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

$$C_{p,t} = 100,000,000$$

$$C_{p,t} = 1$$

$$M_{p,t} = 100,000,000$$

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

$$P_t = [C_{p,t}/(W_{c,t}C_{p,t})] \ln[(T_{1,t,i} - t_{1,t})/(T_{1,t,f} - t_{1,t})]$$

where

$C_{p,t}$ = thermal capacity of the process fluid, Btu/°F, at test conditions

$C_{p,t}$ = 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

$$C_{p,t} = 100,000,000$$

$$C_{p,t} = 1$$

$$t_{1,t} = 60$$

$$T_{1,t,f} = 180$$

$$T_{1,t,i} = 200$$

$$W_{c,t} = 1,000,000$$

$$\tau = 20.55$$

Therefore,

$$P_t = 0.75$$

C-6.3 Calculate the Capacity Rate Ratio

$$R_t = W_{c,t}C_{p,t}/W_{p,t}C_{p,t}$$

where

$C_{p,t}$ = heat capacity of the cooling fluid, Btu/lbm-°F, at test conditions, from the reference in para. 3.2(e)

$C_{p,t}$ = 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

$$C_{p,t} = 1$$

$$C_{p,t} = 1$$

$$W_{c,t} = 1,000,000$$

$$W_{p,t} = 833,000$$

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)

$$U_t = (NTU_t)(W_{c,t})(C_{p,c,t})/A_{o,t}$$

where

$A_{o,t}$ = effective external surface area, ft², at test conditions

$C_{p,c,t}$ = 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-ft²-°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

$$A_{o,t} = 10,000$$

$$C_{p,c,t} = 1$$

$$NTU_t = 4.58$$

$$W_{c,t} = 100,000$$

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 $C_{p,c,t}$ 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.

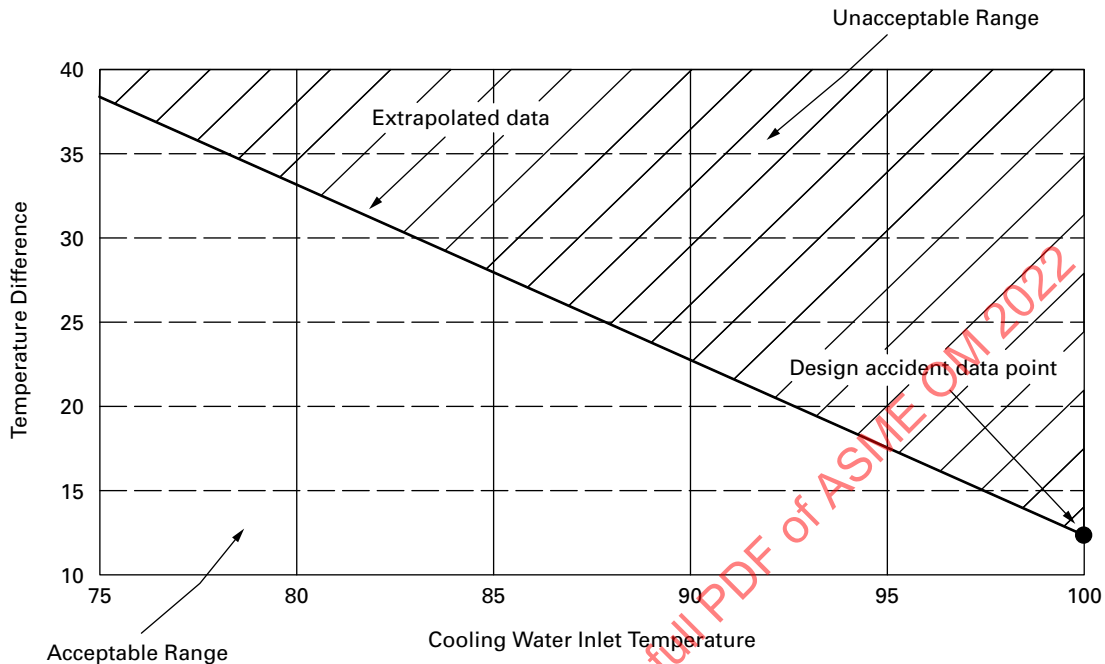
CAUTION: In reality, the EDG might employ a temperature control valve to modulate process flow to the heat exchanger to prevent too much or too little heat from being removed if it detected a process fluid temperature outside a specified range. If this were to occur, significant changes in the process 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 Figure 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 gpm 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.

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-ft²-°F/

Figure C-5
Cooling Water Inlet Temperature Versus Temperature Difference



GENERAL NOTES:

- (a) Temperature difference = ΔT
 (b) Cooling water inlet temperature = t_1

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-ft²-°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-ft²-°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

$t_{1,d}$ = 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

$$t_{1,d} = 100$$

$$T_{2,d} = 112$$

$$\Delta T_d = 12$$

C-7.2 Plot the Design Accident Condition Data

Plot the data point corresponding to $t_{1,d}$ and ΔT_d , as shown in Figure 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 Figure 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 $Q = \dot{m}C_p\Delta T = UA(LMTD)$. 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 Figure 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-ft²-°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

$t_{1,t} = 85$

$T_{2,d} = 112$

$\Delta T_t = 27$

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 of this Part, section 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 of this Part 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 preventive 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 are 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 the 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 are 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 3.2(p) of this Part, 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 in (a) above for each measurement parameter.

For additional details on measurement errors, instrument accuracies, and related topics, see the references in paras. 3.2(n) through 3.2(p) of this Part.

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 the steps in (a) and (b) above 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) of this Part 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 the steps in (a) through (e) above 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 airflow 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) above; there will be one average.
- (c) Determine the differences between the parameter average in (b) above and the average instrument readings in (a) above 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) above 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) above.
- (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) of this Part.

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) of this Part.

(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 RTDs and individual calibration curves applied to each RTD.

(d) When measuring only temperature differences (e.g., ΔT s), 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., ΔT s), apply the bias error to the temperature differences using the ΔT methodology for nonindependent bias limits [see the reference in para. 3.2(o) of this Part].

(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 RTDs, 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) of this Part].

(j) Increase ΔT s by adjusting either of the flow rates prior to the test. However, as the ΔT s (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 of this Part, sections B-1 and B-2).

(k) Increase ΔT s 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 of this Part, section 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 flowmetering 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 flowmeters, magnetic flowmeters, 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 of this Part, section 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) of this Part.

C-11.1.6 Airflows. Accurate airflow 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 deter-

mine the ability to obtain accurate airflow measurements. The following techniques should be used to minimize airflow 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 airflow) 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 of this Part).

(b) Locate airflow sensors in straight, unobstructed sections of ductwork according to accepted industry standards [i.e., references in paras. 3.2(r) through 3.2(u) of this Part].

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 section 9 of this Part).

C-11.4 Calculated Parameters

All test condition calculations shall be performed using the most accurate measured parameters as the required parameters (see section 6 of this Part). The other param-

eters (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) of this Part 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 of this Part for potential causes.

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

0.3x: 0.3 times the machine running speed.

0.5x: 0.5 times the machine running speed.

1x: the machine running speed in cpm.

1x amplitude: vibration amplitude at running speed. (See also *harmonics*.)

1x vectors: the vector of vibration, amplitude, and phase, at the machine running speed.

2x: twice the machine running speed.

2x amplitude: vibration amplitude at twice running speed. (See also *harmonics*.)

2x 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./sec² = 32.17 ft/sec² = 9.81 m/s².

accelerometer: an inertial transducer that converts the acceleration of mechanical vibration into a proportional electric signal.

acceptance region: area around the 1x or 2x 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.

Bodé 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 non-uniform 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 (1x).

***Nx* 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 (1x). (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.

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Publisher: American Petroleum Institute (API), 200 Massachusetts Avenue NW, Suite 1100, Washington, DC 20001-5571 (www.api.org)

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), Two Park Avenue, New York, NY 10016-5990 (www.asme.org)

ASTM D6224, In-service Monitoring of Lubrication Oil for Auxiliary Power Plant Equipment

ASTM E1934, Guide for Examining Electrical and Mechanical Equipment with Infrared Thermography
Publisher: American Society for Testing and Materials (ASTM International), 100 Barr Harbor Drive, P.O. Box C700, West Conshohocken, PA 19428-2959

NEMA MG 1, Motors and Generators

Publisher: National Electrical Manufacturers Association (NEMA), 1300 North 17th Street, Suite 900, Arlington, VA 22209 (www.nema.org)

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	1x and occasionally 2x vectors, non- circular orbit, bearing temperature rise	Bearing temperature, orbit, oil properties, spectra, trend, and vector
Hydraulic instability	Nonsynchronous, random vibration < 1x speed	Average spectra and trend
Bearing instability	Vibration at 0.3x to <0.5x 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 1x speed	Orbit, spectra, and vector
Cracked shaft	Changes in 1x and 2x amplitude and phase	Orbit, spectra, trend, and vector
Unbalance	1x vectors and a typically circular orbit	Orbit, trend, and vector
Worn/damaged bearings	1x amplitude or increase in harmonic amplitudes	Bearing temperature, orbit, oil properties, spectra, trend, and vector
Looseness	1x vector increase, harmonics of running speed, truncated waveforms	Spectra, waveform, and trend
Coupling misalignment or damage (angular/parallel)	1x and occasionally 2x 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	Excessive leakage	Trend and correlation of seal parameters, such as flow, temperature, and pressure
Chipped	Failure to stage	
Cracked seal faces	Increment in cavity temperature	
Pinched or cut elastomers	Increase or decrease of bleedoff flow	
Wear	Increase of bleedoff or leakage	
Dirt accumulation	temperature	
Blocked controlled bleedoff	Unbalanced seal pressure and temperatures	
	Seal pressure oscillations (spikes)	
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.

Table 3
Electrical Motor Faults

Possible Faults	Typical Symptoms [Note (1)]	Analysis Type
Broken rotor bar	$Np \cdot S$ sidebands around 1x vibration, $Np \cdot S$ vibration $Np \cdot S$ sidebands around line frequency current, motor speed decrease	Motor current spectra, vibration spectra, and waveform
Nonuniform air gaps	2x line frequency vibration; $Np \cdot S$ sidebands around 1x vibration; $Np \cdot S$ vibration $Np \cdot S$ 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.

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 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/s) 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 $\pm$ 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 $\pm 5^\circ$, 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 section 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

(22) 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) anti-aliasing filters are not recommended for synchronously sampled waveforms. This preserves the phase coherency of all channels that are simultaneously and synchronously sampled. If anti-aliasing filters are used, methods shall be employed to preserve phase coherency.
- (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 analysis and display functions listed in the following paragraphs 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 1x and 2x 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 (1x) 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 maximum/minimum 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 section 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 10 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 coast-down 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 are 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 2 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 separately 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.

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.

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.

(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 1x amplitude and phase.

(i) Examine the 1x and 2x 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 μ m) in 5 min

(2) an amplitude increase or decrease of 1 mil (25 μ m)

(3) an increase in 2x amplitude of 50% when above 0.5 mils (15 μ m)

(4) an increase in 2x amplitude of 1 mil (25 μ m)

(5) a change in the phase of the 1x or 2x 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) 1x amplitude and phase trend plots

(5) 1x acceptance region plots

(6) 2x amplitude and phase trend plots

(7) 2x 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 1x rpm (rps) and 2x 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 1x and 2x 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 section 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 section 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 section 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 in./sec (2.5 mm/s). The alarm shall not exceed the manufacturer's recommended alert value or 0.3 in./sec (7.5 mm/s) 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/s). The alarm shall not exceed the manufacturer's recommended shutdown value or 0.6 in./sec (15 mm/s) 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 1x and 2x 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 are 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 deg to 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.

$$\text{accept} = \left(\frac{\text{max.} + \text{min.}}{2} \right) \pm 1.5(\text{max.} - \text{min.})$$

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, but 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:

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)

- (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) 1x and 2x 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 (section 4)
- (f) determining probable causes of the symptoms (section 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 E1934-99, Guide for Examining Electrical and Mechanical Equipment with Infrared Thermography, para. 3.5.

11.1.2 See Nonmandatory Appendix B of this Part 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 D6224, 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 D6224, 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 D6224, 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 D6224, Table 2, Turbine Type Oils (if other types of oil are in service, see ASTM D6224). Used oil that is to be left in service shall also have an oxidation stability test as specified in ASTM D6224, Table 2, Turbine Type Oils.

11.2.5 See Nonmandatory Appendix C of this Part for additional information.

11.3 Motor Current Signature Analysis

11.3.1 Motor current signature analysis shall include the measurement of the $N_p \times$ 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 of this Part 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 Part 12, Loose Part Monitoring in Water-Cooled Reactor Nuclear 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 of this Part 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 nonnuclear 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.

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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 r/s — Measurement and evaluation of vibration severity in situ
- ISO 7919-1, Mechanical vibration of non-reciprocating machines — Measurements on rotating shafts and evaluation — Part 1: General guidelines
- ISO 10816, Mechanical vibration — Evaluation of machine vibration by measurements of non-rotating parts
- Publisher: International Organization for Standardization (ISO), Central Secretariat, Chemin de Blandonnet 8, Case Postale 401, 1214 Vernier, Geneva, Switzerland (www.iso.org)

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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 D6224, 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 D6224, 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 D6224.

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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

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Part 25

Performance Testing of Emergency Core Cooling Systems in Light-Water Reactor Power Plants

Superseded by Part 28.

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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, U.S. Government Printing Office (GPO), 732 N. Capitol Street, NW, Washington, DC 20401 (www.gpo.gov)

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 Nonmandatory Appendix A of this Part 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.

Nonmandatory Appendix A of this Part 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 in a manner 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.

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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.

Part 28

Standard for Performance Testing of Systems in Water-Cooled Reactor Nuclear Power Plants

1 INTRODUCTION

1.1 Scope

This Part establishes the requirements for preservice and inservice testing to assess the operational readiness of certain safety-related systems and systems important to safety used in water-cooled reactor nuclear power plants.

The systems covered are those required to perform or support 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 assessing integrated system performance.

1.2 Exclusions

1.2.1 Use of this Part for a chosen system or systems within the Scope does not mandate application to all systems within the Scope.

1.2.2 This Part does not address nonsystem-level testing of components, instrumentation, and controls. Implementation of the applicable codes and standards that defines such testing is assumed. Verifying test acceptance criteria in accordance with this Part does not provide relief from meeting more limiting criteria associated with such codes and standards.

1.3 Owner's Responsibilities

1.3.1 Identify the system(s) to be tested in accordance with this Part. The identified systems could include any systems requiring a performance testing program based on the Owner's evaluation of regulatory issues or other Owner considerations.

1.3.2 Establish a test program for each system identified per para. 1.3.1 with the following elements:

(a) establish the boundaries for each system or portion of system subject to the requirements of this Part (see para. 4.1)

(b) identify performance requirements from licensing and design basis documentation (see para. 4.2)

(c) identify testable characteristics that represent performance requirements (see para. 4.3)

(d) establish test acceptance criteria for each characteristic (see para. 4.4)

(e) develop test procedures that include test acceptance criteria and test frequencies, and perform required testing, inspections, and engineering analysis (see para. 4.5)

(f) evaluate test data and implement corrective action as appropriate (see section 6)

(g) document and retain a test plan and test results (see section 7)

1.3.3 Use specific system test program requirements identified in section 5, as applicable.

1.3.4 Apply the appropriate quality assurance requirements to this program.

1.3.5 Review industry operating experience as an input to the development of this program (see Nonmandatory Appendix A of this Part).

1.3.6 Develop the 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. Define contingency actions, as appropriate, to manage plant risk during testing. Examples include increased oversight, use of dedicated plant operators, and termination criteria. If 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. 4.5 for additional guidance.

2 DEFINITIONS

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.

auxiliary feedwater system (AFWS): a system that provides inventory to the steam generators (PWR) or reactor (BWR) for heat removal when normal feedwater is unavailable.

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 product, or core support 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 design.

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.

least margin condition: the operating mode for the system where the characteristic being tested is closest to the operating limit.

maintenance: replacement of parts, adjustments, and similar actions that do not change the design (configuration and material) of an item.

modification: alteration in the design of a system, structure, or component.

open cooling water system: an open loop heat transfer system from supported structures, systems, and components directly to the ultimate heat sink.

preservice test: a test performed 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.

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

support system: any system that is necessary for the tested system to perform the intended function.

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

3 REFERENCES

(a) ASME OM-S/G-2000, Part 21, Inservice Testing of Heat Exchangers; Publisher: The American Society of Mechanical Engineers (ASME), Two Park Avenue, New York, NY 10016-5990 (www.asme.org)

(b) ASME Steam Tables, 5th Edition; Publisher: The American Society of Mechanical Engineers (ASME), Two Park Avenue, New York, NY 10016-5990 (www.asme.org)

(c) Flow Measurement Engineering Handbook. Miller, R. W. 2nd Edition. New York: McGraw-Hill, 1989; Publisher: McGraw-Hill Professional, Two Penn Plaza, New York, NY 10121

4 GENERAL TESTING REQUIREMENTS

This section provides generic direction for the first five elements of the test program outlined in para. 1.3.2. As applicable, specific system testing requirements are defined in section 5.

4.1 Establish System Test Boundaries

For system(s) identified per para. 1.3.1, establish the boundaries for system testing. Include within the test boundaries the portions of the system(s) that perform the functions described in para. 1.1. Appendices to this Part contain descriptions of test boundaries for certain systems.

Testing of support systems for the system(s) identified above, such as those providing electrical supply, heat rejection, chemical addition, engineered safety features actuation system (ESFAS) logic, or emergency core cooling system (ECCS) actuation logic, is not within the scope of this Part.

Consider the interaction of nonessential components that may affect system operation by isolation, leakage, or additional heat loads when establishing the test boundary. In some cases, the system test boundaries may include nonessential portions of the system or supporting systems that cannot be isolated. Testing of nonessential portions of the system is only required to the extent of verifying that there is no adverse impact on the performance of those portions of the system within the scope of this Part.

4.2 Identify System Performance Requirements

Identify performance requirements for the portions of the system 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, required

flow rates and distribution, system fluid temperature, and time to reach full flow after system actuation.

Identify performance requirements in a manner 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

- (a) nuclear steam supply system design specifications
- (b) architect-engineer specifications
- (c) safety analysis report (SAR)/updated safety analysis report (USAR)
- (d) safety evaluation report/supplemental safety evaluation reports
- (e) technical specifications
- (f) design basis documentation
- (g) vendor correspondence

When direct testing of each of the performance requirements is not practical, develop testable system characteristics in accordance with para. 4.3 that can be used to verify performance requirements.

4.3 Identify Testable Characteristics

(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. 4.2, includes

- (1) design calculations
- (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 verified 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 typical system operation are

- (1) system and branch line flows for each system alignment
- (2) total heat rejection capacity
- (3) system operating temperatures
- (4) maintaining system operation during system transients
- (5) operation in response to actuation signals 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.

4.3.1 Component Characteristics. Include component characteristics that affect system-level performance as system characteristics. An example is pump performance required to deliver design flow to the supported compo-

nents within a defined time interval after an initiating event.

4.3.2 Instrumentation and Control (I&C) Characteristics. Include instrumentation and control characteristics that affect system-level performance as system characteristics. These include indication and control of system parameters such as flow, pressure, level, temperature, and component status.

4.3.3 System Logic Characteristics. Include system logic characteristics as system characteristics. System logic is any permissive or interlock that actuates or aligns system components. System logic does not include ESFAS or ECCS actuation logic. Examples of system logic are

- (a) logic intended to start standby pumps on flow or pressure demand
- (b) logic for system realignment to accident mode from any nonsafety or secondary operating mode
- (c) logic for heat exchanger bypass or temperature control

4.4 Establish Acceptance Criteria

Establish acceptance criteria for each of the system characteristics derived in accordance with para. 4.3. Each system characteristic has analysis limits that are found in the plant design or licensing basis documentation and other source information described in paras. 4.2 and 4.3. 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 correlating accident analysis limits to practical test conditions. 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 Nonmandatory Appendix B, section B-4 of this Part for an example of this adjustment process for pump TDH versus flow. Refer to Nonmandatory Appendix C of this Part for guidance on test instrument accuracy. Use instruments that provide sufficient accuracy to ensure that the minimum design performance requirements of the system are being met, assuming maximum instrument error.

Review and revise as necessary all applicable acceptance criteria prior to the performance of each system functional test to ensure that changes in performance requirements caused by repairs or modifications are taken into account.

4.5 Develop Test Procedures and Perform Testing, Inspections, and Engineering Analysis

(a) Develop and approve test procedures to verify that acceptance criteria derived in accordance with para. 4.4 are met. Participation by organizations responsible for maintaining the design basis is required in developing test acceptance criteria and procedures. Use available operating experience (OE) information. Industry and government agency experience reports and databases give additional insights into system operation and testing. Nonmandatory Appendix A of this Part provides a summary of pertinent industry information.

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. Define contingency actions, as appropriate, to manage plant risk during testing. Portions of the system test may be performed at different plant operating modes in a manner consistent with managing plant risk.

Include specific requirements in the test procedure for data collection that support the acceptance criteria. Various means of data collection can be used, such as manual log, automatic data logger, or plant computer and must consider the need for historical retention to support data trending. Where appropriate, record as-found condition of tested parameters and document any reperformance of testing.

(b) This Part does not require simultaneous testing of all system components, subsystems, and support systems. A logical combination of several separate tests is acceptable; however, integrate the testing where practical. For example, the thermal and hydraulic performance of 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 the test results to correlate with 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. 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.

(c) 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 flow rate 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.

(d) This Part does not address nonsystem-level testing of components, instrumentation, and controls. Implementation of the applicable codes and standards that defines such testing is assumed. Verifying test acceptance criteria in accordance with this Part does not provide relief from meeting more limiting criteria associated with such codes and standards.

(e) 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.

4.5.1 Preservice Testing. Develop and conduct tests to measure system performance. The test results are used to determine that the system, component, I&C, and logic characteristics meet the associated acceptance criteria. The following subparagraphs provide requirements for preservice testing of some of the system characteristics described in para. 4.3:

(a) Conduct preservice testing under each set of conditions defined in the test plan to confirm the system's performance capability.

(b) Results of system startup tests may be used to satisfy the preservice testing requirements of this Part provided all other related requirements of this Part are met.

4.5.1.1 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. Perform the following prerequisites, as a minimum:

(a) electrical systems have been tested, including protective devices

(b) 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 or blowdown has verified system cleanliness

(e) temporary construction components, such as strainers, jumpers, etc. 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 installed, filled, and vented per design requirements

(h) system leak or pressure tests have been completed satisfactorily

(i) valves stroke when operated by control switches

(j) pump or compressor 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 are 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

(n) relief valves have been bench-tested to verify setpoints

4.5.1.2 Preservice Performance Test. Develop and conduct tests that address the following requirements, as applicable, for each operating mode:

(a) During pump or compressor operation, monitor the system for unacceptable noise, vibration, or cavitation.

(b) Verify that pipe and component supports are within allowable limits at normal system operating temperature.

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

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

(e) Verify automatic start of standby pumps and proper automatic alignment of valves and standby heat exchangers under a simulated emergency actuation signal.

(f) Verify that a single or multiple pump trips in a system utilizing 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).

(g) For the set throttle valve positions or restriction orifice sizes, verify that no pump combination will result in

(1) inadequate or excess flow conditions to each branch line or serviced component

(2) pump flow less than minimum required flow

Repositioning throttle valves or resizing flow orifices could significantly affect the flow balance or previous test results. Repperform the applicable flow testing when such modifications have been made. 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.

(h) Verify that system response during postulated transients, including loss of offsite power, is adequate to ensure that system operation is not compromised, including

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

(2) stroke times of boundary valves are within design requirements

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

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

(k) Verify proper operation of manually controlled components.

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

(m) Verify proper heat exchanger performance using methods described in ASME OM-S/G-2000 [see para. 3(a)].

(n) Test pump discharge flow path overall resistance and balanced branch line resistance for all flow paths. Establish system flows high enough to allow determination of flow path resistance. Refer to Nonmandatory Appendix B, sections B-5 through B-7 for guidance.

(o) Test the system characteristic of pump operation. For systems with multiple operating points, verify pump total dynamic head versus flow, using a five point (or greater) test, distributed between minimum and maximum expected flow rate. For systems with a narrow operating point range, select a suitable number of pump test points. 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, section B-4 for further guidance.

(p) 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 the acceptable operating range.

4.5.1.3 Preservice Test Interval. Perform preservice tests prior to plant fuel load. Evaluate the acceptability of the interval between completion of each of the prerequisite tests described in para. 4.5.1.1 and the related performance testing of para. 4.5.1.2. Evaluate the acceptability of the interval between completion of any preservice test and the time when a system has been declared in service and governed by inservice test interval.

Portions of the preservice testing may be deferred if required conditions for testing cannot be met until after plant fuel load. Base the 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.

4.5.2 Inservice Testing. Develop and conduct tests to measure system performance. The test results are used to determine that the system, component, I&C, and logic characteristics meet the associated acceptance criteria. The following subparagraphs provide requirements for inservice testing of some of the system characteristics described in para. 4.3:

(a) Conduct inservice testing under each set of conditions defined in the test plan to confirm the system's performance capability.

(b) Procedures or test programs established for other purposes (e.g., inservice testing, surveillance testing, maintenance rule) may be used to satisfy testing requirements of this Part to the extent that they meet the requirements of this Part.

(c) Testing of individual components or groups of components or measurement of individual parameters may be performed at different times, provided overall system performance is not affected by separation of the individual tests and provided that all required tests are performed within the specified test frequency.

4.5.2.1 Inservice Performance Test. Develop and conduct tests that address the following requirements, as applicable, for each operating mode:

(a) During pump or compressor operation, monitor the system for unacceptable noise, vibration, or cavitation.

(b) Verify that pipe and component supports are within allowable limits at normal system operating temperature.

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

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

(e) Verify automatic start of standby pumps and proper automatic alignment of valves and standby heat exchangers under a simulated emergency actuation signal.

(f) Verify that a single or multiple pump trips in a system utilizing 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).

(g) For the set throttle valve positions or restriction orifice sizes, verify that no pump combination will result in

(1) inadequate or excess flow conditions to each branch line or serviced component

(2) pump flow less than minimum required flow

Repositioning throttle valves or resizing flow orifices could significantly affect the flow balance or previous test results. Re-perform the applicable flow testing

when such modifications have been made. 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.

(h) Verify that system response during postulated transients, including loss of offsite power, is adequate to ensure that system operation is not compromised, including

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

(2) stroke times of boundary valves are within design requirements

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

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

(k) Verify proper operation of manually controlled components.

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

(m) Verify proper heat exchanger performance using methods described in ASME OM-S/G-2000 [see para. 3 (a)].

(n) Test pump discharge flow path overall resistance and balanced branch line resistance for all flow paths. Establish system flows high enough to allow determination of flow path resistance. Refer to Nonmandatory Appendix B, sections B-5 through B-7 for guidance.

(o) Test the system characteristic of pump operation. For systems with multiple operating points, verify pump total dynamic head versus flow, using a five point (or greater) test, distributed between minimum and maximum expected flow rate. For systems with a narrow operating point range, select a suitable number of pump test points. 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, section B-4 for further guidance.

(p) 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.

4.5.2.2 Inservice Test Interval

(a) Establish a 5-yr $\pm 25\%$ initial test interval for the inservice testing described in para. 4.5.2. After each test, establish the subsequent test interval based on evaluation of the test results, including trending, performed in accordance with section 6. If the test interval

is extended, the maximum allowable interval is 10 yr. Determine subsequent intervals for testing in accordance with this Part based on evaluation of the test results and other plant and industry information, such as equipment history records, test results, safety significance, and risk assessments. Include results of each evaluation in the test records.

(b) Test heat exchanger heat removal capability at the interval described in ASME OM-S/G-2000 [see para. 3(a)].

(c) Perform the applicable portions of para. 4.5.2 prior to returning the system to service following replacement, repair, maintenance, or modification to system components or systems that could affect the ability to meet system performance requirements identified per para. 4.2. Examples of such changes include

- (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 system 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.

5 SPECIFIC TESTING REQUIREMENTS

Use the information in this section to supplement sections 1 through 4 for the following specific systems. Then, refer to sections 6 and 7 for evaluation and documentation requirements.

5.1 Emergency Core Cooling Systems

Refer to Mandatory Appendix I of this Part for specific direction and information regarding testing of BWR emergency core cooling systems.

Refer to Mandatory Appendix II of this Part for specific direction and information regarding testing of PWR emergency core cooling systems.

5.2 Auxiliary or Emergency Feedwater Systems

Refer to Mandatory Appendix III of this Part for specific direction and information regarding testing of auxiliary feedwater systems.

5.3 Closed Cooling Water Systems

Refer to Mandatory Appendix IV of this Part for specific direction and information regarding testing of closed cooling water systems.

5.4 Emergency Service Water Systems

Refer to Mandatory Appendix V of this Part for specific direction and information regarding testing of emergency service water systems.

5.5 Instrument Air Systems

Refer to Mandatory Appendix VI of this Part for specific direction and information regarding testing of instrument air systems.

6 EVALUATE TEST DATA

6.1 Compare Data to Acceptance Criteria

Evaluate the test data against the acceptance criteria established in accordance with para. 4.4. If test results fail to meet acceptance criteria, take corrective action in accordance with either of the following:

- (a) Perform appropriate corrective actions on the nonconforming component or system, followed by retest.
- (b) Perform evaluations to disposition the affected components or nonconforming systems portion. Refine 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.

6.2 Trend Test Data

Compare as-found test data to corresponding prior as-left test data to identify significant trends in performance. Trends can be degradation, step changes, or anomalous test results. If analysis results identify adverse trends, investigate to determine the cause and take appropriate corrective action. Appropriate actions may include

- (a) restoration of the baseline condition
- (b) modification of the test interval or
- (c) modification of the acceptance criteria

6.3 Evaluate Test Interval

Evaluate the test data to project future system performance by considering

- (a) margin between acceptance criteria and system test results
- (b) system performance data trending
- (c) modification and maintenance history
- (d) internal and external system service conditions (for example, biofouling, corrosion, erosion, and wear)
- (e) frequency of operation

In addition, consider other plant and industry operating experience information that may influence a decision to change the test interval.

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.

7 DOCUMENTATION

For each system tested in accordance with this Part, 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, data evaluations, and corrective actions for the life of the plant.

7.1 System Test Plan

Document or reference within each system test plan the following, as a minimum:

(a) a brief description of the system or portion of the system subject to testing, including a description of the basis for the system test boundaries

(b) a description of the system performance requirements being tested and basis for selection

(c) a list of all system components that are required to function in support of the system performance requirement(s)

(d) a list of the testable characteristic(s) that each component is required to perform

(e) the basis for the selection of acceptance criteria and instrument accuracy requirements for each testable characteristic

(f) the detailed procedures or instructions for performance of the tests

(g) a detailed description of and justification for all assumptions, postulations, extrapolations, or calculations used to determine acceptance criteria or to correlate test data with postulated least margin conditions

(h) a detailed description of all exceptions to the requirements of this Part, including justification and alternate testing, engineering evaluation, or analysis

(i) other information as specified in this Part

7.2 Test Results and Corrective Actions

Document the test results and corrective actions that result from each execution of the system test plan.

Part 28, Mandatory Appendix I

Specific Testing Requirements of Emergency Core Cooling Systems in BWR Power Plants

I-1 INTRODUCTION

This Appendix, when used with this Part, requires development of a preservice and inservice testing program that provides reasonable assurance that emergency core cooling systems used in boiling water reactor (BWR) power plants perform in accordance with the system design basis over the life of the plant.

Establish this program using the requirements delineated in this Part and the system-specific requirements of this Appendix.

I-2 DEFINITIONS

condensate storage tank (CST): a storage tank containing water inventory for ECCS pump suction.

containment spray: a system to control containment pressure and temperature and to remove containment heat following accident conditions.

I-3 REFERENCE

Title 10, Code of Federal Regulations, Part 50, Section 50.46, Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors

Publisher: U.S. Government Printing Office (GPO), 732 N. Capitol Street, NW, Washington, DC 20401 (www.gpo.gov)

I-4 BWR ECCS TESTING REQUIREMENTS

This section provides specific direction for the first five elements of the test program outlined in para. 1.3.2 of this Part for BWR ECCS.

I-4.1 Establish System Testing Boundaries

Establish the BWR ECCS test boundaries using the following information in addition to the requirements of para. 4.1 of this Part. Include within the test boundaries all system functions described in para. 1.1 of this Part.

Establish the system test boundaries for all ECCS as defined in para. 1.1 of this Part, such as low-pressure injection, high-pressure injection, passive injection, pumped

recirculation, core spray, and automatic depressurization systems. Include within the test boundary 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.

Include within the test boundaries 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) containment air cooling
- (d) isolation condenser
- (e) reactor core isolation cooling
- (f) containment spray
- (g) suppression pool cooling
- (h) normal plant shutdown decay heat removal

For example, when establishing the test boundary, 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.

I-4.2 Identify System Performance Requirements

Identify system performance requirements for ECCS within the established test boundaries using the requirements of para. 4.2 of this Part. Specific ECCS examples beyond those of para. 4.2 of this Part include input parameters derived from safety analyses performed to meet the requirements of the reference in para. I-3, or equivalent, such as core delivered flow, ECCS fluid temperature, and time to reach full flow after ECCS actuation.

I-4.3 Identify Testable Characteristics That Represent Performance Requirements

Identify testable characteristics that can be used to confirm system performance requirements are met using the requirements of para. 4.3 of this Part. Specific examples of testable characteristics associated with typical ECCS operation, in addition to those in para. 4.3 of this Part, are pump developed head and system resistance that can be used to verify the performance requirement of core delivered flow.

I-4.3.1 Component Characteristics. Include ECCS component characteristics that affect system-level performance as system characteristics in accordance with the requirements of para. 4.3.1 of this Part.

I-4.3.2 Instrumentation and Control (I&C) Characteristics. Include ECCS instrumentation and control (I&C) characteristics that affect system-level performance as system characteristics in accordance with the requirements of para. 4.3.2 of this Part.

I-4.3.3 ECCS Logic Characteristics. Include ECCS logic characteristics that affect system-level performance as system characteristics in accordance with the requirements of para. 4.3.3 of this Part. Examples of ECCS logic are

- (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 CST to the containment suppression pool
- (e) interlocks, such as the pressure permissive logic for injection valves on low-pressure injection systems
- (f) logic for ECCS injection path selection
- (g) logic for system realignment to accident mode from any nonsafety or secondary operating mode

I-4.3.4 System Characteristics. Identify ECCS system characteristics for the high-pressure injection, depressurization, low-pressure injection, and long term decay heat removal modes. The following paragraphs provide some examples of system characteristics for the four operating modes. These examples are not to be considered all-inclusive.

I-4.3.4.1 High-Pressure Injection Mode Characteristics. System characteristics associated with the high-pressure injection mode are

- (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 do not trip 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

I-4.3.4.2 Depressurization Mode Characteristics. System characteristics associated with the depressurization mode are

- (a) blowdown mass flow rate
- (b) initiation logic operation

I-4.3.4.3 Low-Pressure Injection Mode Characteristics. System characteristics associated with the low-pressure injection mode are

- (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 do not trip 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.

I-4.3.4.4 Long-Term Decay Heat Removal Mode Characteristics. System characteristics associated with long-term post-accident heat removal are

- (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 do not trip 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

I-4.4 Establish Characteristic Acceptance Criteria

Establish acceptance criteria for each system characteristic in accordance with the requirements of para. 4.4 of this Part.

I-4.5 Develop Test Procedures and Perform Testing, Inspections, and Engineering Analysis

Develop and approve test procedures in accordance with para. 4.5 of this Part to verify acceptance criteria derived in accordance with para. 1.4.4 of this Part are met.

I-4.5.1 Preservice Testing. Develop and conduct tests to measure system performance in accordance with the requirements of para. 4.5.1 of this Part.

I-4.5.1.1 Preservice Test Prerequisites. Identify prerequisites to preservice testing in accordance with the requirements of para. 4.5.1.1 of this Part.

I-4.5.1.2 Preservice Performance Test. Develop and conduct tests to measure system performance in accordance with the requirements of para. 4.5.1.2 of this Part. There are no specific requirements applying to preservice testing that are beyond those stipulated in this Appendix for inservice testing.

I-4.5.1.3 Preservice Test Interval. Perform preservice tests at an interval in accordance with para. 4.5.1.3 of this Part.

I-4.5.2 Inservice Testing. Develop and conduct tests to measure ECCS system performance in accordance with the requirements of para. 4.5.2 of this Part. The following paragraphs provide requirements for inservice testing of some of the system characteristics described in paras. I-4.3.4.1, I-4.3.4.2, I-4.3.4.3, and I-4.3.4.4.

I-4.5.2.1 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 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. I-4.5.2.5 for specific test frequency exceptions for testing with simultaneous flow from interacting divisions to the reactor vessel.

(b) 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. I-4.5.2.5 for specific test frequency exceptions for vortex formation testing.

I-4.5.2.2 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. I-4.5.2.5 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.

I-4.5.2.3 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 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. I-4.5.2.5 for specific test frequency exceptions for testing with simultaneous flow from interacting divisions to the reactor vessel.

(b) 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. I-4.5.2.5 for specific test frequency exceptions for vortex formation testing.

I-4.5.2.4 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 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. I-4.5.2.5 for specific test frequency exceptions for vortex formation testing.

(b) Test heat exchanger ECCS decay heat removal capability.

I-4.5.2.5 Inservice Test Interval. Perform inservice tests at an interval in accordance with para. 4.5.2.2 of this Part. Allowable exceptions to para. 4.5.2.2 of this Part are as follows:

(a) Conduct the integrated ECCS test with simultaneous flow from all interacting divisions [I-4.5.2.1(a) and I-4.5.2.3(a)] to the reactor vessel at a 10-yr +25% time interval.

(b) Suction vortex formation testing [I-4.5.2.1(b), I-4.5.2.3(b), and I-4.5.2.4(a)] need only be performed following any modification that affects the corresponding performance requirements of para. I-4.2. This exception is

allowed provided there is objective evidence that the requirements of these paragraphs have been met at least once.

(c) Testing of the ADS valves in I-4.5.2.2(a) need only be performed following any modification that affects the corresponding performance requirements of para. I-4.2, provided there is objective evidence that the requirements of this paragraph have been met at least once.

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Part 28, Mandatory Appendix II

Specific Testing Requirements of Emergency Core Cooling Systems in PWR Power Plants

II-1 INTRODUCTION

This Appendix, when used with this Part, requires development of a preservice and inservice testing program that provides reasonable assurance that emergency core cooling systems used in pressurized water reactor (PWR) power plants perform in accordance with the system design basis over the life of the plant.

Establish this program using the requirements delineated in this Part and the system-specific requirements of this Appendix.

II-2 DEFINITIONS

borated water supply tank (BWST): a storage tank containing borated water inventory for PWR ECCS pump suction during the injection phase.

containment spray: a system to control containment pressure and temperature and to remove containment heat following accident conditions.

II-3 REFERENCES

(a) Title 10, Code of Federal Regulations, Part 50, Section 50.46, Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors
Publisher: U.S. Government Printing Office (GPO), 732 N. Capitol Street, NW, Washington, DC 20401 (www.gpo.gov)

(b) 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
Publisher: U.S. Nuclear Regulatory Commission (NRC), One White Flint North, 11555 Rockville Pike, Rockville, MD 20852-2738 (www.nrc.gov)

II-4 PWR ECCS TESTING REQUIREMENTS

This section provides specific direction for the first five elements of the test program outlined in para. 1.3.2 of this Part for PWR ECCS.

II-4.1 Establish System Testing Boundaries

Establish the PWR ECCS test boundaries using the following information in addition to the requirements of para. 4.1 of this Part. Include within the test boundaries all system functions described in para. 1.1 of this Part.

Establish the system test boundaries for all ECCS as defined in section II-2, such as low pressure injection, high pressure injection, passive injection, pumped recirculation, and automatic depressurization systems. Include within the test boundary 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.

Include within the test boundaries 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
- (d) containment air cooling
- (e) containment spray
- (f) normal plant shutdown decay heat removal

For example, when establishing the test boundary, 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.

II-4.2 Identify System Performance Requirements

Identify system performance requirements for ECCS within the established test boundaries using the requirements of para. 4.2 of this Part. Specific ECCS examples beyond those of para. 4.2 of this Part, include input parameters derived from safety analyses performed to meet the requirements of the reference in para. II-3(a), or equivalent, such as core delivered flow, ECCS fluid temperature, and time to reach full flow after ECCS actuation.

II-4.3 Identify Testable Characteristics That Represent Performance Requirements

Identify testable characteristics that can be used to confirm system performance requirements are met using the requirements of para. 4.3 of this Part. Specific examples of testable characteristics associated with typical ECCS operation, in addition to those in para. 4.3 of this Part, are pump developed head and system resistance that can be used to verify the performance requirement of core delivered flow.

II-4.3.1 Component Characteristics. Include ECCS component characteristics that affect system-level performance as system characteristics in accordance with the requirements of para. 4.3.1 of this Part.

II-4.3.2 Instrumentation and Control (I&C) Characteristics. Include ECCS Instrumentation and Control (I&C) characteristics that affect system-level performance as system characteristics in accordance with the requirements of para. 4.3.2 of this Part.

II-4.3.3 ECCS Logic Characteristics. Include ECCS logic characteristics that affect system-level performance as system characteristics in accordance with the requirements of para. 4.3.3 of this Part. Examples of ECCS logic are

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

II-4.3.4 System Characteristics. Identify ECCS system characteristics for the passive injection, pumped injection, and pumped recirculation ECCS operating modes. The following paragraphs provide some examples of system characteristics for the three operating modes. These examples are not to be considered all-inclusive.

II-4.3.4.1 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.

II-4.3.4.2 Pumped Injection Mode Characteristics.

System characteristics associated with the pumped injection mode are

- (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 do not trip 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

II-4.3.4.3 Pumped Recirculation Mode Characteristics. System characteristics associated with the pumped recirculation mode are

- (a) NPSH available is greater than that required at accident conditions (such as temperature, pressure, flow, and blockage) as discussed in the reference in para. II-3(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. II-4.3.4.2
- (c) operation of each pump in all design operating modes not addressed in para. II-4.3.4.2, including pump drivers will not trip under worst-case flow conditions
- (d) 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
- (e) heat removal from ECCS heat exchangers
- (f) transfer of pump suction from the BWST to the containment sump

II-4.4 Establish Characteristic Acceptance Criteria

Establish acceptance criteria for each system characteristic in accordance with the requirements of para. 4.4 of this Part.

II-4.5 Develop Test Procedures and Perform Testing, Inspections, and Engineering Analysis

Develop and approve test procedures in accordance with para. 4.5 of this Part to verify acceptance criteria derived in accordance with para. II-4.4 are met.

II-4.5.1 Preservice Testing. Develop and conduct tests to measure system performance in accordance with the requirements of para. 4.5.1 of this Part.

II-4.5.1.1 Preservice Test Prerequisites. Identify prerequisites to preservice testing in accordance with the requirements of para. 4.5.1.1 of this Part.

II-4.5.1.2 Preservice Performance Test. Develop and conduct tests to measure system performance in accordance with the requirements of para. 4.5.1.2 of this Part. There are no specific requirements applicable to preservice testing that are beyond those stipulated in this Appendix for inservice testing.

II-4.5.1.3 Preservice Test Interval. Perform preservice tests at an interval in accordance with para. 4.5.1.3 of this Part.

II-4.5.2 Inservice Testing. Develop and conduct tests to measure ECCS system performance in accordance with the requirements of para. 4.5.2 of this Part. The following paragraphs provide requirements for inservice testing of some of the system characteristics described in paras. II-4.3.4.1, II-4.3.4.2, and II-4.3.4.3.

II-4.5.2.1 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. II-4.5.2.4 of this Appendix for specific test frequency requirements and exceptions. See Nonmandatory Appendix B, section B-2 of this Part for technical guidance.

II-4.5.2.2 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 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. II-4.5.2.4 for specific test frequency requirements and exceptions for testing with simultaneous flow from interacting trains to the RCS.

(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. 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. II-4.5.2.4(b) for specific test frequency exceptions for

vortex formation testing. Refer to Nonmandatory Appendix A of this Part for additional information.

II-4.5.2.3 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.

(b) 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. II-4.5.2.4 for specific test frequency exceptions.

(c) 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.

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.

NOTE: When testing pump discharge flow path overall resistance and balanced branch line resistance per para. 4.5.2.1(n) of this Part, pump suction may be aligned from alternate sources with appropriate analytical justification.

II-4.5.2.4 Inservice Test Interval. Perform inservice tests at an interval in accordance with para. 4.5.2.2 of this Part. Allowable exceptions to para. 4.5.2.2 of this Part are as follows:

(a) Conduct the integrated ECCS test with simultaneous flow from all trains [para. II-4.5.2.2(a)] to the reactor vessel at a 10-yr +25% time interval.

(b) ECCS accumulator testing (para. II-4.5.2.1), containment sump testing [para. II-4.5.2.3(a)], and suction vortex formation testing [paras. II-4.5.2.2(b) and II-4.5.2.3(a)] need only be performed following any modification

that affects the corresponding performance requirements of para. II-4.2. This exception is allowed provided there is objective evidence that the requirements of these paragraphs have been met at least once.

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Part 28, Mandatory Appendix III

Specific Testing Requirements of Auxiliary or Emergency Feedwater Systems in Water-Cooled Reactor Nuclear Power Plants

III-1 INTRODUCTION

This Appendix, when used with this Part, requires development of a preservice and inservice testing program that provides reasonable assurance that auxiliary feedwater systems perform in accordance with the system design basis over the life of the plant.

Establish this program using the requirements delineated in this Part and the system-specific requirements of this Appendix.

III-2 DEFINITION

condensate storage tank (CST): a storage tank containing water inventory for AFWS pump suction.

III-3 REFERENCES

None.

III-4 AUXILIARY FEEDWATER SYSTEM TESTING REQUIREMENTS

This section provides specific direction for the first five elements of the test program outlined in para. 1.3.2 of this Part for AFWS.

III-4.1 Establish System Testing Boundaries

Establish the AFWS test boundaries using the following information in addition to the requirements of para. 4.1 of this Part. Include within the test boundaries all system functions described in para. 1.1 of this Part. Include within the test boundary all equipment required to perform the AFWS function of delivering water from the source to the steam generators (PWR) or reactor vessel (BWR).

For example, include within the system boundary all components (i.e., pumps, valves, piping, instrumentation) in the flow paths between the CST and the steam generators (PWR) or reactor (BWR).

III-4.2 Identify System Performance Requirements

Identify system performance requirements for AFWS within the established test boundaries using the requirements of para. 4.2 of this Part. Specific AFWS examples beyond those of para. 4.2 of this Part include delivery of minimum flow to the steam generators (PWR) or reactor (BWR) and time to reach full flow after AFWS actuation.

III-4.3 Identify Testable Characteristics That Represent Performance Requirements

Identify testable characteristics that can be used to confirm system performance requirements are met using the requirements of para. 4.3 of this Part. Specific examples of testable characteristics associated with typical AFWS operation, in addition to those in para. 4.3 of this Part, are pump developed head and system resistance that can be used to verify the performance requirement of steam generator delivered flow (PWR).

III-4.3.1 Component Characteristics. Include AFWS component characteristics that affect system-level performance as system characteristics in accordance with the requirements of para. 4.3.1 of this Part. Specific examples of component characteristics associated with AFWS components are

- (a) net positive suction head (NPSH) for pump performance under system conditions with the least NPSH margin
- (b) pump total dynamic head (TDH) versus flow
- (c) pump response time (time to reach rated flow)
- (d) pump drivers do not trip under flow conditions with the least margin to trip
- (e) pump minimum flow path under individual and combined pump operation
- (f) pump performance under parallel pump operation

III-4.3.2 Instrumentation and Control (I&C) Characteristics. Include AFWS instrumentation and control (I&C) characteristics that affect system-level performance as system characteristics in accordance with the requirements of para. 4.3.2 of this Part.

III-4.3.3 AFWS Logic Characteristics. Include AFWS logic characteristics that affect system-level performance as system characteristics in accordance with the requirements of para. 4.3.3 of this Part. Examples of AFWS logic are

- (a) logic that causes AFWS components to actuate via an ESFAS, anticipated transients without scram (ATWS) mitigation circuitry, loss of offsite power and low steam generator level signal (PWR), or low reactor level (BWR)
- (b) logic that causes AFWS components to actuate when all feedwater pumps trip

III-4.4 Establish Characteristic Acceptance Criteria

Establish acceptance criteria for each system characteristic in accordance with the requirements of para 4.4 of this Part.

III-4.5 Develop Test Procedures and Perform Testing, Inspections, and Engineering Analysis

Develop and approve test procedures in accordance with para. 4.5 of this Part to verify that acceptance criteria derived in accordance with the requirements of para. III-4.4 are met.

III-4.5.1 Preservice Testing. Develop and conduct tests to measure system performance in accordance with the requirements of para. 4.5.1 of this Part.

III-4.5.1.1 Preservice Test Prerequisites. Identify prerequisites to preservice testing in accordance with the requirements of para. 4.5.1.1 of this Part.

III-4.5.1.2 Preservice Performance Test. Develop and conduct tests to measure system performance in accordance with the requirements of para. 4.5.1.2 of this Part. In addition, address the following AFWS-specific requirements:

(a) Verify that the AFWS 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 AFWS pumps are operating. Verify that system flow balancing requirements are maintained [e.g., flow to multiple steam generators (PWR)].

(b) Operate AFWS in each required operating alignment and pump combination as allowed by plant design. Test each AFWS train as close as practical to

design conditions; however, all back pressure conditions are not required to be simulated simultaneously. Verify that the required flow is achieved on each branch line of AFWS.

Test for adequate NPSH and acceptable pressure drops in suction lines and valves from the CST to the pump suction under maximum flow conditions. These tests should include transfer of pump suction between the CST and any alternate inventory source where applicable. Verify that vortex formation is minimized. Since these tests are associated with the suction flow path only, use full flow test return paths if available.

III-4.5.1.3 Preservice Test Interval. Perform preservice tests at an interval in accordance with para. 4.5.1.3 of this Part.

III-4.5.2 Inservice Testing. Develop and conduct tests to measure AFWS performance in accordance with the requirements of para. 4.5.2 of this Part. The following paragraphs provide requirements for inservice testing of some of the system characteristics described in para. III-4.3.

III-4.5.2.1 Inservice Performance Test. Develop and conduct tests to measure system performance in accordance with the requirements of para. 4.5.2.1 of this Part and para. III-4.3. In addition, address the following AFWS-specific requirements:

(a) Verify that the AFWS 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 AFWS pumps are operating. Verify system flow balancing requirements are maintained.

(b) Operate AFWS in the accident alignment with each required cooling water branch line and pump combination as allowed by plant design. Test each AFWS train as close as practical to design conditions. Verify that the required flow is achieved on each branch line of AFWS.

III-4.5.2.2 Inservice Test Interval. Perform inservice tests at an interval in accordance with para. 4.5.2.2 of this Part. An allowable exception to para. 4.5.2.2 of this Part is that suction vortex formation testing (para. III-4.5.1.2) need only be performed following any modification that affects the corresponding performance requirements of para. III-4.2. This exception is allowed provided there is objective evidence that the requirements of these paragraphs have been met at least once.

Part 28, Mandatory Appendix IV

Specific Testing Requirements of Closed Cooling Water Systems in Water-Cooled Reactor Nuclear Power Plants

IV-1 INTRODUCTION

This Appendix, when used with this Part, requires development of a preservice and inservice testing program that provides reasonable assurance that closed cooling water systems perform in accordance with the system design basis over the life of the plant.

Establish this program using the requirements delineated in this Part and the system-specific requirements of this Appendix.

IV-2 DEFINITIONS

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

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

IV-3 CLOSED COOLING WATER SYSTEM TESTING REQUIREMENTS

This section provides specific direction for the first five elements of the test program outlined in para. 1.3.2 of this Part for closed cooling water systems.

IV-3.1 Establish System Test Boundaries

Establish the CCWS test boundaries using the following information in addition to the requirements of para. 4.1 of this Part. Include within the test boundaries all CCWS functions described in para. 1.1 of this Part. Include within the test boundary 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.

- (a) Typical functions include
- (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 branch lines

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

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

- (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

IV-3.2 Identify System Performance Requirements

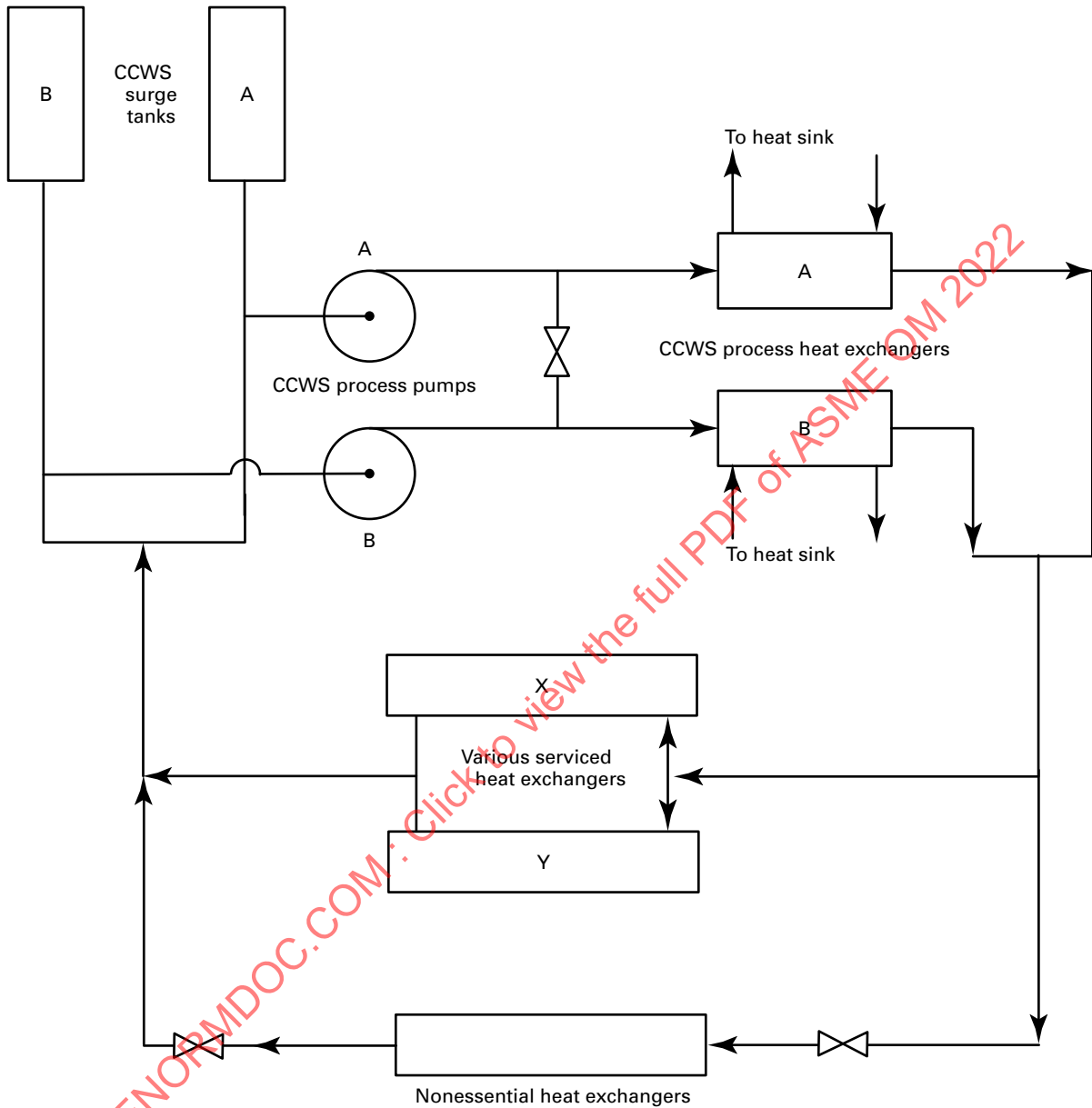
Identify system performance requirements for CCWS within the established test boundaries using the requirements of para. 4.2 of this Part. Specific CCWS examples beyond those of para. 4.2 of this Part include required heat removal rates from serviced loads, required flow rates to serviced loads, heat exchanger performance, surge tank makeup, and system fluid losses.

IV-3.3 Identify Testable Characteristics That Represent Performance Requirements

Identify testable characteristics that can be used to confirm system performance requirements are met using the requirements of para. 4.3 of this Part. Specific examples of testable characteristics associated with typical CCWS operation, in addition to those in para. 4.3 of this Part, are

- (a) system operating pressures at component elevations where conditions could approach saturation
- (b) maintaining system operation during system transients, such as pump trip in parallel pump operation
- (c) pressure differential between the CCWS and the heat sink system is in the appropriate direction

Figure IV-1
CCWS Typical Flow Diagram



IV-3.3.1 Component Characteristics. Include component characteristics that affect system-level performance as system characteristics in accordance with the requirements of para. 4.3.1 of this Part. In addition to the examples described in para. 4.3.1 of this Part, additional examples of CCWS 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

(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

IV-3.3.2 Instrumentation and Control Characteristics. Include CCWS instrumentation and control characteristics that affect system-level performance as system characteristics in accordance with the requirements of para. 4.3.2 of this Part.

IV-3.3.3 System Logic Characteristics. Include CCWS logic characteristics as system characteristics in accordance with the requirements of para. 4.3.3 of this Part. Specific examples of CCWS logic characteristics are

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

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

(c) logic associated with control of manually operated components

IV-3.4 Establish Acceptance Criteria for Testable Characteristics

Establish acceptance criteria for each system characteristic in accordance with the requirements of para. 4.4 of this Part.

IV-3.5 Develop Test Procedures and Perform Testing, Inspections, and Engineering Analysis

Develop and approve test procedures in accordance with para. 4.5 of this Part to verify acceptance criteria derived in accordance with the requirements of para. IV-3.4 are met.

IV-3.5.1 Preservice Testing. Develop and conduct tests to measure system performance in accordance with the requirements of para. 4.5.1 of this Part. Specific requirements for CCWS, in addition to those in para. 4.5.1 of this Part, are provided below.

IV-3.5.1.1 Preservice Test Prerequisites. Identify prerequisites to preservice testing in accordance with the requirements of para. 4.5.1.1 of this Part.

IV-3.5.1.2 Preservice Performance Test. Develop and conduct tests to measure system performance in accordance with the requirements of para. 4.5.1.2 of this Part. In addition, address the following CCWS-specific requirements.

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. Verify that the required flow is achieved on each branch line or serviced component of CCWS.

Address the following requirements for each applicable operating mode:

(a) Verify that automatic surge tank makeup functions. Demonstrate manual makeup where credited.

(b) Verify that level instrumentation and alarms function properly to allow appropriate response to a loss of surge tank level.

Perform final system flow balancing with available or simulated heat loads. Heat loads not available during this test should be estimated and accommodated 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 the reference in para. 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 re-perform the appropriate tests of this Part or Part 21.

IV-3.5.1.3 Preservice Test Interval. Perform preservice tests at an interval in accordance with para. 4.5.1.3 of this Part.

IV-3.5.2 Inservice Testing. Develop and conduct tests to measure system performance in accordance with the requirements of para. 4.5.2 of this Part.

IV-3.5.2.1 Inservice Performance Test. Develop and conduct tests to measure system performance in accordance with the requirements of para. 4.5.2.1 of this Part. In addition, address the following CCWS-specific requirements.

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 line 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 line or serviced component of CCWS.

Verify that automatic surge tank makeup functions for each applicable operating mode. Demonstrate manual makeup where credited. Verify that level instrumentation and alarms function properly to allow appropriate response to a loss of surge tank level.

IV-3.5.2.2 Inservice Test Interval. Perform inservice tests at intervals in accordance with para. 4.5.2.2 of this Part.

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Part 28, Mandatory Appendix V

Specific Testing Requirements of Emergency Service Water Systems in Water-Cooled Reactor Nuclear Power Plants (Open Cooling Water Systems)

V-1 INTRODUCTION

This Appendix, when used with this Part, requires development of a preservice and inservice testing program that provides reasonable assurance that emergency service water systems (ESWS) perform in accordance with the system design basis over the life of the plant.

Establish this program using the requirements delineated in this Part and the system-specific requirements of this Appendix.

V-2 DEFINITIONS

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

serviced heat exchanger: a heat exchanger in a supported system that rejects heat to the open cooling water system.

V-3 EMERGENCY SERVICE WATER SYSTEM TEST REQUIREMENTS

This section provides specific direction for the first five elements of the test program outlined in para. 1.3.2 of this Part for ESWS.

V-4 ESTABLISH SYSTEM TEST BOUNDARIES

V-4.1 General

Establish the ESWS test boundaries using the following information in addition to the requirements of para. 4.1 of this Part. Include within the test boundaries all ESWS functions described in para. 1.1 of this Part. Include within the test boundary all equipment required to perform the ESWS functions of transferring heat from the supported structures, systems, and components to the ultimate heat sink. This test boundary includes the serviced heat exchangers for the heat sources for ESWS and includes the ultimate heat sink.

- (a) *Typical Functions*. Typical functions include
- (1) closed cooling water system heat removal
 - (2) decay heat removal
 - (3) containment heat removal

(4) pump and pump driver cooling

(5) diesel generator jacket water cooling

(b) *Typical ESWS*. Figure IV-1 in Mandatory Appendix IV of this Part shows a simplified ESWS flow diagram and identifies some major components. Components of the typical ESWS may include

(1) ESWS process pumps

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

(3) motor controllers, controls, and protective relays

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

(5) serviced heat exchangers

(6) the ultimate heat sink, including heat transfer components such as cooling towers and spray ponds

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

(8) water quality monitoring and control equipment

(9) filters and trash screens

(10) alternate suction sources

V-4.2 Identify System Performance Requirements

Identify system performance requirements for ESWS within the established test boundaries using the requirements of para. 4.2 of this Part. Specific ESWS examples beyond those of para. 4.2 of this Part include required heat removal rates from serviced loads, required flow rates to serviced loads, and heat exchanger performance in addition to heat absorption and rejection requirements of the ultimate heat sink.

V-4.3 Identify Testable Characteristics That Represent Performance Requirements

Identify testable characteristics that can be used to confirm that system performance requirements are met using the requirements of para. 4.3 of this Part. Specific examples of testable characteristics associated with typical ESWS operation, in addition to those in para. 4.3 of this Part, are

(a) system operating pressures at component elevations where conditions could approach saturation

(b) maintaining system operation during system transients, such as pump trip in parallel pump operation

(c) pressure differential between the ESWS and the heat source systems in the appropriate direction

V-4.3.1 Component Characteristics. Include component characteristics that affect system-level performance as system characteristics in accordance with the requirements of para. 4.3.1 of this Part. In addition to the examples described in para. 4.3.1 of this Part, additional examples of an ESWS system characteristics are flow for serviced ESWS heat exchangers, and heat removal for ESWS process heat exchangers.

System characteristics associated with ESWS components are

(a) *ESWS 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) *Ultimate Heat Sink*

(1) amount of heat required to be transferred

(2) ESWS inlet temperature

(3) available volume

V-4.3.2 Instrumentation and Control Characteristics. Include ESWS instrumentation and control characteristics that affect system-level performance as system characteristics in accordance with the requirements of para. 4.3.2 of this Part.

V-4.3.3 System Logic Characteristics. Include ESWS logic characteristics as system characteristics in accordance with the requirements of para. 4.3.3 of this Part. Specific ESWS examples of logic are

(a) logic that causes ESWS components to actuate via an ESFAS, ECCS actuation signal, or blackout signal

(b) logic that causes ESWS pumps to start on CCWS start signal

(c) logic associated with control of manually operated components

V-4.4 Establish Acceptance Criteria for Testable Characteristics

Establish acceptance criteria for each system characteristic in accordance with the requirements of para. 4.4 of this Part.

V-4.5 Develop Test Procedures and Perform Testing, Inspections, and Engineering Analysis

Develop and approve test procedures in accordance with para. 4.5 of this Part to verify that acceptance criteria derived in accordance with the requirements of para. V-4.4 of this Part are met.

V-4.5.1 Preservice Testing. Develop and conduct tests to measure system performance in accordance with the requirements of para. 4.5.1 of this Part.

V-4.5.1.1 Preservice Test Prerequisites. Identify prerequisites to preservice testing in accordance with the requirements of para. 4.5.1.1 of this Part.

V-4.5.1.2 Preservice Performance Test. Develop and conduct tests to measure system performance in accordance with the requirements of para. 4.5.1.2 of this Part. In addition, address the following ESWS-specific requirements.

Verify that the ESWS 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 ESWS pumps are operating. Verify system flow balancing for heat transfer requirements is maintained.

Operate ESWS in each required cooling water alignment and pump combination as allowed by plant design. Test each ESWS 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 line or serviced component of ESWS.

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 ultimate heat sink heat removal capability. The process described in paras. V-4.2, V-4.3, and V-4.4 will require review of applicable design and analytical information to determine which assumptions require verification by testing to ensure their validity. The resulting testing requirements will vary, depending on the specific design. Note that para. 4.5(b) of this Part allows appropriate use of analysis to account for differences between least margin and test conditions. Perform testing to validate testable characteristics of heat rejection systems/components for plants that rely upon man-made or mechanical devices to reject heat to the environment, such as cooling towers, spray ponds, constructed lakes, or dammed lakes.

V-4.5.1.3 Preservice Test Interval. Perform preservice tests at an interval in accordance with para. 4.5.1.3 of this Part.

V-4.5.2 Inservice Testing. Develop and conduct tests to measure system performance characteristic in accordance with the requirements of para. 4.5.2 of this Part.

V-4.5.2.1 Inservice Performance Test. Develop and conduct tests to measure system performance in accordance with the requirements of para. 4.5.2.1 of this Part. In addition, address the following ESWS-specific requirements.

Verify that the ESWS 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 ESWS pumps are operating. Verify that system flow balancing for heat transfer requirements is maintained.

Operate ESWS in the accident alignment with each required cooling water branch line and pump combination as allowed by plant design. Test each ESWS 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 line or serviced component of ESWS.

V-4.5.2.2 Inservice Test Interval. Perform inservice tests at intervals in accordance with para. 4.5.2.2 of this Part. An allowable exception to para. 4.5.2.2 of this Part is that verification of ultimate heat sink capability need only be performed following any modification that affects the corresponding performance requirements of para. V-4.2. This exception is allowed provided there is objective evidence that the requirements of para. V-4.2 have been met at least once.

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Part 28, Mandatory Appendix VI

Specific Testing Requirements of Instrument Air Systems in Water-Cooled Reactor Nuclear Power Plants

VI-1 INTRODUCTION

This Appendix, when used with this Part, requires development of a preservice and inservice testing program that provides reasonable assurance that instrument air (IA) systems perform in accordance with the system design basis over the life of the plant.

Establish this program using the requirements delineated in this Part and the system-specific requirements of this Appendix.

VI-2 DEFINITIONS

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.

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.

dew point: temperature at which water vapor begins to condense into liquid.

distribution network: piping and components that supply compressed air to end-use devices.

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.

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.

special service accumulator: backup air reservoir located near equipment, used to supply compressed air upon loss of the normal source.

VI-3 INSTRUMENT AIR SYSTEM TESTING REQUIREMENTS

This section provides specific direction for the first five elements of the test program outlined in para. 1.3.2 of this Part for IA systems.

VI-3.1 Establish System Testing Boundaries

Establish the IA test boundaries using the following information in addition to the requirements of para. 4.1 of this Part. Include within the test boundaries all system functions described in para. 1.1 of this Part.

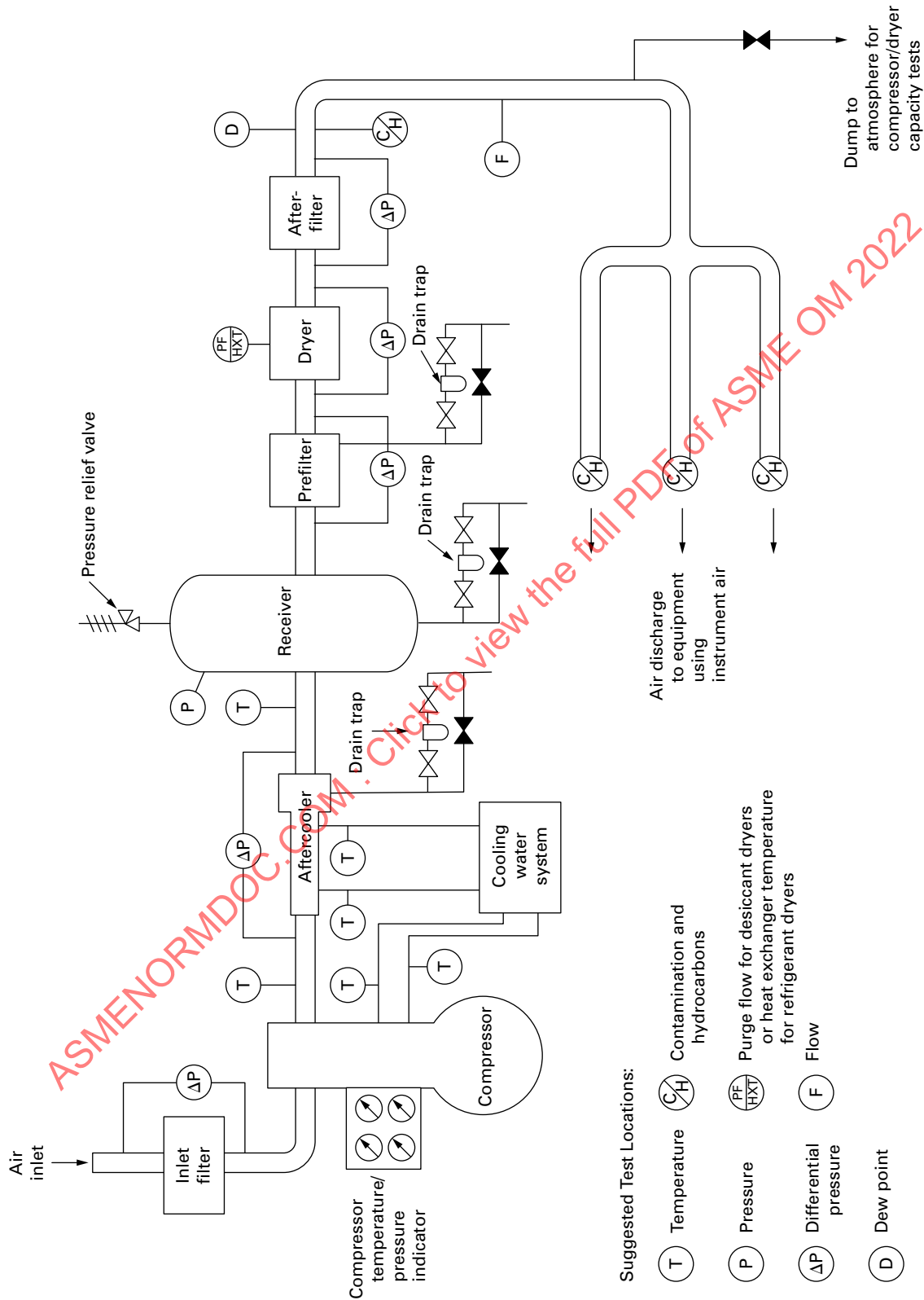
For the purposes of this Appendix, the IA system extends from the compressor inlet air filter to, but not including, the end-use device or system of devices (e.g., instrument, equipment prime mover).

Figure VI-1 shows a typical flow diagram of an IA system and identifies major components. For this Appendix, an IA system is treated as three subsystems as follows:

(a) *Compressor and Receiver*. 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.

(b) *Dryer and Filters*. Compressed air is processed by the dryer and filter subsystem of the IA 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

Figure VI-1
Typical Instrument Air System



that removes water vapor; and an afterfilter that removes particulates. The dryer and filter system supplies clean, dry air to the distribution network.

(c) *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.

VI-3.2 Identify System Performance Requirements

Identify system performance requirements for IA systems within the established test boundaries using the requirements of para. 4.2 of this Part. Specific IA system examples beyond those of para. 4.2 of this Part, include the following:

(a) *Compressor and Receiver.* The compressor and receiver subsystem supplies pressurized, cooled, wet air to the dryer and filter subsystem at the required demand rate and pressure.

(b) *Dryer and Filters.* Compressed air is processed by the dryer and filter subsystem to supply clean, dry air to the distribution network at the required dew point, cleanliness, demand rate, and pressure.

(c) *Distribution Network.* The distribution network supplies compressed air to end-use devices at required capacity and pressure.

VI-3.3 Identify Testable Characteristics That Represent Performance Requirements

Identify testable characteristics that can be used to confirm system performance requirements are met using the requirements of para. 4.3 of this Part. Specific examples of testable characteristics associated with typical IA system operation, in addition to those in para. 4.3 of this Part, are dew point, cleanliness, demand rate, and pressure that can be used to verify the performance requirement of the end use equipment.

VI-3.3.1 Component Characteristics. Include IA system component characteristics that affect system-level performance as system characteristics in accordance with the requirements of para. 4.3.1 of this Part. Specific examples of component characteristics are

- (a) *Compressor and Receiver Subsystem*
- (1) inlet filter dP
 - (2) load and unload pressure setpoint
 - (3) after cooler and compressor outlet temperature
 - (4) compressor output flow, by means of a flow rate meter installed downstream of the receiver
 - (5) pressure drop across the compressor inlet filter
 - (6) aftercooler dP and approach temperature
 - (7) compressor outlet pressure
 - (8) functionality of moisture separator and automatic drains

(b) *Dryer and Filter Subsystem*

- (1) prefilter, receiver, and afterfilter dP
- (2) air dryer exit dew point
- (3) particulate and oil content
- (4) pressure
- (5) flow rate
- (6) temperature

(c) *Distribution Subsystem*

- (1) pressure at the end use components
- (2) initial receiver pressure
- (3) pressure decay time
- (4) dew point (at line pressure) at the end use components
- (5) particulate and oil content at the end use components

VI-3.3.2 Instrumentation and Control (I&C) Characteristics. Include IA system instrumentation and control (I&C) characteristics that affect system-level performance as system characteristics in accordance with the requirements of para. 4.3.2 of this Part.

VI-3.3.3 System Logic Characteristics. Include IA system logic characteristics that affect system-level performance as system characteristics in accordance with the requirements of para. 4.3.3 of this Part. An example of IA system logic is isolation of cross-tied safety and nonsafety systems.

VI-3.4 Establish Characteristic Acceptance Criteria

Establish acceptance criteria for each system characteristic in accordance with the requirements of para. 4.4 of this Part.

VI-3.5 Develop Test Procedures and Perform Testing, Inspections, and Engineering Analysis

Develop and approve test procedures in accordance with para. 4.5 of this Part to verify that acceptance criteria derived in accordance with para. 4.4 of this Part are met.

VI-3.5.1 Preservice Testing. Develop and conduct tests to measure system performance in accordance with the requirements of para. 4.5.1 of this Part.

VI-3.5.1.1 Preservice Test Prerequisites. Identify prerequisites to preservice testing in accordance with the requirements of para. 4.5.1.1 of this Part. In addition, address the following IA system-specific requirements:

- (a) Visually inspect air receivers for external damage. If provided with a manhole, inspect internal receiver surfaces for contamination and corrosion.
- (b) If applicable, check pneumatic controls using dry air or nitrogen from an external source.
- (c) Verify trap and drain valve functionality (receiver, aftercooler separator, and compressor).

- (d) Operate the compressor in loaded mode to
 - (1) verify unload function
 - (2) verify operation of pressure and temperature trips
- (e) Run the dryer through one complete cycle to verify control system and valve operation.
- (f) Check for proper refrigerant and air heat exchanger temperature.

VI-3.5.1.2 Preservice Performance Test. Develop and conduct tests to measure system performance in accordance with the requirements of para. 4.5.1.2 of this Part. There are no specific requirements applicable to preservice testing that are beyond those stipulated in this Appendix for inservice testing. However, the testing of para. VI-3.5.2.1.1 need not be performed as part of the preservice testing.

VI-3.5.1.3 Preservice Test Interval. Perform preservice tests at an interval in accordance with para. 4.5.1.3 of this Part.

VI-3.5.2 Inservice Testing. Develop and conduct tests to measure system performance in accordance with the requirements of para. 4.5.2 of this Part.

VI-3.5.2.1 Inservice Performance Test. Develop and conduct tests to measure system performance in accordance with the requirements of para. 4.5.2.1 of this Part. In addition, address the following IA system-specific requirements:

VI-3.5.2.1.1 System Material Evaluation. Conduct the following tests and visual examinations:

- (a) Visually examine all internal surfaces accessible through inspection openings for corrosion, erosion, and abnormal corrosion products.
- (b) 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.
- (c) Nondestructive examinations may be performed as an alternative to the internal visual examination recommendations of (a) to ensure that vessel wall thickness meets requirements.
- (d) Examine prefilter and afterfilter cartridges for contamination levels.

VI-3.5.2.1.2 Compressor and Receiver Subsystem. Achieve stable compressor operation as close as practical to design conditions, and verify that the compressor and receiver subsystem supplies pressurized, cooled air to the dryer and filter subsystem at the required demand rate and pressure. Perform reduced flow tests when the compressor cycles at 4 load/unload cycles/hr. Verify operation of the unloaded system. Verify functionality of recycle and drain valves.

VI-3.5.2.1.3 Dryer and Filter Subsystem. Verify compressed air is processed by the dryer and filter subsystem to supply clean, dry air to the distribution network at the required dew point, cleanliness, demand rate, and pressure.

(a) Conduct the test for at least 8 hr, recording data at 1-hr intervals.

(b) Maintain dryer and filter inlet conditions as close as possible to design conditions including

- (1) compressed air at design operating temperature
- (2) test pressure at design pressure
- (3) compressor outlet flow rate at required capacity of the dryer and filters

(c) During the last 4 hr of the test, check discharge air from the afterfilter at 1-hr intervals for particulate and hydrocarbon contamination.

(d) During the last hour of the test, measure pressure drop across the filters (both pre- and after-filters) and across the air dryer.

(e) When purge air is derived from compressed air, determine purge air usage either by direct flow measurement or by measurement and comparison of outlet flow and inlet flow of the air dryer.

(f) When a desiccant dryer is equipped with an energy management system (moisture load controls), perform a second test to determine the dew point at reduced flow. Measure dew point at 1-hr intervals. For the test

- (1) provide two full cycles of the dryer
- (2) perform the test between 25% and 50% of design flow rate
- (3) perform the test at inlet temperatures that are as low as practical
- (4) verify the energy management function acceptance criteria are met

VI-3.5.2.1.4 Distribution Subsystem

(a) In accordance with para. 4.4 of this Part, establish a required minimum operational time for each special service air accumulator and the associated check valves upon loss of the main air system. Use the following sequence 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) Perform a static pressure decay test of the distribution subsystem to verify operational readiness.

(1) Before performing the test, place in service and align for normal operation all portions of the distribution subsystem.

(2) In accordance with para. 4.4 of this Part, establish acceptance criteria for minimum operational time with compressors tripped. Establish the system pressures at unload and load setpoints.

(3) Verify compressor load and unload setpoints with the compressor loaded and unloaded, with the system at required air usage.

(4) Conduct the test with the compressor isolated and air supplied to the system only from the receivers.

(c) Obtain air samples at the end of each major header in the system and verify acceptable dew point, oil content, and particulate content.

(d) Verify acceptable system pressure, and minimum and maximum cycle pressure and time; measurements should be made at the end of each major header.

VI-3.5.2.2 Inservice Test Interval. Perform inservice tests at an interval in accordance with para. 4.5.2.2 of this Part. See the following for additional IA system requirements.

VI-3.5.2.2.1 Compressor and Receiver; Dryer and Filter. Additional test interval requirements for the compressor, receiver, dryer, and filters are as follows:

(a) Conduct the system material evaluation tests of paras. VI-3.5.2.1.1(a) through VI-3.5.2.1.1(c) every 3 yr.

(b) Conduct leak testing using the pressure decay test of para. VI-3.5.2.1.4(a) for special service accumulators and associated check valves each fuel cycle.

(c) Conduct the inspections of para. VI-3.5.2.1.1(d) semiannually and at cartridge change out.

(d) Conduct the tests of paras. VI-3.5.2.1.3(c) and VI-3.5.2.1.3(d) quarterly.

VI-3.5.2.2.2 Distribution Network. Perform a pressure decay test similar to that described in para. VI-3.5.2.1.4(b) if compressor loading indicates an increase in system leakage. Alternatively, if the system has flow measurement capability, monitor flow rates to identify leakage. Analyze and trend the data to determine if compressor degradation or excessive system leakage has developed since the last test.

Part 28, Nonmandatory Appendix A Industry Guidance

Table A-1 in this Appendix contains operating experience information. The information focuses on events where improved testing might prevent the system from becoming degraded or unable to perform its intended safety functions. Table A-1 summarizes lessons learned from this information, which may be used in developing the test program. More detailed information is also available in the individual regulatory guides (RGs), licensee event reports (LERs), INPO operating experience reports (OEs), and information notices (INs) identified below.

The information in Table A-1 is current through January, 2007. Effort should be taken to utilize current published industry operating experience.

The events summarized in Table A-1 include information on the systems addressed in this Part, in addition to applicable lessons learned on other systems. The events fell into the following ten categories based on proximate cause:

- (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 post-modification testing
- (i) inadequate understanding of plant design basis
- (j) inadequate preoperational testing

Table A-1
Operating Experience Information

Category	Issue	Source(s) [Note (1)]	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 (piggy-back alignment for PWRs).
	...	LER 261-97008	System testing should address all potential (normal and off-normal) system alignments.
	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.
	Insufficient suction head conditions on turbine driven pumps	LER 305-05008	System tests to assure acceptable flow and NPSH conditions.
	Inadequate understanding of design basis	IN 98-40	Incorrect understanding of level instrument datum and uncertainties and post-accident pump flow rates may result in inadequate NPSH.
	Impact of NPSH due to addition of gas	IN 2002-18	Addition of gas to water storage tanks can result in inadequate NPSH.
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; LER-305-02001; OEI0478	Consider the potential for pump operation near shutoff head causing deadheading of the weaker pump when pumps operate in parallel alignment.
	Miniflow recirculation line	IN 87-59	Verify ECCS pump miniflow recirculation.
	Flow capacity	Lines have adequate flow capacity for multiple pump operation	...

Table A-1
Operating Experience Information (Cont'd)

Category	Issue	Source(s) [Note (1)]	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
	Gas intrusion	IN 88-23 Supplement 3: LERs 50-455/91-12, 455/90-35,213/90-08 INPO SER 2-05	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.
	Air intrusion	IN 2006-21	Inadequate determination of BWST switchover set-points results in air intrusion to ECCS.
Incorrect emergency diesel generator electrical loading	Emergency diesel generators 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.
	Emergency diesel generator 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.
	Nonconservative acceptance criteria in SR pump surveillance test	IN 97-90	The licensee concentrated on 1st requirements without ensuring the design requirements were met. Acceptance criteria based on ASME component limits that were less limiting than design basis requirements.
	Surveillances do not test and verify acceptable system resistance.	OE-19856	Surveillance tests do not test and verify acceptable system resistance to ensure the minimum required flow.
	Failure to consider line resistance results in overestimated pump performance	LER 213-95022	Surveillance test acceptance criteria need to address available plant conditions during tests.
	Limited flow test range is inadequate to confirm acceptable performance	OE6615	Testing range must include minimum and maximum flow acceptance criteria.
Inadequate post-modification 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.
	Rebuilt pump performance exceeds nonrebuilt pump performance	LER 387-99066; OE-10478	Inadequate post modification testing (all mode of operation) did not reveal design deficiency.
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.

Table A-1
Operating Experience Information (Cont'd)

Category	Issue	Source(s) [Note (1)]	Lessons Learned
Inadequate understanding of plant design basis	Inability to achieve system design basis flow	LER 483-02002	Calculation error in establishing system flow requirements (incorrect basis) resulted in incorrect recirculation flow and unacceptable delivered flow.
	Lack of technical qualifications of personnel	LER 315-99023	The design basis requirements for ESW availability during an accident were inadequately understood.
	Testing configurations violate mode required system/ component availability	OE 10153	Test alignments should not violate mode dependent technical specification requirements for system or component operability.
	Inadequate assessment of effect of differential temperatures on safety related pumps	IN 2000-08	Safety related pumps may operate under conditions where either the pumped fluid undergoes a large temperature change or there is a large temperature difference between the pump fluid and cooling water. These situations can lead to pump damage or cause the pump to trip if not adequately incorporated into design.
	Downstream effects of sump debris	GL 2004-02	Sump debris that passes through sump screen may result in blockage or damage to downstream equipment.
Inadequate preoperational testing	Preoperational testing did not address all operating modes	LER 423-96029	Testing did not address recirculation piggy-back alignment resulting in pump runout.

NOTE: (1) Sources listed in Table A-1 are available through the Nuclear Regulatory Commission at www.nrc.gov/reading-rm/doc-collections/.

Part 28, 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) ECCS accumulator discharge flow path resistance
- (b) pump total dynamic head (TDH) versus flow
- (c) pump discharge flow path overall resistance
- (d) balanced branch line resistance

B-2 VERIFYING ECCS 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 PROCESS SUBSYSTEM

A typical process subsystem is shown in Figure B-1 to support the discussions in sections B-4 through B-7. The subsystem is shown with the pumps aligned to distribute to the serviced components by means of four branch lines. The isolated paths represent additional normal or post-accident distribution paths that may be isolated during the test. In addition, the subsystem may have pump minimum recirculation flow paths, which are not shown in this Figure.

B-4 IDENTIFYING AND VERIFYING PUMP TDH VERSUS FLOW ACCEPTANCE CRITERIA

The system hydraulic analysis for a given event or system alignment is based on system delivered flow as a function of boundary conditions specific to that event or alignment. Some analyses use minimum system flow (e.g., small break LOCA) and some use maximum

system flow (e.g., inadvertent ECCS actuation or steam generator overfill). The minimum and maximum system flows establish limits on the system pump minimum required and maximum allowable performances. These limits are the acceptance criteria for the system characteristic of pump TDH versus flow.

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. This data may be obtained using a temporary alignment or dedicated test return line in lieu of the designed system flow path. Acceptance criteria developed in accordance with para. 4.4 of this Part will be minimum and maximum TDH versus flow. Figure B-2 graphically illustrates correction of measured data for instrument accuracy as described in para. 4.4 of this Part. Figure B-3 illustrates the same data points with analysis limits corrected for instrument accuracy as described in para. 4.4 of this Part. Both figures illustrate acceptable test results.

B-5 VERIFYING DISCHARGE FLOW PATH RESISTANCE

The system flow rates used in the system hydraulic analysis are a function of the pump performance, system resistances, and system boundary conditions, including parallel flow paths. The minimum and maximum flow rates used in the event analysis will place limits on the pump discharge flow path resistance and branch line balance. In addition, minimum limits on system resistance may be necessary in order to prevent pump runout (e.g., for PWRs, during long-term core cooling operation when ECCS pumps may be operated in series). These minimum and maximum limits are the acceptance criteria for the system characteristic of pump discharge flow path resistance.

Consider paths that may divert flow from the desired flow path when verifying system resistance. Examples of such paths are pump minimum recirculation paths, reactor coolant pump seal injection paths, unisolated nonessential component cooling water paths, and supply paths to other pumps during series pump operation. Establish minimum resistance limits for these diversion paths to ensure minimum desired flow and to prevent pump runout. Establish maximum limits to ensure that the diversion flow paths support their design function. These

Figure B-1
Typical Branch Line System

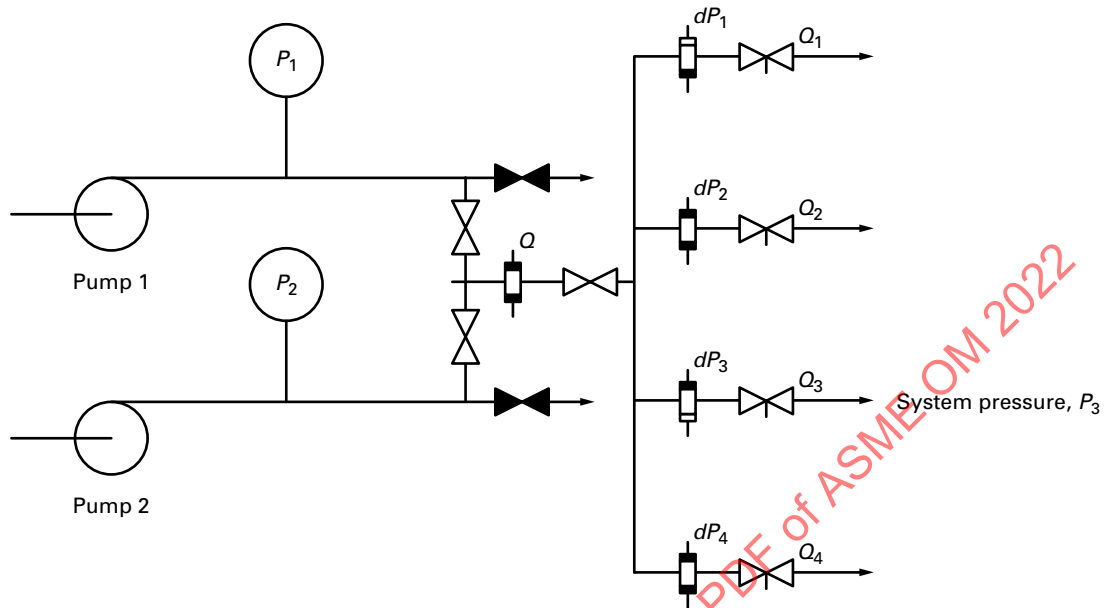


Figure B-2
Verifying Pump TDH Versus Flow: Correction of Measured Data for Instrument Accuracy

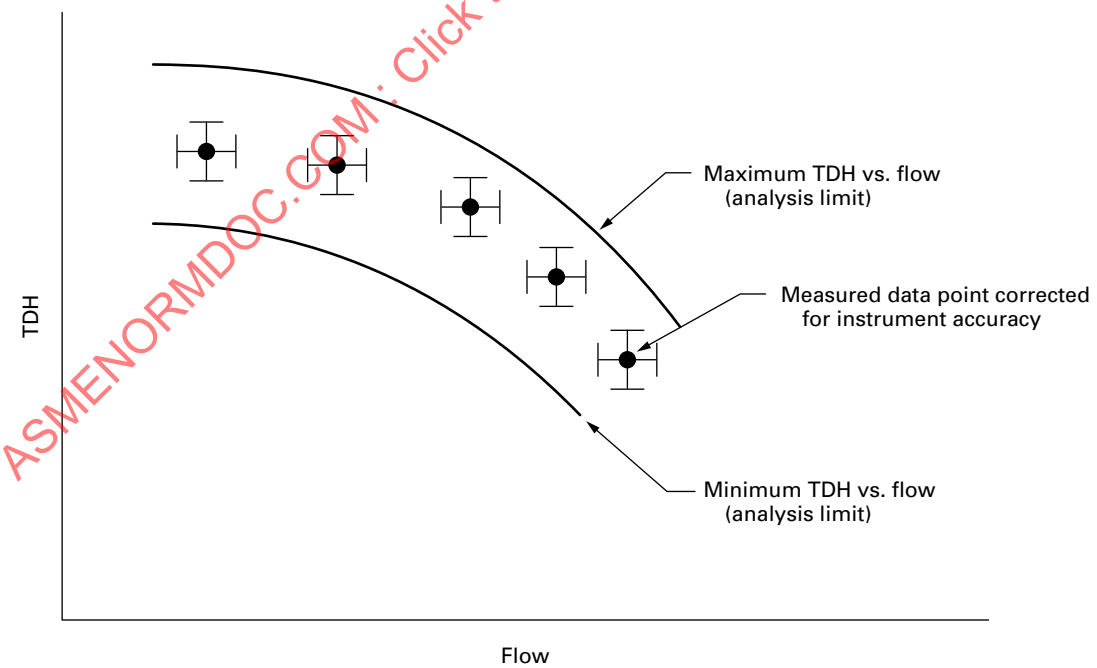
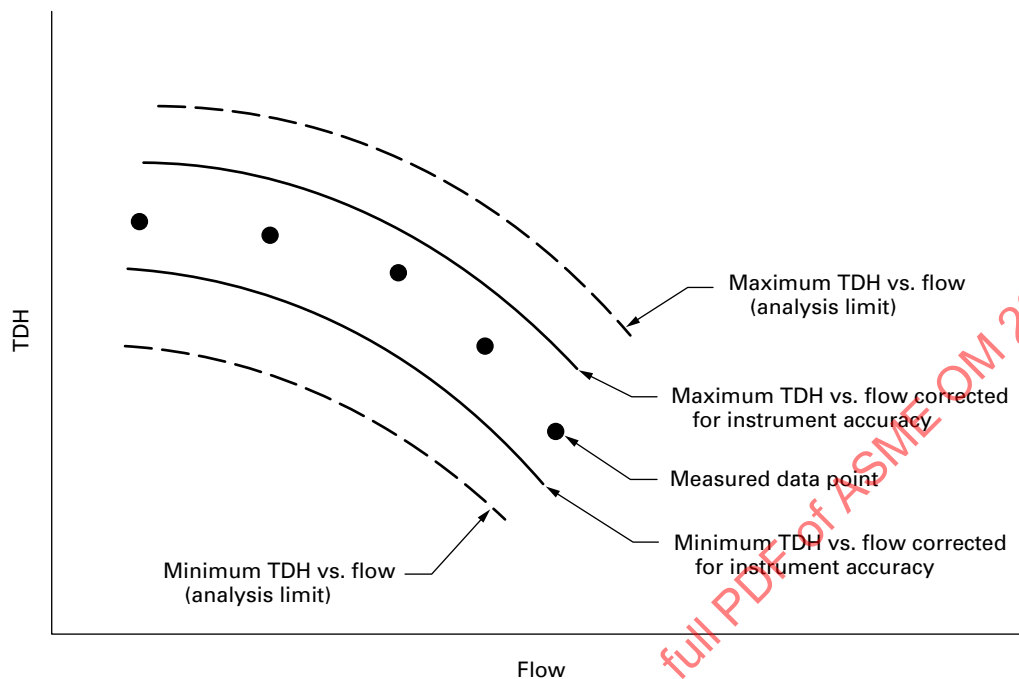


Figure B-3
Verifying Pump TDH Versus Flow: Correction of Analysis Limits for Instrument Accuracy



minimum and maximum limits form acceptance criteria for the individual diversion flow path resistances.

Verification of this system characteristic, for the subsystem pictured in Figure B-1, involves operating either pump while recording pump discharge pressure, P_1 or P_2 , as appropriate, total pump flow, Q , and calculating back pressure, P_3 . Discharge flow path overall resistance, K_{measured} , is then calculated as follows:

$$K_{\text{measured}} = \frac{P_1 - P_3}{Q_{\text{pump1}}^2} \text{ or } \frac{P_2 - P_3}{Q_{\text{pump2}}^2}$$

where

- K = discharge flow path resistance
- P_1, P_2 = pump discharge pressure
- P_3 = back pressure
- Q = total pump flow rate

This equation results from an application of Bernoulli's equation between the pump discharge and the point where P_3 is measured. The equation assumes that changes in elevation and velocity heads are negligible in comparison with 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 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 resis-

tance is a function of Reynolds number and is dependent upon fluid velocity and temperature. If the fluid velocity and temperature at the test conditions vary significantly from design conditions, use of the above 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. Compare the noncommon flow paths to confirm this. A stronger pump will have an operating point on a given system that 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. 4.4 of this Part will be K_{minimum} and K_{maximum} . 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 illustrates correction of measured data for instrument accuracy, while Figure B-5 illustrates the same measured data with analysis limits corrected for

Figure B-4
Verifying Discharge Piping Overall Resistance: Correction of Measured Data for Instrument Accuracy

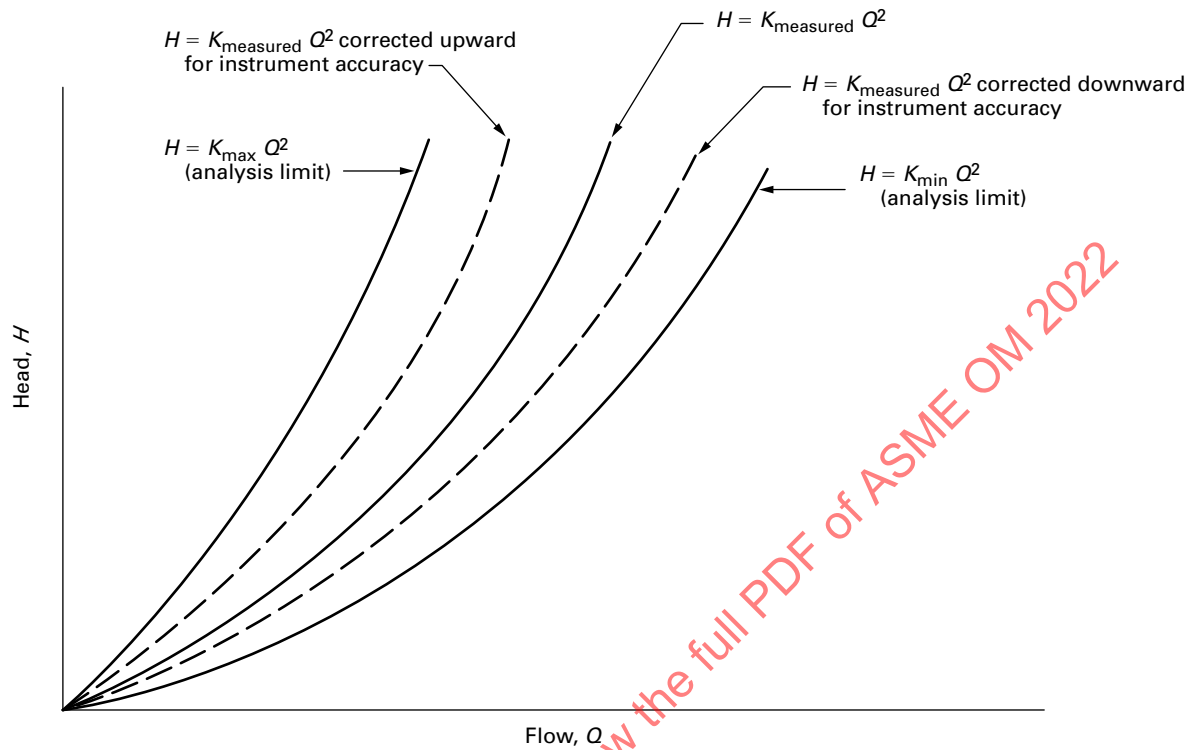
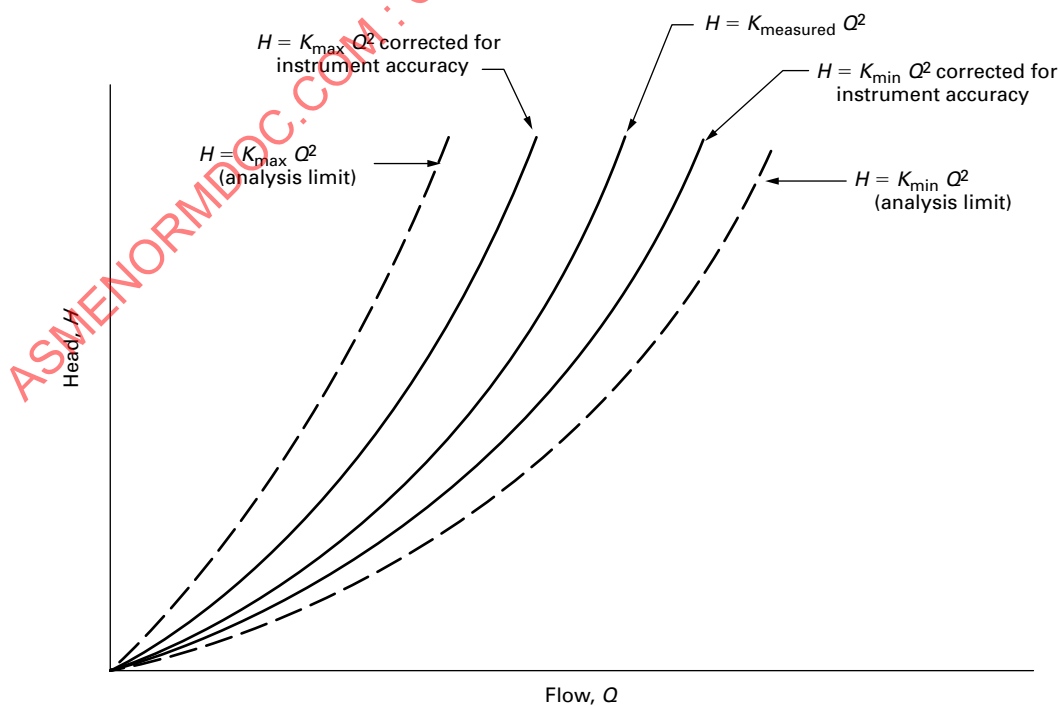


Figure B-5
Verifying Discharge Piping Overall Resistance: Correction of Analysis Limits for Instrument Accuracy



instrument accuracy. Both figures illustrate acceptable test results.

B-6 VERIFYING BALANCED BRANCH LINE RESISTANCE

Meeting the system performance requirement for delivered flow may require a defined balance between system branch lines. Typically this performance requirement is defined as a relative difference in branch line hydraulic resistance, which can be difficult to measure on individual branch lines. Therefore, balance acceptance criteria can be expressed in terms of an allowable difference in either branch line flow rates or the related parameter of differential pressure (dP) across branch line flow elements.

For the system pictured in Figure B-1, verifying the system characteristic of balanced branch line resistance requires operating either pump while recording flow element differential pressures dP1, dP2, dP3, and dP4. If the acceptance criterion is a relative 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 relative flow difference is compared against the acceptance criterion. If the acceptance criterion is relative allowable dP difference, the relative test dP difference is compared against the acceptance criterion. In this instance, meeting the requirements of para. 4.4 of this Part 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 these limits as criteria against measured data.

B-7 SYSTEM ADJUSTMENTS

B-7.1 Acceptance Criteria: Section B-4

If the testing described in section B-4 does not meet acceptance criteria, the available options are to

(a) rework or replace the pump and retest.

(b) if possible, refine the analysis on which the acceptance criteria are based such that the measured data meets the revised acceptance criteria. In most cases, the system flow rates are a function of 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.

B-7.2 Acceptance Criteria: Section B-5 or Section B-6

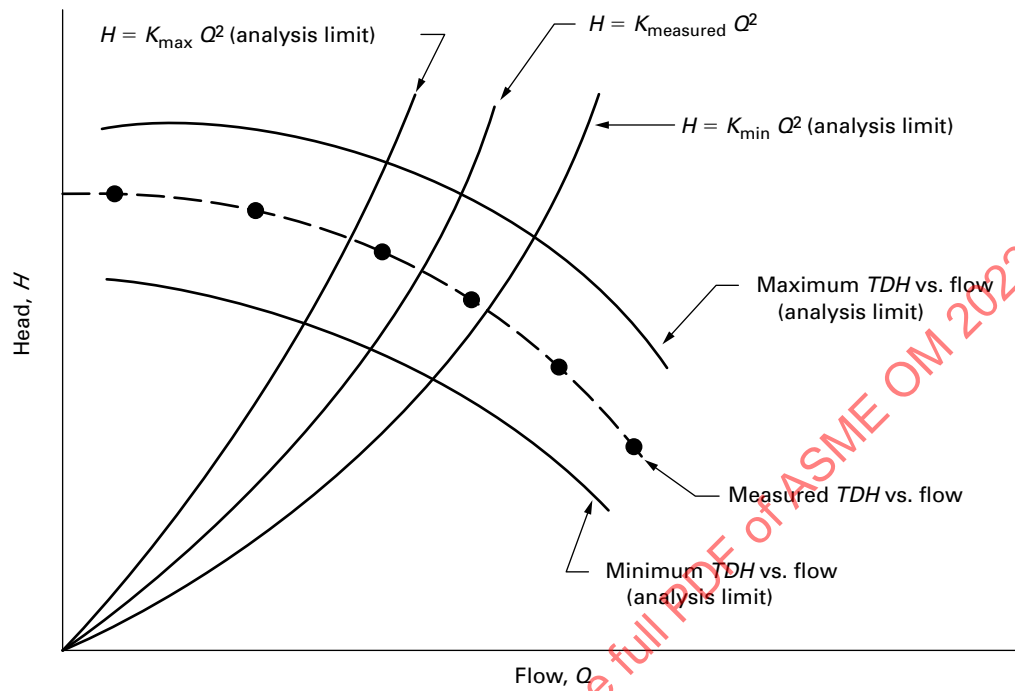
If the testing described in section B-5 or section B-6 does not meet acceptance criteria, the available options are to

(a) re-orifice (or adjust throttle valves) and retest the system as required to meet the discharge flow path overall resistance and balanced branch line resistance acceptance criteria. In the system depicted in Figure B-1, this is accomplished by adjusting the four throttle valves downstream of the flow elements.

(b) refine the analysis per para. B-7.1(b).

The final result of implementing sections B-4 through B-7 for a system is graphically depicted in Figure B-6. Note that Figure B-6 does not include any corrections for instrument accuracy.

Figure B-6
Measured Subsystem Operating Point and Range of Operating Points Allowed by Analysis Limits



Part 28, 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, etc. 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 verified 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 for verifying that measured system flow (Q), pump total developed head (TDH), and system resistance (K) meet acceptance criteria, assuming 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_D	= discharge pipe inside diameter, in.
D_P	= pipe inside diameter, in.
D_S	= suction pipe inside diameter, in.
d	= total differential operator
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 back pressure, 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
v	= specific volume, ft ³ /lbm
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_V	= difference in velocity head, ft
ΔH_Z	= difference in elevation head, ft
ΔP	= difference in pressure, psid

¹ This designates the elevation corresponding to the pressure measurement. This is usually the elevation of the pressure gauge or transmitter. However, occasionally, adjustment is made for the elevation head between the pressure tap and the pressure gauge or transmitter in the calibration; in this case, the elevation of the pressure tap should be used.

² This designates the velocity in the fluid stream at the location of the pressure tap.

μ = dynamic viscosity, lbm/ft-sec
 ∂ = partial differential operator

C-3 SENSITIVITY COEFFICIENTS

The reference in para. 3(c) of this Part 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 ($u, v, w, \dots$), 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

$$Y = f(u, v, w, \dots)$$

The total differential is the sum of the partial differentials of the independent variables

$$dY = \frac{\partial Y}{\partial u} du + \frac{\partial Y}{\partial v} dv + \frac{\partial Y}{\partial w} dw + \dots$$

Dividing the equation for dY by Y yields an equation of the form

$$\frac{dY}{Y} = X_u \frac{du}{u} + X_v \frac{dv}{v} + X_w \frac{dw}{w} + \dots$$

where

$$X_u = \frac{u}{Y} \frac{\partial Y}{\partial u} = \frac{\frac{\partial Y}{Y}}{\frac{\partial u}{u}}$$

and $\frac{du}{u}$ is the fractional change in u .

If the functional relation is of the form

$$Y = C u^l v^m w^n \dots$$

then

$$\begin{aligned} X_u &= l \\ X_v &= m \\ X_w &= n \end{aligned}$$

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:

$$(Acc)_Y = \pm \left\{ [X_u(Acc)_u]^2 + [X_v(Acc)_v]^2 + [X_w(Acc)_w]^2 + \dots \right\}^{1/2}$$

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 (v) to fundamental measured properties such as pressure and temperature. The accuracy with which specific volume is known is made up of the following three parts:

- (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. The overall accuracy can be written as

$$(Acc)_v = (Acc)_{\text{Correlation}} + \left\{ [X_T(Acc)_T]^2 + [X_p(Acc)_p]^2 \right\}^{1/2}$$

where

$$\begin{aligned} X_T &= \alpha T \\ X_p &= -\beta_T P \\ \alpha &= \frac{1}{v} \frac{\partial v}{\partial T} \text{ (volume expansivity)} \end{aligned}$$

$$\beta_T = -\frac{1}{v} \frac{\partial v}{\partial P} \text{ (isothermal compressibility)}$$

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 form

$$Q = SKD^2 \sqrt{\nu \Delta P}, \text{ where } S \text{ is a constant.}$$

The overall accuracy can be expressed as

$$(Acc)_Q = \pm \left\{ \left[X_K(Acc)_K \right]^2 + \left[X_D(Acc)_D \right]^2 + \left[X_{\Delta P}(Acc)_{\Delta P} \right]^2 + \left[X_D(Acc)_D \right]^2 \right\}^{1/2}$$

where

$$\begin{aligned} X_D &= 2 \\ X_K &= 1 \\ X_\nu &= \frac{1}{2} \\ X_{\Delta P} &= \frac{1}{2} \end{aligned}$$

The treatment of the above variables is discussed in the following paragraphs.

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, etc.) or application (e.g., diameter ratio limits, pipe size limits, or Reynolds number limits, etc.) 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 (Reynolds number, diameter ratio, etc.) 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 is treated in detail in section C-5.

C-7 ACCURACY OF PUMP TDH

The 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

$$(Acc)_{TDH} = \pm \left\{ \left[X_\nu(Acc)_\nu \right]^2 + \left[X_{P_D}(Acc)_{P_D} \right]^2 + \left[X_{P_S}(Acc)_{P_S} \right]^2 + \left[X_{\Delta Z}(Acc)_{\Delta Z} \right]^2 + \left[X_Q(Acc)_Q \right]^2 + \left[X_{D_P}(Acc)_{D_P} \right]^2 \right\}^{1/2}$$

where

$$X_{D_P} = 4 \frac{\Delta H_V}{TDH}$$

$$X_{P_D} = \frac{\Delta H_P}{TDH} \left(\frac{P_D}{P_D - P_S} \right)$$

$$X_{P_S} = \frac{\Delta H_P}{TDH} \left(\frac{P_S}{P_D - P_S} \right)$$

$$X_Q = 2 \frac{\Delta H_V}{TDH}$$

$$X_v = \frac{\Delta H_P}{TDH}$$

$$X_{\Delta Z} = \frac{\Delta H_Z}{TDH}$$

The following observations are made concerning this expression. First, 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. Second, 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. Third, the accuracy of velocity head is broken into two terms: the accuracy with which the flow rate is known and 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:

$$h_L = 144v(P_D - P_B) + (Z_D - Z_B) + \frac{V_D^2 - V_B^2}{2g}$$

$$h_L = \Delta H_P + \Delta H_Z + \Delta H_V$$

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.

$$(Acc)_K = \pm \left\{ \begin{aligned} & \left[X_v(Acc)_v \right]^2 + \left[X_{P_D}(Acc)_{P_D} \right]^2 \\ & + \left[X_{P_B}(Acc)_{P_B} \right]^2 + \left[X_{\Delta Z}(Acc)_{\Delta Z} \right]^2 \\ & + \left[X_Q(Acc)_Q \right]^2 + \left[X_{D_P}(Acc)_{D_P} \right]^2 \end{aligned} \right\}^{1/2}$$

where

$$X_{D_P} = 4 \frac{\Delta H_V}{h_L}$$

$$X_{P_B} = \frac{\Delta H_P}{h_L} \left(\frac{P_B}{P_D - P_B} \right)$$

$$X_{P_D} = \frac{\Delta H_P}{h_L} \left(\frac{P_D}{P_D - P_B} \right)$$

$$X_Q = 2 \left(\frac{\Delta H_V}{h_L} - 1 \right)$$

$$X_v = \frac{\Delta H_P}{h_L}$$

$$X_{\Delta Z} = \frac{\Delta H_Z}{h_L}$$

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 section 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

Section C-7 provides the following equation for determining the accuracy of pump TDH.

$$(Acc)_{TDH} = \pm \left\{ \begin{aligned} & \left[X_v(Acc)_v \right]^2 + \left[X_{P_D}(Acc)_{P_D} \right]^2 \\ & + \left[X_{P_S}(Acc)_{P_S} \right]^2 + \left[X_{\Delta Z}(Acc)_{\Delta Z} \right]^2 \\ & + \left[X_Q(Acc)_Q \right]^2 + \left[X_{D_P}(Acc)_{D_P} \right]^2 \end{aligned} \right\}^{1/2}$$

Table C-1
Recorded Test Data

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 gal/min	0.09969 m ³ /s
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

There are two aspects of evaluating the uncertainty in pump TDH. First, the sensitivity coefficients (X_i) must be determined for each parameter that is used to calculate the TDH. Second, the accuracy, $(Acc)_i$, of each individual parameter must be determined.

C-9.1.1 Evaluation of Pump TDH Sensitivity Coefficients.

The data in Table C-1 was recorded during a test. The specific volume at the test temperature and the pump discharge pressure is 0.016 ft³/lbm (0.0009989 m³/kg). The specific volume, along with the information in Table C-1, can be used to calculate the parameters in Table C-2.

These parameters can be used to determine the sensitivity coefficients by means of the following formulas provided in section C-7:

$$X_{Dp} = 4 \frac{\Delta H_V}{TDH}$$

$$X_{P_D} = \frac{\Delta H_p}{TDH} \left(\frac{P_D}{P_D - P_S} \right)$$

$$X_{P_S} = \frac{\Delta H_p}{TDH} \left(\frac{P_S}{P_D - P_S} \right)$$

$$X_Q = 2 \left(\frac{\Delta H_V}{TDH} \right)$$

$$X_v = \frac{\Delta H_p}{TDH}$$

$$X_{\Delta Z} = \frac{\Delta H_Z}{TDH}$$

The sensitivity coefficients calculated in this manner are summarized in Table C-3.

Table C-2
Calculated Pump Head

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

Table C-3
Sensitivity Coefficients for Pump TDH

Parameter	Sensitivity Coefficient	Value
Specific volume	X_v	0.9956
Discharge pressure	X_{P_D}	1.0251
Suction pressure	X_{P_S}	0.0295
Elevation difference	$X_{\Delta Z}$	0.0018
Flow rate	X_Q	0.0052
Pipe diameter	X_D	0.0104

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 $(Acc)_v \ll (Acc)_p$, ignore the effect of specific volume on overall accuracy. If it is then assumed 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 gauge 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 the following three parts:

- (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.

$$(Acc)_v = \pm (Acc)_{\text{Correlation}} \pm \left\{ \left[X_T (Acc)_T \right]^2 + \left[X_p (Acc)_p \right]^2 \right\}^{1/2}$$

where

$$X_p = -\beta_T P$$

$$X_T = \alpha T$$

$$\alpha = \frac{1}{v} \frac{\partial v}{\partial T} \text{ (volume expansivity)}$$

$$\beta_T = -\frac{1}{v} \frac{\partial v}{\partial P} \text{ (isothermal compressibility)}$$

The uncertainty in the specific volume correlation as a function of pressure and temperature was obtained from the reference in para. 3(b) of this Part. Over the range 0 psia to 1,450 psia (0 bar to 100 bar) and 32°F to 212°F (0°C to 100°C) the uncertainty in the correlation is $d_v/v = 0.0004$ 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 reference in para. 3(b) of this Part (within the ranges 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:

$$\frac{\partial v}{\partial P} = -5 \times 10^{-8} \frac{\text{ft}^3/\text{lb}_m}{\text{psi}} \left(-4.5 \times 10^{-10} \frac{\text{m}^3/\text{kg}}{\text{kPa}} \right)$$

$$\frac{\partial v}{\partial T} \leq -2.375 \times 10^{-6} \frac{\text{ft}^3/\text{lb}_m}{^\circ\text{F}} \left(\leq 2.7 \times 10^{-7} \frac{\text{m}^3/\text{kg}}{^\circ\text{C}} \right)$$

A specific volume of $0.016 \text{ ft}^3/\text{lb}_m$ ($0.0009989 \text{ m}^3/\text{kg}$) results in

$$\beta_T = -\frac{1}{v} \frac{\partial v}{\partial P} = 3.121 \times 10^{-6} \frac{\text{in.}^2}{\text{lb}} \left[4.5 \times 10^{-7} (\text{kPa})^{-1} \right]$$

$$\alpha = \frac{1}{v} \frac{\partial v}{\partial T} = 1.483 \times 10^{-4} (^\circ\text{F})^{-1} \left[2.7 \times 10^{-4} (^\circ\text{C})^{-1} \right]$$

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 Celsius.

The pressure gauge 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.

$$(Acc)_P = \frac{dP}{P} = \frac{0.01(3,000 \text{ psi})}{745 \text{ psia}}$$

$$= 0.04 \left[\frac{0.01(21,000 \text{ kPa})}{5,137 \text{ kPa}} = 0.04 \right]$$

$$(Acc)_T = \frac{dT}{T} = \frac{0.02(150^\circ\text{F})}{70^\circ\text{F}} = 0.04 \left[\frac{0.02(85^\circ\text{C})}{21.1^\circ\text{C}} = 0.08 \right]$$

$$(Acc)_v = \pm (Acc)_{\text{Correlation}}$$

$$\pm \left\{ \left[X_T (Acc)_T \right]^2 + \left[X_P (Acc)_P \right]^2 \right\}^{1/2}$$

$$(Acc)_v = \pm 0.0004$$

$$\pm \left\{ \left[0.0104(0.04) \right]^2 + \left[0.0023(0.04) \right]^2 \right\}^{1/2}$$

$$= 0.0008$$

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) and had an accuracy of 1.0% of instrument span.

$$(Acc)_P = \frac{dP_S}{P_S} = \frac{0.01(100 \text{ psi})}{36 \text{ psi}}$$

$$= 0.028 \left[\frac{0.01(700 \text{ kPa})}{248 \text{ kPa}} = 0.028 \right]$$

C-9.1.2.4 Elevation Difference. The elevation difference measure is known to within 3 in. (7.6 cm). Therefore, the accuracy is

$$(Acc)_{\Delta Z} = (3 \text{ in.}) (1 \text{ ft}/12 \text{ in.}) / (3 \text{ ft}) = 0.8$$

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.

$$(Acc)_Q = \pm \left\{ \left[X_K (Acc)_K \right]^2 + \left[X_D (Acc)_D \right]^2 \right. \\ \left. + \left[X_{\Delta P} (Acc)_{\Delta P} \right]^2 + \left[X_v (Acc)_v \right]^2 \right\}^{1/2}$$

where

$$X_D = 2$$

$$X_K = 1$$

$$X_v = \frac{1}{2}$$

$$X_{\Delta P} = \frac{1}{2}$$

Table C-4
Pump TDH Overall Accuracy Calculation

Parameter	Sensitivity Coefficient, X_1	Accuracy, $(Acc)_I$	$[X_I(Acc)_I]^2$
V	0.9956	0.0008	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	0.0104	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

$$(Acc)_K = (Bias)_{Influence} \pm (Acc)_{Correlation} \pm (Acc)_{Inputs}$$

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,

$$(Acc)_{D_P} = \frac{dD_P}{D_P} = \frac{0.01 \text{ in.}}{5.761 \text{ in.}} = 0.0017$$

C-9.2 Results

$$(Acc)_{TDH} = \pm \left\{ \begin{aligned} &[X_V(Acc)_V]^2 + [X_{P_D}(Acc)_{P_D}]^2 \\ &+ [X_{P_S}(Acc)_{P_S}]^2 + [X_{\Delta Z}(Acc)_{\Delta Z}]^2 \\ &+ [X_Q(Acc)_Q]^2 + [X_{D_P}(Acc)_{D_P}]^2 \end{aligned} \right\}^{1/2}$$

The sensitivity coefficients and accuracies are summarized in Table C-4.

It is seen that the accuracy of the pump TDH is dominated by the accuracy of the discharge pressure.

DIVISION 3 OM GUIDES

Part 11 Vibration Testing and Assessment of Heat Exchangers

1 INTRODUCTION

1.1 Scope

This Part provides requirements for preservice and inservice testing to assess the vibration of certain heat exchangers used in water-cooled reactor 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 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.

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

(a) 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 (www.ansi.org)

(b) 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, 807 Union Street, Schenectady, NY 12308

(c) Robert D. Blevins, "Flow-induced Vibration," 2nd Edition, Van Nostrand Reinhold, 1990

(d) M. K. Au-Yang, "Flow-induced Vibration of Power and Process Plant Components," Professional Engineering Pub., 2001

(e) "Review of Lessons Learned from the San Onofre Steam Generator Tube Degradation Event," March 6, 2015, USNRC ADAMS Accession No. ML15015A419

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 ten-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 and residual heat removal heat exchangers.

There is a history of tube vibration problems in shell-and-tube heat exchangers. 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 of this Part.

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

Select heat exchangers to be included in the test program in accordance with this Part. Use criteria based on applications where heat exchanger designs are susceptible to excessive vibration or for first-of-a-kind heat exchanger designs. (Refer to Nonmandatory Appendix A for discussion.) Consider the following factors in selecting the heat exchangers to be included:

- (a) the importance of the heat exchanger
- (b) gas or two-phase fluid flowing on the shell side
- (c) previous operational experience with a similar design
- (d) available design analysis and laboratory test data
- (e) equipment configuration
- (f) a high flow rate or significant increase in the flow rate

5.1.1 For a new design, test the heat exchanger in accordance with para. 6. The following conditions may be used in lieu of new tests to demonstrate the adequacy of a heat exchanger:

(a) The design of the heat exchanger under consideration is derived from a reference design (tested prototype or existing design) with proven structural integrity to permit a comparative flow-induced vibration analysis, using the reference design as the basis.

Evaluate the following factors to establish that the 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
- (4) operational experience

(b) A comparative analysis shows that the heat exchanger under consideration is no more susceptible to fluidelastic instability in all directions,¹ 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 (a)(1) through (a)(4) do not invalidate these simple extrapolations. Nonmandatory Appendix B of this Part includes correlations that may be used in lieu of more specific information.

5.1.2 For heat exchanger designs that use a proven heat exchanger design as a reference but have some material, 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 all of 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 in all directions,¹ 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 heat exchanger. For example, mechanical testing that determines tube dynamic characteristics can demonstrate the similarity

¹ Fluidelastic instability can occur in all directions as documented in the reference in para. 3(e).

of subsequently manufactured units to a flow-tested unit. (Guidelines for dynamic tube tests are provided in Non-mandatory Appendix C.)

(d) System (piping and valve configurations) and heat exchanger supports are similar. (Changes in the fluid system or heat exchanger supports could result in flow imbalance or tube support motions that are reflected in tube vibration.)

5.1.3 Examples of differences that might be shown to be acceptable according to paras. 5.1.2(a) through 5.1.2(d) 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

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 Implementation of each of these measurement methods and guidelines for evaluation and interpretation of the results are provided in section 7. The information obtained from each test method and their limitations are summarized below.

6.1.2.1 External Monitoring for Impacting Test Method

- (a) External monitoring can accomplish 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

- (b) External monitoring is limited because

- (1) impacts may not be adequately detectable for determination of the flow rate at which impacting occurs by external accelerometers

- (2) the particular tubes or number of tubes that are impacting cannot be identified for further investigation of specific tubes

- (3) quantitative information is not obtained

6.1.2.2 Microphone Scan to Detect Impacting

- (a) Microphone scan can accomplish 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

- (b) Microphone scan is limited because

- (1) This method cannot provide detailed quantitative data such as can be acquired by direct measurement with in-tube probes.

- (2) The tube sheet must be accessible during testing.

6.1.2.3 Direct Measurement of Tube Response

- (a) Direct measurement of tube response can do the following:

- (1) This method can provide vibration response amplitude and frequency information for specific tubes.

- (2) It provides the best basis for assessing the potential for vibration-induced wear or fatigue.

- (b) Direct measurement of tube response is limited because 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.

Apply the direct measurement method 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, demonstrate adequate detection of impacts by externally mounted accelerometers for the heat exchanger under consideration.

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, use the direct measurement method 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 of this Part.

7 TEST REQUIREMENTS

7.1 Direct Measurement of Tube Vibration

7.1.1 Introduction. Use data from direct measurement of tube vibration to perform 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. Base the selection of tubes to be instrumented 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, conduct an acoustic survey of the tube ends at the tube sheet (see para. 7.2) 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 Consider the design features that can result in high velocity and/or turbulence regions, and then determine which tubes are likely to be more susceptible to fluidelastic instability and turbulence excitation, or both. 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 of this Part). 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 Figure 1, various tube bundle configurations that 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 Figure 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 Figure 1, it is recommended that tubes from the groupings indicated in the appropriate sketch in Figure 1 be included in those chosen to be instrumented in a vibration monitoring program.

As a precaution, note 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.

Consider 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 as the primary tube locations that should be considered in the evaluation of vortex shedding.

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) Install accelerometers to measure vibration in two orthogonal directions in a plane that is perpendicular to the tube centerline. Position the accelerometers axially within a heat exchanger tube at a point that will result in sufficiently large acceleration signals for all modes of interest. Use calculations 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

Evaluate the effect of dissolved gases on sensor life. 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.

Use biaxial accelerometers. If two single axis accelerometers are used, consider the effects of the separation of the accelerometers. Test the accelerometers used immediately prior to mounting to ensure operability, and handle the accelerometers with care during the installation process.

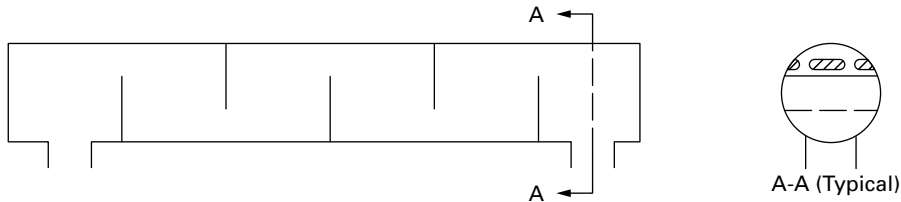
(2) Cables frequently require more consideration than the accelerometer. Meet the following requirements for cable installation:

- (-a) Restrain and protect cables to prevent chafing, fretting, and noise generated by cable whip.
- (-b) Use metal-sheathed cables with a mineral oxide dielectric insulation when temperatures exceed 500°F (260°C).
- (-c) Use low-noise (treated) cables designed specifically for accelerometer applications.
- (-d) Do not exceed the cable length recommended by the signal conditioner manufacturer.

(3) Use signal conditioners specifically designed for application with the test accelerometer. Consider the following in the selection of signal conditioning instrumentation:

- (-a) Use remote charge converters or preamplifiers for piezoelectric accelerometers without internal amplifying electronics when cable runs exceed 100 ft (30 m). Consider using remote charge converters or preamplifiers for piezoelectric accelerometers without internal amplifying electronics when cable runs exceed 25 ft (7.6 m).
- (-b) Use the signal conditioner in accordance with the manufacturer's environmental ratings (remote monitoring location or test enclosures may be necessary).

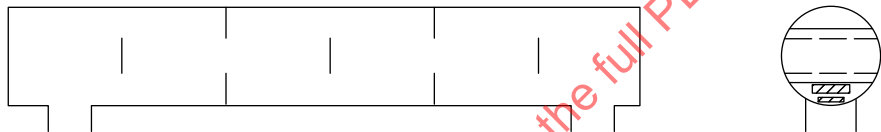
Figure 1
Tube Bundle Configuration With Tube Groupings Most Susceptible to Fluidelastic Instability
Denoted by Cross-Hatching



(a) Single-Segmental, Transverse-Cut Baffles



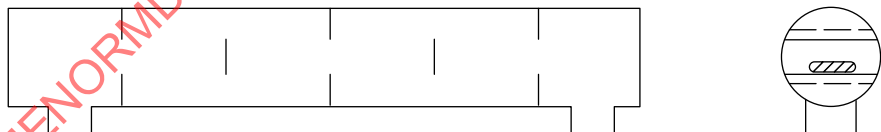
(b) Single-Segmental, Parallel-Cut Baffles



(c) Double-Segmental, Transverse-Cut Baffles



(d) Double-Segmental, Parallel-Cut Baffles



(e) Double-Segmental, Transverse-Cut Baffles



(f) Double-Segmental, Parallel-Cut Baffles

(-c) Use a signal conditioner with multiple gain ranges to allow maximum amplification without signal distortion.

(-d) Filter the signals 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. Consider the following when using strain gages:

(1) Mount strain gages in orthogonal pairs.

(2) Place the strain gage with the axial position in the region of maximum bending, typically at the tube sheet.

(3) Align the axes of sensitivity of the gages with the tube axis.

(4) Use three gages at a single axial location 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 of this Part 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) Take the following precautions and considerations into account to avoid damage to strain gage cables:

(-1) Avoid excessive bending or pulling of the strain gage cable during installation.

(-2) Restrain the cables after installation to prevent chafing, fretting, or separation from the strain gage.

(-3) Use metal-sheathed cables with a mineral oxide dielectric when temperatures exceed 500°F (260°C), since a breach in the outer sheath may result in cable failure.

(-e) Use strain gage amplifiers in accordance with the following:

(-1) Individually connect each strain gage signal to separate amplifiers (i.e., quarter bridges).

(-2) Provide signal conditioners with provisions for balancing the gage and for sensitivity compensation.

(-3) Ensure the signal conditioners have multiple gain ranges to prevent signal over or under range.

(-4) Use the signal conditioner in accordance with the manufacturer's environmental ratings (remote monitoring location or test enclosures may be necessary).

(c) Noncontacting displacement transducers (or proximity probes) may be used to measure tube motion in the tube bundle periphery. Locate such transducers at the point of maximum displacement as determined by calculation or measurement. Select a noncontacting displacement transducer as determined by the following:

(1) Ensure that the transducer is rated for the temperature, chemistry, radiation, and humidity (or pressure, if underwater) condition to be encountered in testing.

(2) Ensure that the transducer is calibrated (or compensation curves provided) for the tube (target) material.

(3) Ensure that the transducer tip size is such that the eddy field is primarily unaffected by lateral tube motion and tube geometry.

(4) Ensure that the transducer design is such that the eddy field is unaffected by tubes adjacent to the target tube.

(5) Ensure that the transducer design permits use without modifying the heat exchanger tube properties being evaluated.

Use two noncontacting displacement transducers separated by a known angle and targeted on the same tube so that the orbital tube motion can be determined. Mount the transducer so that heat exchanger components other than the targeted tube do not influence the measurement.

Adequately restrain the transducer cable to prevent failure due to flow turbulence if encountered and to prevent heat exchanger damage if fluid flow is present.

Power the noncontacting transducer, and condition the signal as recommended by the manufacturer.

7.1.4 Data Acquisition. Details of data acquisition and reduction can be found in the reference in section 3 (see para. 7.1.5). A summary of guidelines to be observed is provided here.

In comprehensive or complex tests, record the data for off-line analysis. If analog tape recorders are used, the recorders shall be Inter-Range Instrumentation Group (IRIG) compatible, with a 1 in. (25.4 mm) tape recommended. Record the data in either FM (frequency-modulated) Wide-Band Group I or Intermediate Band. Select the recording speed 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 $1.1F_{\max}$ and F_{NY} [see para. 7.1.5(c)].

Check the operability and calibrations of the tape recorder prior to use. Completely and accurately enter all pertinent information (signal recorded, data track designations, signal conditioner gain, tape speed, tape count, etc.) 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.

Avoid signal gain changes during recording sets. Interruption of data recording is suggested if a signal gain is changed. Further, a voice log is suggested to 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 section 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 be either 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 section 3, this can be estimated by

$$B_e \leq 2/\pi \xi_n f_n \left[(1+p)^2 - 1 \right]^{1/2} \quad (1)$$

where

B_e = frequency resolution

f_n = estimated modal frequency

p = acceptable fractional deviation from the true value (e.g., $p = 0.2$)

ξ_n = estimated damping ratio

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:

$$T = \frac{1}{\epsilon^2 B_e} \quad (2)$$

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, 1,024, 2,048, etc.

(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 anti-aliasing 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 anti-aliasing 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 $1.1F_{\max}$ 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 are 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 of this Part.

The Owner shall establish acceptance criteria 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 of this Part. 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 of this Part.

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 may 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

Insert the microphone into or place the microphone 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 Process the time histories 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 gener-

alized 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 of this Part.

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, with regard to 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 handheld 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. Consider the following factors 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.

Consider the following 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.

Take data 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. Ensure that such conditions are covered by the test matrix.

9 DOCUMENTATION

Document the flow conditions and all significant process parameters for the test. Direct measurements of shell-side flow and/or pressure drop across the shell are preferred. Use of pump head characteristics and valve positions should be validated and carefully documented where the preferred conditions cannot be achieved. Flow rates may be calculated using some of these characteristics.

Document the tube vibration level evaluation performed in accordance with para. 10(c).

10 PRECAUTIONS

Observe the following precautions during the planning and execution of heat exchanger vibration measurement programs:

(a) Take adequate precautions to ensure the safety of personnel associated with the test or near the equipment during all phases of the program.

(b) Install and remove instrumentation and other test hardware in accordance with all applicable codes and standards for the equipment being tested.

(c) Review tube vibration levels at each flow rate plateau. Determine the acceptability of the collected data before proceeding to higher flow rates.

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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 A-2(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 Figure A-1, where one can see the small-amplitude response at low flow rates and can identify a threshold flow rate [in this case, $\sim 1,950$ gal/min ($442.8 \text{ m}^3/\text{h}$)] 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 gal/min to 2,400 gal/min ($499.6 \text{ m}^3/\text{h}$ to $545.0 \text{ m}^3/\text{h}$). 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 fluidelastic 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 experienced at subcritical flow rates. See Figures 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