UNITED STATES
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

Before Administrative Judges:

Alex S. Karlin, Chairman
Dr. Richard E. Wardwell
Dr. William H. Reed

In the Matter of	)	
	)	
ENTERGY NUCLEAR VERMONT YANKEE, LLC	)	**Docket No. 50-271-LR**
and ENTERGY NUCLEAR OPERATIONS, INC.	)	**ASLBP No. 06-849-03-LR**
	)	
(Vermont Yankee Nuclear Power Station)	)	

NEW ENGLAND COALITION, INC.

CONTENTIONS 4

PREFILED EXHIBITS

NEC-UW_12 – NEC-UW_22

April 28, 2008

Volume 3

Title: **Flow Accelerated Corrosion Program**

Procedure Owner:	Oscar Limpias / Vice President Engineering (Print Name / Title)	
Approved:	(Procedure Owner Signature)	3/09/06 (Date)

Effective Date				Effective Date Exception				
	EN Common	☐			ANO		PNPS	
	ENN	☒	3/15/06		ECH		RBS	
	ENS	☐			GGNS		VY	
					IPEC		W3	
					JAF		WPO	

Procedure Contains NMM REFLIB Forms: YES ☐ NO ☐

Basis Statement

Re-defined Significant wall thinning
Deleted superseded procedure ENN-DC-133 from text and replaced with ENN-CS-S-008.
Added EPRI CHUG position Paper No.4 to references
Added "CHECWORKS Steam /Feedwater Application, Guidelines for Plant Modeling and Evaluation of Component Inspection Data to references.
Added Passport to text in section 4.4.11.
Added "degraded and deficient" components to text of section 4.4.16
Added threshold for generating condition reports to section 5.11.3
Added "except as provided below" and "Reference section 5.12.2" to section 5.12.1.
Added text "and it is determined that sample expansion" to section 5.12.2.
Added "deficient" to section 5.13.1
Edited various typos to section 8.
Edited logic diagram in attachment 9.3.
Re-indexed section 5.2 to 5.17
Add VY to ENN Fleet procedure.

This procedure supersedes the following site procedures:
- **ENN DC-315 Rev.0**
- **VY – PP7028**

Site and NMM Procedures Canceled or Superseded By This Revision

ENN-DC-315 Rev.0

Process Applicability Exclusion (ENN-LI-100) / Programmatic Exclusion (ENS-LI-101)

All Sites: ☐ Specific Sites: ANO ☐ GGNS ☐ IPEC ☐ JAF ☐ PNPS ☐ RBS ☐ VY ☐ W3 ☐

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1.0 PURPOSE

[1] The purpose of this procedure is to provide requirements for establishing and maintaining an effective Flow Accelerated Corrosion (FAC) Program that will standardize Entergy Nuclear Northeast Fleet's approach towards mitigating FAC damage.

[2] This procedure uses a systematic approach for long term monitoring to enhance the reliability of the affected FAC components by reducing the probability of failures and reduces maintenance costs associated with unplanned or unnecessary repairs.

[3] This procedure provides criteria and methodology for selecting components for inspection, performing inspections, gridding, evaluating inspection data, disposition of results, sample expansion requirements, piping repair /replacement criteria, program responsibilities and documentation requirements.

[4] This program is applicable to plant piping systems and feed water heater shells susceptible to FAC.

[5] This procedure may be used a guide for evaluating systems and components that don't meet the criteria of the FAC program.

2.0 REFERENCES

[1] NRC Generic Letter 89-08, Erosion/Corrosion Induced Pipe Wall Thinning.

[2] NUREG-1344, "Erosion/Corrosion-Induced Pipe Wall Thinning in U.S. Nuclear Power Plants."

[3] NSAC 202L, latest revision, EPRI Document, "Recommendations for an Effective Flow Accelerated Corrosion Program"

[4] EPRI Technical Report, TR-106611, "Flow-Accelerated Corrosion in Power Plants"

[5] NRC Bulletin No. 87-01, "Pipe Wall Thinning."

[6] ENN-LI-102, "Corrective Action Process."

[7] EPRI CHECWORKS FAC Application User's Guide/ CHECWORKS computer models.

[8] ENN-NDE-9.05,"Ultrasonic Thickness measurement"

[9] ANSI B31.1 "Power Piping", (For applicable code year see individual plant FSAR).

[10] ENN-DC-126, "Calculations".

[11] ENN-CS-S-008, "Pipe Wall Thinning Structural Evaluation".

[12] Site ASME XI Repair / Replacement Program as applicable.

[13] ENN-EP-S-005 "Flow Accelerated Corrosion Component Scanning and Gridding Standard".

[14] EPRI Report, "Single-Phase Erosion/Corrosion of Carbon Steel Piping", February 1987.

[15] EPRI Report - "Practical Consideration for the Repair of Piping Systems Damaged by Erosion/Corrosion", dated 10/5/87

[16] NRC Generic Letter 90-05, "Guidance for Performing Temporary Non-Code Repairs of ASME Code Class 1, 2 &3 Piping".

[17] INPO SOER 87-3, "Piping Failures in High-Energy Systems Due to Erosion/Corrosion", March 1987.

[18] INPO Significant Operating Experience Report (SOER) 82-11, "Erosion of Steam Piping and Resulting Failure", February 1982.

[19] EPRI CHUG Position Paper #3, "A Summary of Tasks and Resources Required to Implement an Effective Flow Accelerated Corrosion Program."

[20] Entergy Quality Assurance Manual

[21] ENN FAC Qualification Card ENN-TK-ESPG-042, "Implementing the Flow Accelerated Corrosion Program ".

[22] JAF-SPEC-MISC-03290 Rev.0, "Specification for Evaluation and Acceptance of Local Areas of material, parts and components that are less than the specified thickness." By REEDY Engineering.

[23] IP3-SPEC-UNSPEC-02996 Rev.0, "Specification for Evaluation and Acceptance of Local Areas of material, parts and components that are less than the specified thickness." By REEDY Engineering.

[24] EPRI CHUG Position Paper No. 4, "Recommendations for Inspecting Feedwater Heater Shells for Flow Accelerated Corrosion Damage", February 2000.

[25] "CHECWORKS Steam /Feedwater Application, Guidelines for Plant Modeling and Evaluation of Component Inspection Data", EPRI No. 1009599, Final Report, September 2004.

3.0 DEFINITIONS

[1] Base Line Inspection – An initial wall thickness measurement of a component taken prior to being placed in service.

[2] Basis Document - Program documents that define the scope, attributes, commitments, evaluation reports and predictive models that forms the basis of the FAC program (i.e., System Susceptibility Evaluation reports). These documents contain the basis for the plant piping in the CHECWORKS model, the susceptible-not-modeled (SNM) piping and those that are non-susceptible.

[3] EPRI CHUG – EPRI CHECWORKS USERS GROUP.

[4] Code Minimum Thickness (Tmin) – The minimum required global wall thickness based on hoop stress.

[5] Critical Thickness (Tcrit) - The minimum required wall thickness per code of construction required to meet all design-loading conditions.

[6] Deficient Component - A component identified by examination to be below Taccpt wall thickness or projected to be below Taccpt wall thickness by the next refueling outage.

[7] Degraded component – A component identified as being below the screening criteria that is acceptable for continued operation.

[8] Examination - Denotes the performance of all visual observation and nondestructive testing, such as radiography, ultrasonic, eddy current, liquid penetrant and magnetic particle methods.

[9] Examination Checklist/ Traveler – A data sheet developed for the components being inspected and may contain but is not limited to the following: Tnom, Tmeas, Tmin, Screening criteria, components name, system number, previous data, inspection datasheet number, grid size, examination extent, work order and affiliated minimum wall calculation.

[10] Flow Accelerated Corrosion (FAC) - Degradation and consequent wall thinning of a component by a dissolution phenomenon, which is affected by variables such as temperature, steam quality, steam/fluid velocity, water chemistry, component material composition and component geometry. Previously known as Erosion/Corrosion.

[11] Grid - A pattern of points or lines on a piping component, where UT thickness measurements will be made. Grid may be permanently marked with circumferential and longitudinal grid lines.

[12] Grid Point – A Specific location on a piping component, where a UT thickness measurement will be made. Grid points are at the intersections of the circumferential and longitudinal grid lines.

[13] Grid Point Reading – UT reading taken at the intersection of the grid location.

[14] Grid Scan– 100% scan of the area between the grid lines. The lowest measurement in each area to be recorded as the measured thickness.

[15] Grid Size - The distance between grid points in the circumferential or longitudinal direction. Also called grid space or grid spacing.

[16] Initial Thickness (Tinit): The thickness determined by ultrasonic examination prior to the component being placed into service (baseline) or the first ultrasonic examination during its service life. If an examination has not previously been performed on the component, the initial thickness shall be determined by reviewing the initial ultrasonic data for that component. The area of maximum wall thickness within the same region as the worn area shall be identified and compared to Tnom. If the thickness is greater than Tnom, the maximum wall thickness within that region shall be used as Tinit. If that thickness is less than Tnom, Tnom shall be used as Tinit. Initial thickness for pipe may also be calculated as the nominal thickness multiplied by a factor of 1.125 (1.125*Tnom) for conservatism.

[17] Inspection Location - A specific component (i.e., elbow, tee, reducer, straight pipe section).

[18] Inspection Outage - the outage during which the component was inspected.

[19] Large-bore Piping - Piping generally greater than 2" nominal pipe size with butt-weld fittings.

[20] Line Scans– piping segments broken into one-foot lengths (Small-Bore pipe).

[21] Minimum acceptable wall thickness (Taccpt) – Maximum value of Tmin or Tcrit.

[22] Minimum Measured Thickness - (Tmeas or Tmm) as identified by ultrasonic thickness examination, the present thickness at the thinnest point on a component.

[23] Minimum required thickness – (Taloc) Minimum required pipe wall thickness for internal pressure based on local thinning requirements.

[24] Next Scheduled Inspection (NSI) -The outage at which an inspection will be performed on a given component.

[25] Nominal Thickness (Tnom) - Wall thickness equal to ANSI standard thickness.

[26] PASS 1 Analysis - Runs modeled in CHECWORKS that either have no inspection data, an insufficient number of inspections to provide a proper calibration, or where there is no expectation of ever developing a proper calibration.

[27] PASS 2 Analysis - The process of utilizing UT inspection data thickness measurements in CHECWORKS to predict wear and wear rates for components.

[28] Piping Segment - A run of piping that consists of inspection locations which have common operating parameters (i.e., temperature, pressure, flow rate, Oxygen content and pH level).

[29] Predicted Thickness (tp, Tpred) -The calculated thickness of a component based upon a rate of wear to some point in time (e.g., next refueling, next scheduled examination).

[30] Quadrant Scan– Piping segments divided in quadrants A, B, C, D that are 90 degrees apart and broken into one-foot lengths, or as specified by the FAC engineer.

[31] Qualified FAC Engineer- Individual who has completed the FAC Qualification Card, who participates in the Engineering Support Personnel (ESP) training program and demonstrates knowledge required for the use of the CHECWORKS computer program.

[32] Reference Point - The point on a piping component where the longitudinal and circumferential grid lines originate.

[33] Remaining Service Life (RSL) - The amount of time remaining based upon an established rate of wear at which the component is anticipated to thin to Taccpt.

[34] Safety Factor – A Margin of Safety used to account for inaccuracies in wear rate evaluation.

[35] Sample Expansion - The addition of inspection locations based on significant or unexpected wall thinning during planned inspection(s).

[36] Significant wall thinning - Wall thinning to a thickness less than 60% of pipe nominal wall thickness or wall thinning to a thickness that is half the remaining margin of the piping /component which is above Taccpt. [½ (0.875Tnom + Taccept)] or (Taccpt + 0.020) which ever is greater.

[37] Small-bore Piping - Piping that is generally 2" or less nominal diameter and that typically uses socket welded fittings.

[38] Subsequent Inspection - Inspection of components that have had a baseline inspection and/or an initial operational inspection.

[39] Susceptible Line - Piping determined to be susceptible to FAC using the EPRI susceptibility criteria in NSAC 202L, industry experience and as documented in the System Susceptible Evaluation.

[40] Susceptible Non-Modeled (SNM) Piping - A subset of the FAC susceptible lines that cannot be modeled using the EPRI CHECWORKS software.

[41] Time - Time in service shall be actual hours on line or of operation and/ or hours critical. Calendar hours may be used for conservatism.

[42] UT Datasheets - Paperwork that documents the results of the ultrasonic thickness inspections.

[43] Wear (W) - The amount of material removed or lost from a components wall thickness since baseline or subsequent to being placed in service.

[44] Wear Rate (WR) - Wall loss per unit time.

4.0 RESPONSIBILITIES

4.1 MANAGER, ENGINEERING PROGRAMS (ENNE FLEET PROGRAM OVERSIGHT)

[1] Providing a single point of accountability and is responsible for the overall health and direction of the FAC programs.

[2] Ensuring that the ENN FAC programs are effectively developed and implemented.

[3] Providing oversight for implementing the FAC programs.

[4] Co-ordinate FAC working group meetings.

[5] Co-ordinate ENN FAC Self-Assessments.

4.2 SUPERVISOR, CODE PROGRAMS

[1] Designate responsible engineer/Personnel from the Code Programs Engineering Group for the implementation and maintenance of the Flow Accelerated Corrosion Program.

[2] Ensure that the Flow Accelerated Corrosion Program activities are conducted in accordance with this procedure.

[3] Shall ensure that repair procedures are in place to support any planned repairs or replacements.

[4] Ensure audits and surveillance of selected Flow Accelerated Corrosion (FAC) activities are performed to verify compliance with applicable codes, procedures and drawings.

[5] Provides personnel to perform NDE during normal plant operation and unscheduled outages.

[6] Shall provide qualified Non-Destructive Examination personnel to perform flow accelerated corrosion inspections during scheduled refueling and maintenance outages.

[7] Provides personnel to perform reviews of all final FAC UT data sheets.

[8] Provides personnel to review vendor procedures, personnel certifications and equipment certifications.

[9] Assuring adequate technical personnel are available to provide required support services prior to the outage.

4.3 NDE LEVEL III OR DESIGNEE

[1] Reviews and approves FAC personnel and equipment certifications, and NDE procedures including revisions.

[2] NDE Level II or Level III reviews and signs all final FAC UT data sheets to ensure appropriate NDE examinations have been completed in accordance with the FAC program. The NDE level III review of Risk Informed examination shall be performed in accordance with the site ISI program requirements.

[3] Resolution of anomalies found in inspection data.

[4] Identify discrepancies or deficiencies and initiates condition report in accordance with FAC program or site protocols as appropriate.

[5] Performs oversight of selected FAC examinations to verify vendor procedure compliance.

[6] Performs functions in accordance with applicable procedures including the Entergy Quality Assurance Program.

4.4 FLOW ACCELERATED CORROSION ENGINEER

[1] Shall determine scope of inspections. The FAC Engineer shall develop a list of components/piping segments to be inspected prior to each outage using the criteria of NSAC-202L and CHECWORKS Pass1 and Pass 2 output as a guide. Previous

outage inspection results shall be reviewed prior to development of the inspection list. This list shall be based on the susceptibility to flow accelerated corrosion and the severities of wear identified from previous inspection results.

[2] Review and/or perform an engineering evaluation for all Flow Accelerated Corrosion inspections where pipe wall thinning has been identified and concur on any recommended action. Calculations shall be done in accordance with ENN-DC-126 & ENN-CS-S-008.

[3] Shall ensure that appropriate inspections are performed in accordance with the scope of the Flow Accelerated Corrosion Program.

[4] Shall review and may sign all inspection data and make recommendations for repair/replacement of piping materials in accordance with applicable site protocols.

[5] Shall provide NDE data for review and signature to the ANII, if requested by the ANII.

[6] Shall provide Risk Informed Inspection to the ANII for review and signature, if applicable.

[7] Develops or reviews program basis documents.

[8] Shall revise and/or expand the scope of the Flow Accelerated Corrosion inspection program to incorporate industry and in-house experiences and track/trend inspection results.

[9] Shall maintain records of all inspection results and inspection database.

[10] Develop a FAC examination checklist/traveler that contains Tnom, screening criteria, Taccpt, line number, etc. for the components being inspected.

[11] Shall initiate request for engineering services in accordance with the MAXIMO/PASSPORT or site specific work control system for piping replacement or engineering evaluations as required. This request should include recommended materials for replacement and configuration changes, if applicable, to reduce the effects of flow accelerated corrosion.

[12] The FAC Engineer shall periodically review completed plant modifications to assess their effect on the scope of the flow accelerated corrosion program.

[13] The FAC Engineer shall assist in vendor oversight as required.

[14] Maintaining control of the predictive models (CHECWORKS), which includes any development, updates or revisions to the models.

[15] Developing, revising, and issuing FAC program documents.

[16] Initiating and/or responding to Condition Reports and Engineering Requests for evaluating degraded and deficient components or other discrepancies or deficiencies within the scope of the FAC program.

[17] Developing post outage inspection summary reports.

[18] Review and disposition Operating Event (OE) notices for applicability to the FAC program.

[19] Analyzing inspection data to determine component acceptability for continued service and to determine the need for sample expansion.

[20] Prioritizing and ranking inspection in terms of susceptibility and consequence of failure.

[21] Develop and maintain the System Susceptibility Evaluation report.

4.5 DESIGN ENGINEERING/RESPONSIBLE ENGINEER

[1] Provide minimum acceptable wall thickness (Taccpt) to the FAC Engineer. Responsibility may be delegated to another department or qualified personnel.

[2] Perform local wall thinning evaluations for components having UT measurements that are below or are projected to go below the minimum acceptable wall thickness (Taccpt) or administrative wall thickness requirement.

[3] Prepare and issue engineering response packages for component requiring replacement. Responsibility may be delegated to another department or qualified personnel.

[4] Perform remaining service life evaluation for components in the FAC program as required.

4.6 MAINTENANCE SUPERVISOR/DESIGNEE

[1] The maintenance supervisor or designee will ensure that adequate craft personnel are available to support the FAC program. The supervisor shall ensure that scaffolding is erected, when needed, and insulation removed from components/piping segments that will be inspected and that the piping is prepared for inspection. Scaffolding erection in safety related areas should be in accordance with site procedures.

[2] The maintenance supervisor or designee shall inform the FAC engineer when it is necessary to remove a pipe support for inspection. An engineering evaluation is required if a pipe support requires removal.

[3] The maintenance supervisor must ensure that surfaces to be inspected are free from all foreign materials that would interfere with the inspections, i.e., dirt, rust, paint, etc. If cleaning is required, this may be accomplished by power sanding, flapper wheel only) hand wire brushing, or hand sanding in accordance with site procedures/protocols.

[4] The maintenance supervisor shall ensure restoration of lines, i.e. insulation replaced, scaffolding removed, upon completion of the FAC inspection.

4.7 FAC INSPECTION COORDINATOR

[1] A FAC coordinator may be chosen to Implement the activities of the inspection plan, the duties may include but is not limited to the following activities:

(a) Performing component walk downs

(b) Generating NDE inspection packages

(c) Defining NDE staffing as required

(d) Scheduling of inspections

(e) Acquiring data as required

(f) Providing field coordination to ensure timely inspection are accomplished

(g) Tracking progress of the FAC inspection project

(h) Transmitting inspection results to the FAC Engineer

5.0 DETAILS

5.1 PRECAUTIONS AND LIMITATIONS

None.

5.2 ANALYSIS/PRE-EXAMINATION

[1] The criteria contained in NSAC-202L, latest revision, shall be used to perform the System Susceptibility Evaluation (SSE).

[2] The System Susceptibility Evaluation report shall be developed and peer checked in accordance with ENN procedures.

[3] Non-typical operation of systems should be taken into consideration and if necessary factored into the FAC program.

[4] The susceptible small-bore piping inspection priority ranking should consider personnel safety, consequence of failure and plant unavailability.

[5] Industry and plant experiences relating to FAC will be factored into the program.

[6] The CHECWORKS model should be used for guidance in determining inspection priority based on relative ranking for specific locations to be examined for FAC damage.

5.3 PREPARATION OF OUTAGE INSPECTION PLAN

[1] The FAC Program Engineer shall prepare an Outage Inspection Plan prior to the outage to meet site milestones.

[2] The Outage Inspection Plan should consider the cost of repair/replacement versus inspection.

[3] The Outage Inspection Plan should consider inspection priority based on relative ranking for specific locations to be examined for FAC damage.

[4] Each identified location shall be documented in the inspection plan, along with the component number and reason for selection.

[5] The inspection plan shall be reviewed.

[6] Component Selection

(a) The FAC engineer shall prepare a FAC Outage Inspection scope as directed by plant milestones or as directed by Station management.

(b) Inspection selections shall be made in accordance with the requirements of this procedure and shall be identified based on CHECWORKS results, industry/station/utility experience, required re-inspections, the non- modeled program piping and engineering judgment.

(c) If a selected inspection location is determined to be excessively difficult, impractical or costly to examine due to inaccessibility, temperature, ALARA concerns, scaffolding requirements, or other factors, then an equivalent alternate inspection location may be selected.

(d) Components selected shall be formally documented.

(e) The criteria for component selection should consider the following:

(1) Components selected from measured or apparent wear found in previous inspection results.

(2) Components ranked high for susceptibility from current CHECWORKS evaluation.

(3) Components identified by industry events/experience via the Nuclear Network or through the EPRI CHUG.

(4) Components selected to calibrate the CHECWORKS models.

(5) Components subjected to off normal flow conditions. Primarily isolated lines to the condenser in which leakage is indicated from the turbine performance monitoring system.

(6) Engineering judgment / Other

(7) Piping identified from Work Orders (malfunctioning equipment, leaking valves, etc.).

(8) Susceptible piping locations (groups of components) contained in the Small Bore Piping database, which have not received an initial inspection.

(9) Piping identified from Condition Reports/ Corrective action, Work Orders (malfunctioning equip, leaking valves, etc.).

(10) Feed water Heater Shells

[7] Inspection schedule

(a) Inspection sequence and schedule should be developed based on priority established by the FAC engineer considering repair/scope expansion potential. Consideration will also be incorporated based on other outage work priorities, job conflict and system window duration.

(b) The FAC outage schedule should contain sufficient time for analysis and evaluations of the components being inspected.

[8] Drawing Preparation

(a) For each component scheduled for inspection, an isometric or other acceptable location drawing should be prepared prior to the outage that identifies the component to be examined. When applicable ensure the component number is shown on the drawing.

[9] Obtain Minimum Acceptable Wall Thickness (Taccpt)

(a) Obtain Taccpt (maximum of Tmin or Tcrit) values for each component to be inspected. Those values may be obtained as required, prior to or during an outage.

(b) These criteria may be obtained from engineering calculations or by other approved methods.

[10] Component Identification

(a) Inspected components should have a unique identifier to allow for the tracking of inspection data.

(b) Component identifiers may allow for the identification of the Unit, system, sub-system, line number and corresponding location of that component within a sub-system.

(c) Components in the CHECWORKS non-modeled piping may be identified by using line numbers.

[11] Pre-inspection Activities

(a) Review inspection schedule, inspection requirements and sequence with appropriate plant personnel to ensure requirements for the completion of the FAC inspection are understood.

(b) The FAC engineer should participate in the preparation of FAC inspection work packages as required.

5.4 GRIDDING

[1] Gridding of components shall be performed in accordance with recommendation of NSAC 202L, ENN-EP-S-005 or as specified by the FAC engineer.

[2] Gridding information shall be documented on the appropriate NDE UT data sheet; a sketch may also be required.

5.5 NDE TEST METHODS AND DOCUMENTATION

[1] Components can be inspected for FAC wear using ultrasonic testing (UT), radiography testing (RT), visual observation or other approved methods.

[2] UT thickness measurement is the primary method of determining pipe wall thickness.

(a) Inspections will be performed by using one of the following techniques:

(1) Grid Point Reading

(2) Grid Scan

(3) Quadrant Scan

(4) Line Scan

[3] Ultrasonic Thickness measurement shall be performed in accordance with ENN-NDE-9.05 or other approved site or vendor procedures.

[4] UT Data sheets

(a) A data sheet for components inspected shall be prepared. The information included in the sheet should contain but is not limited to the following:

(1) Plant's name/unit

(2) Components name

(3) Component sketch

(4) NDE technician signature/ date

(5) Grid size

(6) Axial and radial grid boundaries

(7) Calibration information

(8) Level II or Level III signature/date

(9) Work order information

(10) Nominal & Measured thickness

(11) 87.5% nominal thickness screening criteria

(12) Scanning method

5.6 EVALUATION OF UT INSPECTION DATA

NOTE

Historically, typical manufacturing practice has been to supply fittings (especially tees, elbows and reducers) with wall thickness significantly larger than the piping nominal thickness.

[1] The data review should consider screening for further evaluation. Factors that should be considered when reviewing the inspection data include unknown initial thickness (especially fittings), counter-bore, obstructions, and manufacturing wall thickness variations.

[2] For each component that is examined and is below the screening criteria of 87.5% of nominal wall, the wear, wear rate, remaining service life shall be calculated.

[3] The FAC Program Engineer or designee shall review the UT data to ensure that the data is complete and corresponds to the requirements specified on the inspection data sheet (i.e., grid size, spacing, flow direction, starting and ending locations, obstructions, missing data, suspect readings and orientation).

[4] If low readings are determined from repeat inspections that are due to counter-bore, then those areas shall be noted and additional inspections are not required.

[5] Grid Refinement

(a) A grid reduction / refinement may used if the minimum measured thickness is less than the minimum required wall thickness, severe wall thinning is detected, engineering judgment, or the projected thickness is less than the minimum required wall thickness or as directed by the FAC engineer.

(b) The results of the grid refinement or scan shall be documented on an inspection data sheet.

[6] Grid Extension

(a) If measurement indicates wall loss at either edge of the grid, then the grid should be extended until the entire wear pattern is mapped.

[7] Determination of Initial Wall Thickness

(a) For fittings, the band, area and blanket methods calculate wear. Initial Thickness (Tinit): The thickness determined by ultrasonic examination prior to the component being placed into service (baseline) or the first ultrasonic examination during its service life. If an examination has not previously been performed on the component, the initial thickness shall be determined by reviewing the initial ultrasonic data for that component. The area of maximum wall thickness within the same region as the worn area shall be identified and compared to Tnom. If the thickness is greater than Tnom, the maximum wall thickness within that region shall be used as Tinit. If that thickness is less than Tnom, Tnom shall be used as Tinit.

(b) Initial thickness for pipe may be calculated as the nominal thickness multiplied by a factor of 1.125 (1.125Tnom) for conservatism.

[8] Determination of Wear

(a) Wear of piping components may be evaluated using the band, area, blanket or point-to-point method as defined in NSAC-202L, latest revision.

(b) Evaluation of inspection data that is determined to require wear evaluation shall be documented and reviewed.

[9] Wear rate Determination

(a) Wear rate is determined by wear/ unit time (Units to be consistent with thickness evaluation).

(b) A reasonable safety factor may be applied to the wear rates to account for inaccuracies in the FAC wear rate calculations.

(c) Wear rate evaluation should be evaluated on a component evaluation sheet.

[10] Predicted Thickness (tp, Tpred)

(a) The projected or predicted thickness to the next schedule refueling outage.

$$Tpred = Tmeas - \text{Safety factor} \times \text{Wear Rate} \times \text{Time}$$

A safety factor of 1.1 may be applied to ENN plants. If a value other 1.1 is used the reason shall be documented.

[11] Determination of Remaining Service Life (RSL)

(a) Remaining service life (RSL) shall be evaluated as follows, units to be consistent with thickness evaluation:

$$RSL = (Tmeas - Taccpt) / (\text{Safety Factor} \times \text{Wear Rate})$$

5.7 EVALUATION OF RT INSPECTION DATA

[1] Qualified NDE personnel shall interpret the film and report the examination result to the FAC engineer.

[2] Appropriate conservatism should be used to determine if a component requires replacement or re-inspection as a consequence of qualitative nature of RT.

[3] RT inspection shall be recorded on a data sheet.

5.8 EVALUATION OF VISUAL INSPECTION DATA

[1] Where accessible, visual inspections may be performed on two-phase flow lines.

[2] Follow-up UT inspection is required for locations showing evidence of extensive wear.

[3] Due to the qualitative nature of visual inspections, appropriate conservatism should be used when determining whether a component is acceptable to return to service and when establishing a re-inspection frequency.

5.9 DISPOSITION OF INSPECTION RESULTS

[1] The following are used to disposition component inspection results. Reference attachment 9.3 for logic diagram

NOTE

Certain components may have very little margin remaining as a consequence of high stresses in the line even though Tpred ≥ 0.875Tnom and therefore may require evaluation, for example Feedwater, Condensate, RHR, etc.

[2] If Tpred ≥ 0.875 Tnom the component is acceptable as is and may be returned to service.

[3] If Tpred is ≤ 0.875 Tnom Evaluate for sample expansion (Reference section 5.12).

[4] If Tpred ≤ 0.3 Tnom for safety related piping repair or replacement is required.

[5] If Tpred < 0.2 Tnom, for non-safety related, repair, replace or evaluate as warranted.

[6] If Tpred ≥ Taccpt the component is acceptable for continued operations, however monitoring is required.

[7] Tpred is <Taccpt a structural evaluation per ENN-CS-S-008 is required, also a sample expansion evaluation is required or repair or replace in accordance with the requirements of ASME Section XI Repair and Replacement Program.

[8] If Tmeas is <Taccpt a structural evaluation per ENN-CS-S-008 is required.

5.10 RE-INSPECTION REQUIREMENT

[1] If the remaining service life of a component is greater than or equal to the number of hours in the next operating cycle, then the component may be returned to service.

[2] If the component's remaining life is greater than the number of hours in the next operating cycle but is less than the number of hours in the next two operating cycles, then the component should be considered for re-inspection, repair or replacement during the next scheduled outage.

[3] If the component is acceptable for continued service, then it shall be re-examined before or during the outage immediately prior to the cycle during which it is projected to wear to the minimum allowable wall thickness.

5.11 COMPONENTS FAILING TO MEET INITIAL SCREENING CRITERIA

[1] If the results of the remaining life evaluation are shorter than the amount of time until the next scheduled inspection, there are several options for disposition of the component, as follows:

(a) Shorten the inspection interval (for components that can be inspected online)

(b) Refine the Taccpt value through a detailed stress analysis, which should be provided by Design Engineering.

(c) Repair or replace the component

(d) Safety class components that are less than or equal to 0.3Tnom must be replaced or further structural evaluation is required.

[2] Wall thinning resulting in less than Taccpt shall be reported immediately to the FAC engineer by verbal or written communications.

[3] A condition report shall be generated when significant wall thinning or unexpected wear is detected in a system or component.

[4] A condition report shall be generated for wall thinning below Taccpt or other site established limit and a subsequent structural evaluation performed to disposition the line for continued service.

[5] If a previous condition report was generated for a component with wall thinning then no new condition report is required provided that the associated structural evaluation is current and applicable.

5.12 SAMPLE EXPANSION

[1] If a component is discovered that has a current or projected wall thickness less than the minimum acceptable wall thickness (Taccpt), then additional inspections of identical or similar piping components in a parallel or alternate train shall be performed to bound the extent of thinning except as provided below. Reference section 5.12.2

[2] When inspections of components detects significant wall thinning and it is determined that sample expansion is required, the sample size for that line should be increased to include the following:

(a) Components within two diameters downstream of the component displaying significant wear or within two diameters upstream if the component is an expander or expanding elbow.

(b) A minimum of the next two most susceptible components from the relative wear ranking in the same train as the piping component displaying significant wall thinning.

(c) Corresponding components in each other train of a multi-train line with a configuration similar to that of the piping component displaying significant wall thinning.

[3] If the expanded inspection scope detects additional degradation, the sample expansion should continue until no additional components with significant wear are detected.

[4] Sample expansion is not required if the thinning was expected or if the thinning is unique to that component (e.g., degradation downstream of a leaking valve).

[5] Inspections of components from the current or past outages may satisfy the sample expansion criteria, therefore, some of the sample expansion requirements can be met without performing additional inspections.

[6] Sample expansion is not required for components that are being re-inspected if normal or expected wear is detected or wear unique to that component. All other wear patterns encountered shall be evaluated by the FAC Engineer to determine if sample expansion is required.

5.13 REPAIR / REPLACEMENT OF DEGRADED COMPONENTS

[1] The FAC engineer shall generate applicable documents to facilitate repair or replacement of degraded or deficient components.

[2] Components experiencing severe or unacceptable wear should be replaced with corrosion resistant material. However like in kind may be appropriate if procurement of a resistant material would delay plant restart.

[3] Replacing fitting-by-fitting that have experienced significant wear is a satisfactory approach to reducing wear if the wear is very localized (i.e., wear is concentrated downstream of a flow control valve or orifice).

[4] Repairs and replacements to piping and components within the scope of Class 1, 2, 3 shall be performed in accordance with the requirements of ASME Section XI Repair and Replacement Program.

[5] All temporary non-code repairs to ISI Class 1, 2, 3 shall comply with NRC Generic Letter 90-05.

5.14 COMPONENT EVALUATION PACKAGES

[1] The FAC Engineer or designee shall assemble a component evaluation package for each examined component which may contain some of, but is not limited to the following:

(a) UT DATA Sheet

(b) Isometric drawing(s), sketches, flow diagram and digital photo.

(c) Reference to Structural /Minimum wall evaluation

(d) Component evaluation data sheet.

5.15 POST- INSPECTION ACTIVITIES

[1] The FAC Program Engineer shall prepare an Outage Summary report to document the outage FAC activities and submit to Records for retention in accordance with applicable procedures.

[2] Update CHECWORKS models with inspection data.

[3] Update small bore susceptible report as applicable

[4] Update all applicable FAC reports.

[5] Update FAC System Susceptible Report as required.

5.16 LONG TERM STRATEGY

[1] The ENNE long-term strategy for increased safety, reduced costs and reduced FAC rates is accomplished through optimization of the inspection planning process, the use of improved materials for replaced components, improved water chemistry, and appropriate design changes.

5.17 METHODS OF DETERMINING PLANT PERFORMANCE

[1] Program performance indicators, self- assessments and bench marking are utilized as methods for monitoring program and plant performance.

6.0 INTERFACES

[1] ENN-CS-S-008, "Pipe Wall Thinning Structural Evaluation".

[2] ENN-EP-S-005 "Flow Accelerated Corrosion Component Scanning and Gridding Standard".

7.0 RECORDS

[1] Record retention shall be in accordance with site procedures.

8.0 OBLIGATION AND REGULATORY COMMITMENT CROSS-REFERENCES

[1] OBLIGATIONS AND COMMITMENTS IMPLEMENTED OVERALL

Document	Document Section	NMM Procedure Section	Site Applicability
QAPM	A6a, A6b, A6c, A6e	All	All
QAPM	B12a, b, c, d, e,f	All	All
QAPM	B15 a, c	All	All
8.0[1](a)	All		JAF
8.0[1](b)	All	All	JAF
8.0[1](c)	All		IPEC Unit 3
8.0[1](d)	All	All	IPEC Unit 3
8.0[1](e)	All	5.12	All
8.0[1](f)	All		IPEC Unit 2
8.0[1](g)	All	All	Pilgrim
8.0[1](h)	All	All	Vermont Yankee
8.0[1](i)(j)	All		Vermont Yankee

(a) JAFP 87-0737, JAFNPP Docket No. 50-333, Response to NRC IE Bulletin 87-01 Thinning of Pipe Walls in Nuclear Power Plants.

(b) JPN-89-051, JAFNPP Docket No. 50-333. Response to NRC Generic Letter 89-08 Erosion/ Corrosion Induced Pipe Wall Thinning.

(c) IP3-87-055Z, Docket No. 50-286, Response to NRC IE Bulletin 87-01 Thinning of Pipe Walls in Nuclear Power Plants.

(d) IPN-89-044, Docket No. 50-286. Response to NRC Generic Letter 89-08 Erosion/ Corrosion Induced Pipe Wall Thinning.

(e) NRC Generic Letter 90-05, "Guidance for Performing Temporary Non-Code Repairs of ASME (ISI) Code Class 1, 2, 3 Piping".

(f) Mr. Murray Selman (Con Edison) to Mr. William Russell (NRC) "Response to NRC Bulletin No. 87-01, Letter dated September 11, 1987.

(g) BECo 89-107, Docket 50-293, Response to NRC Generic Letter 89-08 Erosion/ Corrosion Induced Pipe Wall Thinning.

(h) Vermont Yankee letter to USNRC, FVY-89-66, Docket No. 50-271. Vermont Yankee Response to NRC Generic Letter 89-08," Erosion/ Corrosion Induced Pipe Wall Thinning", Dated July14, 1989.

(i) Vermont Yankee letter to USNRC, FVY-87-94, Docket No. 50-271, Response to NRC IE Bulletin 87-01 Thinning of Pipe Walls in Nuclear Power Plants. Dated September 11, 1987.

(j) Vermont Yankee letter to USNRC, FVY-87-121, Docket No. 50-271, Supplement to Vermont Yankee Response to NRC IE Bulletin 87-01 Thinning of Pipe Walls in Nuclear Power Plants. Dated December 24, 1987.

9.0 ATTACHMENTS

Guidance on Parameters affecting FAC.

Flow Accelerated Corrosion Program Attributes.

Wall Thinning Evaluation Process Map.

GUIDANCE ON PARAMETERS AFFECTING FAC

Listed below are factors to be considered when reviewing work requests, component replacements and modification packages for possible impact on the content of the FAC Program governed by DC-315. All Design Change Packages (DCP's) are required to be evaluated for impact to the FAC Program. This list is not intended to be all-inclusive or to limit the number of items an individual would consider when performing this impact assessment. It is intended as a reasonable list of items to consider for potential program content updates.

1. Water Chemistry. Many water chemistry parameters have been shown to contribute to FAC.

   a. pH Control Amine – pH is the primary chemistry parameter affecting FAC rates in PWRs. However, the amine used to control pH also plays an important role. Amines such as ammonia tend to separate more into the steam phase in two-phase flow conditions, and therefore provide less protection in the drains. Amines such as morpholine and especially ethanolamine have better partitioning characteristics for FAC.

   b. In a BWR, pH has much less of a role since the pH is stable and there are no amine's added to control the pH. FAC rates decrease as pH level increases. FAC rates seem to drop considerably at pH values of greater than 9.3 - 9.5.

   c. Oxygen Content - FAC rates decrease as oxygen concentration increases. Values that typically result in minimum FAC rates are approximately 15 to 20 ppb.

   d. Hydrogen Water Chemistry – BWR Plants that do not have hydrogen addition normally have a main steam oxygen content near 18 ppm. Plants with hydrogen water chemistry typically have an oxygen content from 3 to 12 ppm. This has a potential to impact the corrosion rates in the LP steam systems; mainly the first and second stage reheater drains based on industry experience.

   e. Hydrazine Injection - Hydrazine is added to the feed train of PWRs as an oxygen scavenger and to maintain a reducing environment in the steam generators. From zero to approximately 150 ppb,an increase in hydrazine concentrations seems to increase rates of FAC. Higher concentrations seem to result in no further increase in FAC rates. EPRI recommends the use of high levels of hydrazine (>100 ppb) to protect steam generator tubes; however, this can result in accelerated rates of FAC in the feed train. Although CHECWORKS does not currently model high hydrazine conditions, any model updates performed after the release of version 1.0F should carefully consider hydrazine concentrations.

f. Zinc Injection - Industry experience has shown that zinc injection decreases corrosion and FAC wear rates due to the concentration of zinc at the oxide surface. The amount of reduction depends on the amount of zinc at the surface.

2. Piping Geometry - Piping geometry is one of the most important factors in FAC. Generally, geometries that produce the greatest turbulence also produce the highest FAC rates. Listed below are examples of obvious items that should be considered in any assessment:

   a. Addition or replacement of fittings, bends and branch connections.

   b. Like for like replacement of any fitting in a system that is susceptible to FAC damage or is part of system that is already part of the FAC Program.

   c. Alterations or repairs encountered in the nozzles or walls of FW heaters, MSR, Drain Tanks, FW Pumps, HD Pumps or CD/CB Pumps.

   d. Throttled Valves.

3. Piping Material Composition - Alloying elements improve the resistance of piping systems to FAC. In ascending order of resistance, the following table presents the degree of improvement over carbon steel:

Material	Nominal Composition	Rate (carbon steel) / Rate (alloy)
P11	1.25% Cr, 0.50% Mo	34
P22	2.25% Cr, 1.00% Mo	65
304	18% Cr	>250

4. In-Line Components - Addition or replacement of such components as thermowells, flow elements and pressure-reducing orifices should be evaluated. The local effects caused by these components can generate FAC damage in areas where overall conditions don't indicate the need for inspections.

5. Component Supports - Additions or deletions of components supports which could result in the need for a review of the existing code minimum wall value or a new code minimum wall calculation.

6. Operational Changes - System operational changes such as the normal operation of emergency heater drains, switching of spare components, extended use of normal start-up or by-pass lines, etc.

ATTACHMENT 9.1 GUIDANCE ON PARAMETERS AFFECTING FAC
Sheet 3 of 3

7. Component Replacements – Records should be updated for like for like replacement of fittings already in the program including new baseline data, changing next scheduled inspection due date, etc. Note and track whether the replacement components have had surface preparation and a UT grid applied for future outage planning.

8. External Sources – Information concerning FAC Inspection results from other stations and Nuclear Plants operated by others. General information distributed by EPRI Reports, INPO & NRC Bulletins, etc. should also be considered.

9. Maintenance History – A review of the maintenance performed on valves, orifices, steam traps, etc. should be considered. Valves that have had seat leakage can cause very localized wear in systems normally exempted. Plugged traps create water pockets in steam systems that accelerate metal loss. Eroded orifices can cause increased metal loss due to decrease in back pressure and increase in flow rates.

ATTACHMENT 9.2 FLOW ACCELERATED CORROSION PROGRAM ATTRIBUTES
Sheet 1 of 1

PROGRAM ATTRIBUTES

Attributes:

Program Infrastructure

(a) Program Structure: Roles & Responsibilities, Program Ownership, Organizational Interfaces, etc.
(b) Flow Accelerated Corrosion Program Document.
(c) Flow Accelerated Corrosion System Susceptibility Review, Latest Revision.
(d) Report(s) Summarizing the Augmented portion of the FAC Inspection program, Latest Revision.
(e) CHECWORKS models

Program Staffing and Experience

(a) Background and Expertise.
(b) Qualification and training.
(c) Bench Strength.
(d) Industry Participation.

Program Implementation

(a) Inspections
(b) Maintenance and Repairs
(c) Control of Changes and Deferrals
(d) Review of INPO Operating Experience documents, CHUG operating experience, NRC notices.

Health Monitoring:

(f) System Engineering Health reports.
(g) FAC Quarterly Health Reports.

Effective Assessment:

(h) Perform FAC Self-Assessment on a periodic basis or as defined by applicable procedures.

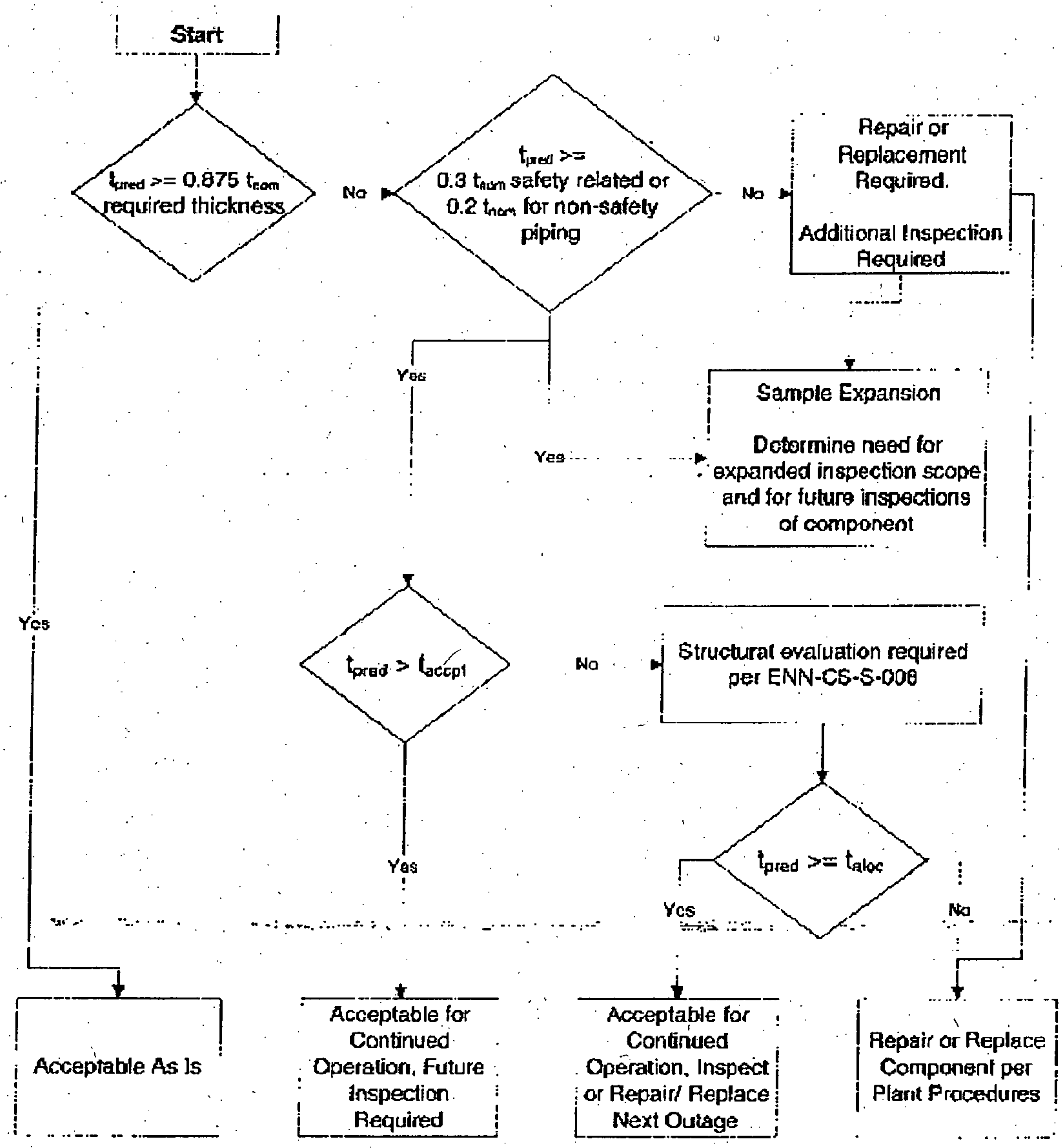
Oversight:

(k) Effective assessment, Benchmarking or Audits.

ATTACHMENT 9.3 WALL THINNING EVALUATION PROCESS MAP

Sheet 1 of 1

Logic Diagram - Evaluation of Pipe Wall Thinning



Chockie Group International, Inc.

Aging Management and Life Extension in the US Nuclear Power Industry

October 2006

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Executive Summary

All systems and equipment degrade over time. However, the nature and the rate of degradation depend on such factors as the design, material, construction, mode of operation, and operating environment. With effective inspection and maintenance practices aging degradation can be managed and operational life can be extended well beyond what was originally planned. For over 25 years the United States (US) nuclear power industry and the US Nuclear Regulatory Commission (USNRC) have worked together to develop aging management programs that ensure the plants can be operated safely well beyond their original design life.

This report was prepared by the Chockie Group International to provide an overview of the aging management and life extension programs and regulations within the US commercial nuclear power industry and their possible applicability to the petroleum industry in Norway. It was prepared as part of the project for the Petroleum Safety Authority (PSA) Norway entitled, *Design Life Extension Regulations* (PSA Project Reference Number: NO 99B16).

Associated with this report are two companion briefing reports that provide focused examinations of two important aspects of life extension requirements. These are *Performance Monitoring of Systems and Active Components* (CGI Report 06.21) – an examination of the Maintenance Rule requirements for effective maintenance programs, and *Condition Monitoring of Passive Structures and Components* (CGI Report 06.22) – a review of the License Renewal Rule requirements and process for aging management of passive and long-lived structures and components.

There are three important principles associated with aging management. These are:

- maintaining the structures, systems, and components (SSCs) in "as new" condition – with no reduction in performance or safety margins
- preventing failures of critical SSCs
- understanding and managing the age-related degradation mechanisms

During the operating life of a plant these aging management principles should be an integral part of the maintenance program. However, when contemplating life extension another set of issues must be considered. As the US nuclear industry and the USNRC concluded, in order to extend the operating life beyond the original design life additional economic and technical factors need to be considered.

Although the possibility of life extension for nuclear plants in the US has existed for more than 50 years, the industry and regulator have been actively developing life extension requirements for only the last 25 years. In 1954 the original licensing requirements for US nuclear power plants set a 40-year limit for operating licenses. This 40-year limit was selected based on economic considerations rather than technical limitations. However, even at that time, the Atomic Energy Act was set up to allow renewal of the operating licenses.

In the late 1970s the USNRC and the nuclear industry began to address the issues concerning life extension. The first initiatives were directed at determining whether or not the safe operation of the plant beyond its 40-year operating limit could be technically justified. That is, could the aging effects be adequately managed so the plant could be operated within the original safety margins during the period of extended operation?

To answer this question both the USNRC and the industry initiated a number of aging research programs. One of the largest aging research efforts was the Nuclear Plant Aging Research (NPAR) Program. This 10-year, multi-million dollar effort was sponsored by the USNRC and produced over 150 aging research reports. Other aging research programs by the industry complimented the work of the NPAR program. Based on the results of these programs it was concluded that many aging phenomena are readily manageable and do not pose technical issues that would preclude life extension for nuclear power plants. As long as there are effective inspection and maintenance practices the plant life is simply limited by the economic cost of repair or replacement of any components that do not meet specified acceptance criteria.

The USNRC then moved forward with the development of license renewal requirements and published the initial License Renewal Rule in 1991.

For over fifteen years the USNRC and the nuclear industry have been continuously refining both the license renewal requirements and the renewal process. There are many aspects of these efforts and lessons learned that can be of potential value to the PSA and the Norwegian petroleum industry.

The following are some of the key lessons from the development and implementation of aging management programs and life extension requirements that could be applicable to the PSA and the Norwegian petroleum industry in their consideration of life extension and aging management.

<u>Aging Research Information</u>

The wealth of aging related information produced by the NPAR and industry aging research programs remains a useful resource for both nuclear and non-nuclear organizations. Although the aging studies examined SSCs with respect to their operation in the nuclear plants, much of the aging degradation and aging management information is applicable to the petroleum and other industrial sectors.

<u>Continuous Improvement</u>

Over the years both the USNRC and the industry have been working to make the license renewal requirements and the renewal process more efficient and effective. For example, the initial version of the License Renewal Rule did not provide a predictable nor stable process – it was too open ended and too broad a scope. It was determined that many aging effects were already adequately addressed during the initial operating license period. Also, the initial Rule did not allow sufficient credit for existing programs, particularly those under the USNRC Maintenance Rule, which help manage plant aging phenomena as part of the on-going maintenance program tasks.

The resulting revised Rule established a simpler, more stable, and more predictable regulatory process. The key changes that were made included:

- focusing on the adverse effects of aging rather than identification of all aging mechanisms such that identification of individual aging mechanisms is not required
- simplifying the integrated plant assessment process and making it consistent with the revised focus on the detrimental effects of aging
- adding an evaluation of time-limited aging analyses (TLAA)
- requiring only passive, long-lived structures and components to be subject to an aging management review for license renewal, thus removing active SSCs from license renewal

Passive Versus Active

An important aspect of the US nuclear plant life extension requirements is the distinction between passive and active systems, structures, and components. Passive SSCs are those that do not move to function (such as structures, heat exchangers, cables, valve and pump bodies, and piping). Their age related degradation can only be monitored and trended by performing periodic condition assessments (such as inspections, testing, and measurements).

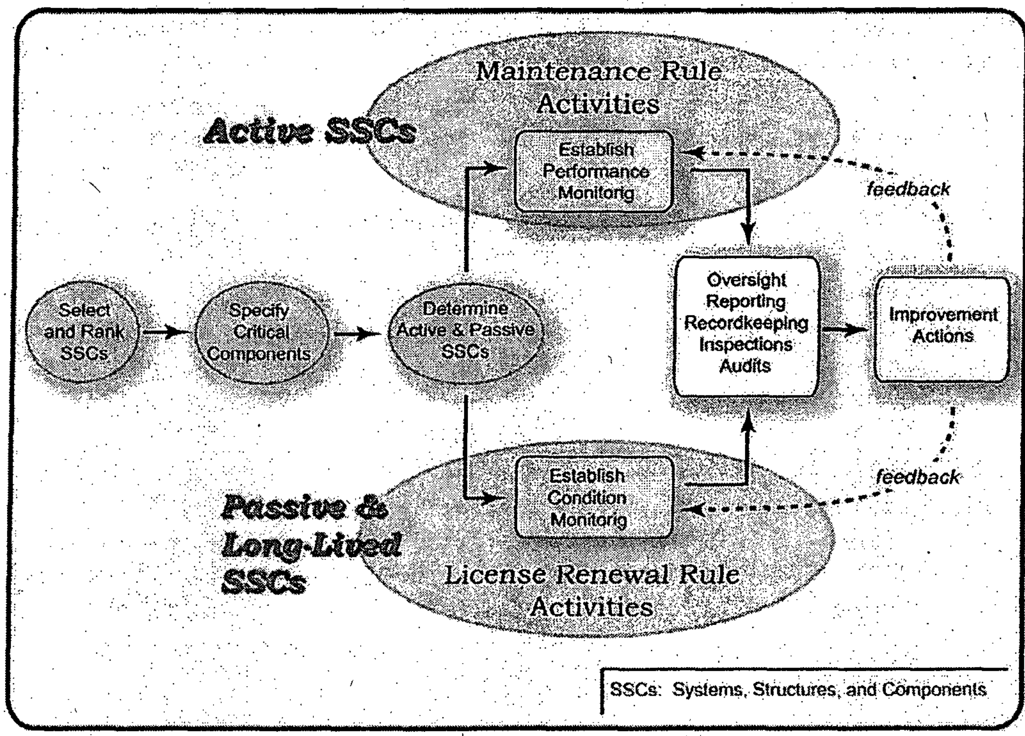
By focusing the license renewal process on safety critical passive and long-lived components the process has been reduced to manageable proportions – licensees are not required to consider all SSCs in order to justify extended operations.

A diagram of the relationship of the License Renewal and Maintenance Rules to the aging management of active and passive SSCs is shown in the figure on the next page.

During the renewal process, the licensee must confirm whether the original design assumptions will continue to be valid throughout the period of extended operation or whether aging effects will be adequately managed. The licensee must demonstrate that the effects of aging will be managed in such a way that the intended functions of passive or long-lived structures and components will be maintained during extended operation.

Need for Guidance

One of the key lessons has been the need to provide clear guidance and support to all involved parties. Both the USNRC and the industry have developed guidance documents to assist in the development of aging management programs, the preparation of the renewal application, and the review of the application. As lessons are learned these guidance documents are revised to capture new insights or address emerging issues. Along with the guidance documents, training programs and support activities have greatly reduced the time and expense in preparing, reviewing, and approving the license renewal applications.



Other Aging Management Lessons Learned

In reviewing the aging management and life extension efforts of the nuclear industry there are several areas where the experiences of the US nuclear power plants and USNRC could be of value to the PSA and the petroleum industry. These include:

- integrating aging management and maintenance requirements – careful management to avoid duplication of effort and non-effective maintenance tasks
- developing a long-term maintenance strategy – linking asset management to maintenance strategy with the objective to preserve the assets as long as economically feasible
- reducing component failures – being proactive to identify incipient failures, precursors, and age related degradation.
- effectiveness of condition monitoring – improving the application of diagnostic analysis to prevent failures
- establishing appropriate inspection procedures
- aging management of inaccessible equipment (since replacement and repair is not usually an economically feasible option)
- sharing experiences by tracking generic failures and monitoring effectiveness of aging management activities
- implementing pilot projects to evaluate the effectiveness of new requirements and processes

- properly quantify consequential failure costs – to support reliable conclusions and to justify implementation of a predictive maintenance and effective aging management strategy

Conclusions

The aging management and life extension process for the US nuclear industry has been refined and improved over the years. It has become an efficient and effective method to ensure that the nuclear plants in the United States can be safely operated beyond their original 40-year operating license. By dividing the safety critical systems, structures, and components into passive and active categories the industry and regulator have reduced the potentially overwhelming analysis effort to a reasonable and manageable size.

By working together, the nuclear industry and the US Nuclear Regulatory Commission (USNRC) have been able to technically justify life extension. The process has been structured to not be an economic or resource burden on either the licensees or the USNRC. However, all parties are continually reviewing the process and results to identify where improvements can be made.

The process has been selected as a viable method by many international regulatory and nuclear industry organizations, including those in Spain, Taiwan, and Korea. The International Atomic Energy Agency in Vienna has also adopted the process as the model for ensuring safe extended life operations.

The aging management and life extension process can be easily adapted to other industries. The development strategy, research material, specific elements of the process, and many of the lessons learned can all be of potential value to the PSA and Norwegian petroleum industry in ensuring safe extended operations of the facilities.

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Aging Management and Life Extension in the US Nuclear Power Industry

Background

This report on aging management and life extension actions within the United States (US) nuclear power industry was prepared by the Chockie Group International as part of the project for the Petroleum Safety Authority (PSA) Norway entitled, *Design Life Extension Regulations* (PSA Project Reference Number: NO 99B16).

Report Objective

The objective of the report is to provide an overview of the development and application of aging management and life extension programs and regulations within the US commercial nuclear power industry.

This report is a companion to two previous briefing reports that the Chockie Group International prepared for the PSA. The first, entitled, *Performance Monitoring of Systems and Active Components* (CGI Report 06.21), examined the requirements and activities associated with aging management of active systems and components. The second briefing report, *Condition Monitoring of Passive Systems, Structures, and Components* (CGI Report 06.22), addressed the programs and regulations for aging management of passive systems, structures and components for extended operation.

Information from these two briefing reports has been incorporated into this overview report.

The Principles of Effective Aging Management

It is a well-established fact that mechanical and electrical equipment can be maintained over long periods of time, using refurbishment, partial/complete replacement and reconditioning. There are some automobiles from the early 1900's that now look better and work better than when they were made. The technology to maintain equipment in an "*as new*" condition is called effective aging management. There are three basic principles that form the foundation of aging management programs.

The first principal is that there can be not reduction in the safety margins over the useful life of the plant. With respect to commercial nuclear power plants, the Nuclear Regulatory Commission (USNRC) does not permit reduction in safety margins. This implies that the plant licensees must maintain the plants in as new condition.

The second major principal is to avoid failures. The reliability of the plant will never be better than its worst performing system or component. To avoid failures, one must have the skills, knowledge, and experience to recognize pending failures and take timely corrective actions for all structures, systems, and components that are critical to the safe operation of the plant.

The third principal is to understand the behavior of materials when exposed to certain stressors (in other words, to understand the applicable aging mechanisms). This knowledge helps focuses attention on the "right places and at the right time". This also provides the information necessary for addressing the aging degradation situation with the right tools and developing effective actions to mitigate or prevent the problem from affecting safe plant operations.

Since the beginning of nuclear power in the US the industry and regulator have embraced these principles and have worked to ensure that the plants are properly maintained and operated over their operating life.

The Push for Life Extension

The operating life of the US plants has been limited to 40-years as is discussed in more detail in the following section. However, almost twenty-five years ago both the industry and the USNRC began to address the possibility of life extension. The first question they need to answer was whether it was technically justifiable and economically feasible to operate the plant beyond the original 40-year limit? If so, then what should the life extension approval process? The results of hundreds of aging research studies and many years of work have convinced all parties that life extension is both economically and technically viable. To ensure that the plants continue to operate within their design safety margins during extended operation, the USNRC in coordination with the nuclear industry had developed an effective and efficient license renewal process. The License Renewal Rule is discussed in detail in the CGI Report 06:22 and is summarized in later sections of this report.

Report Content

The first section of the report provides a brief historical perspective of the rationale for the life extension requirements and how the process has been split along the lines of active and passive systems, structures, and components.

The second section examines the key organizations that have been instrumental in the development of aging management programs. Included is an overview of how the various programs relate and complement each other.

The third section provides a discussion of the principal aging management and life extension program. The following sections examine the two key aging management requirements, the USNRC License Renewal Rule and Maintenance Rule.

The importance of industry developed aging management programs and the support and sponsorship of aging research by both the USNRC and industry is reviewed next. In the following sections a number of relevant issues and activities including early license renewal and international applications are examined.

The last part of the report discusses the lessons that have been learned over the twenty plus years in developing and implementing the aging management and life extension programs and requirements. Also as part of this later section is a summary of information, tools, strategies, and lessons that may be applicable to the PSA and Norwegian petroleum industry – how the PSA and the industry can take advantage of the extensive work and lessons to develop "focused" life extension requirements to ensure that adequate levels of safety are maintained during extended operation.

Historical Perspective

The 40-Year Operating License

When the original licensing requirements for United States commercial nuclear power plants were developed it was agreed to limit the licenses for a 40-year operating period. The 40-year limit was selected based on economic considerations rather than technical limitations.

The 40-year limit was specified by the US Congress in the Atomic Energy Act of 1954. The law was modeled on the Communications Act of 1934. This Act set up the conditions for radio stations to be licensed and operate for several years. Then the stations would be allowed to renew their licenses as long as they continued to meet their charters. Similarly, the Atomic Energy Act allows for the renewal of operating licenses for the nuclear power plants.

Congress selected 40 years for nuclear power plant licenses based on the view that this was the time required to pay off the plant investments through the anticipated income from the electrical rate base. The 40-year license term was not based on safety, technical, or environmental factors.

As specified in the Atomic Energy Act, the plants can reapply for a new operating license after 20-years of operation. If granted, the new license covers the remaining term of the 40-year operation plus up to a 20-year extension. The regulations do not set any limit on the number of renewals that a plant can apply for.

Renewal is voluntary. The decision is primarily economical and whether the licensee believes they can continue to meet NRC requirements. By June 2006, 21 nuclear plants have received regulatory approval for 20-years of extended operation. Another nine plant applications are being reviewed.

The Importance of Passive versus Active

The US Nuclear Regulatory Commission (USNRC) and the nuclear industry have developed a strategy to ensure the extended safe operation of the plants. An important element of the US strategy is the distinction between passive and active systems, structures, and components (SSCs). As a general definition, passive SSCs are those that do not move to function (such as, structures, heat exchangers, transformers, valve and pump bodies, and piping). Their age related degradation can only be monitored and trended by performing periodic condition assessments (such as inspections, testing, and measurements). An aging evaluation is typically required to identify the degradation mechanisms and to select the effective inspections and tests.

In order to ensure that the US nuclear power plants continue to maintain adequate levels of safety during extended operation beyond their original license period the USNRC has developed two important sets of requirements. These are the:

- Maintenance Rule
- License Renewal Rule

The requirements for the aging management of "active" systems and components are addressed by the Maintenance Rule (as discussed in CGI Report 06.21). The aging management of active SSCs should be part of the plant maintenance program. Good maintenance practices should identify and correct any aging degradation issues of the active SCCs and that no special license renewal aging management requirements are necessary for extended operational approval.

The focus of the License Renewal Rule is on the management of aging degradation of safety critical "passive" and long-lived systems, structures, and components (SSCs) at the nuclear power plants (as discussed in CGI Report 06.22). Long-lived items are those that are not subject to replacement based on a qualified life or specified time period.

Copies of the Maintenance Rule and the License Renewal Rule are provided in Appendices A and B, respectively.

Benefits of Life Extension

The industry and government have assessed the potential economic and environmental impact of life extension. Extending the useful plant life by 20 years for the 104 operating US plants is the equivalent of building 52 new plants. It would be most likely that these 52 replacement power plants would be coal fired. The avoidance of harmful plant emissions (SO_x, NO_x, heavy metals, and ash) is a significant environmental accomplishment (see Figure 1). Additionally, life extension is a way of minimizing the current bottleneck for the disposal of used spent fuel. Over the years, there have been numerous delays in the development of a final national repository for spent nuclear fuel. The extension of the operating licenses will allow the plants to continue to store the material on-site until the repository becomes available.

On the economic scale, each plant represents an asset value of between $1 billion to $2 billion.

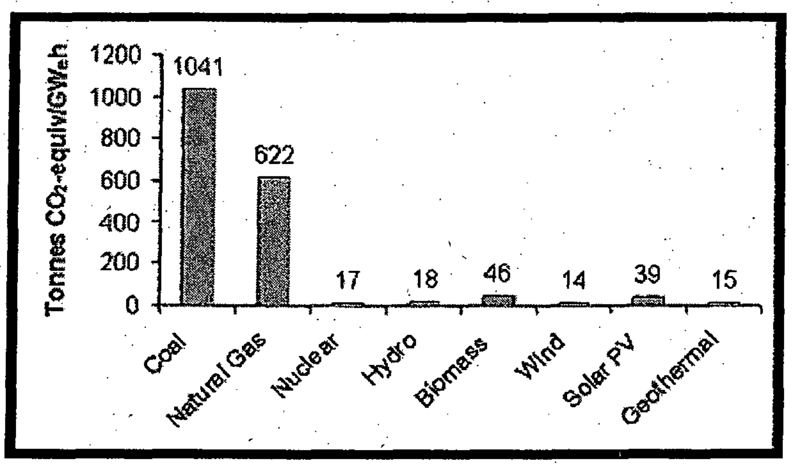


Figure 1: *Comparison of Life-Cycle Emissions*

The largest part of the operating costs comes from the depreciation of the original investment over the first 40 years and the decommissioning fees. After 40 years, the only remaining capital costs are those associated with refurbishment and replacement of aging components. The fuel and operations and maintenance costs are much lower than comparable size coal or oil fired plants. The overall benefit-to-cost ratios are on the order of 2:1 to 4:1 (a saving of between \$500 and \$1000 million) over the period of extended operation. According to the Nuclear Energy Institute:

> *... the economic value of the U.S. nuclear fleet over the remaining 40-year life of the plants is approximately \$65 billion, and, over a 60-year life, assuming license renewal, is \$76 billion. (Economic value is net present value of future revenue stream net of fuel and O&M costs, capital additions, etc., expressed in 2002 dollars.)*

Life extension also brought into focus the value of increasing capacity factors and the possibility of power uprate. Many plants have already completed significant power uprates, gaining 10% to 15% additional capacity with little investment. In fact, the equipment reconditioning and replacements performed as a result of life extension are made to also satisfy the needs of power uprate that is new equipment is purchased with additional capacity or upgraded. Capacity factors for the operating plants have been increasing over the last ten years, mostly by reducing the number of outage days for refueling and avoiding plant shutdowns. The average fleet capacity factor has increased about 10% to the present value of around 90%. The combined effect of power uprate and capacity factor increase has provided the equivalent electric output of about 26 additional nuclear plants. These efforts were made possible by the prospect of life extension and the attendant economic savings.

Because most of the cost of electric production from nuclear plants in the US is regulated at the state level, the net savings by the plant operators are ultimately passed on to the consumer. As a result, the economic benefits from more efficient extended operation should be realized by the utility customers.

Development of Aging Management Programs

This section examines the key organizations that have been involved in the development and improvement of programs to identify and manage the effects of aging on plant systems, structures, and components (SSCs). Also briefly discussed is the relationship among the many industry and regulatory aging management related programs.

Key Organizations Involved in Nuclear Plant Aging Management

There have been a number of industry and governmental organizations involved for over twenty-five years in the development of aging management programs and requirements for the extended operation of US nuclear plants. The key organizations are:

- Industry Organizations
  - Electric Power Research Institute (EPRI)
  - Institute of Nuclear Power Operations (INPO)
  - Nuclear Energy Institute (NEI)
  - Boiling Water Reactor Owners Group
  - Westinghouse Owners Group
  - Babcock and Wilcox Owners Group
  - Combustion Engineering Owners Group
- Governmental Organizations
  - US Department of Energy (DOE)
  - US Nuclear Regulatory Commission (USNRC)

The principal aging related activities of these various organizations are summarized below.

<u>EPRI Aging Research</u>

EPRI, the research arm of the electric utilities, sponsored life extension pilot plant and demonstration projects. These studies provided the initial technical and economic impetus for individual plant owners to look at plant life extension as a serious option for their long-term generation planning. EPRI aging research projects established the basic aging assessment technology and aging management principles. EPRI programs concerning mechanical, electrical, and structural equipment identified potential aging mechanisms and the effects of aging degradation (those that manifest themselves and can be visually or otherwise observed).

EPRI and various nuclear plant owners groups also sponsored the development of Industry Reports on Component Aging. Aging Management Tools for mechanical, electrical and structural equipment were produced to provide guidance to the plant licensees.

A similar effort was undertaken to deal with the aging management of the non-safety related portion of the plant. EPRI initiated the Preventive Maintenance Basis project to develop an industry consensus of best practices for maintenance and aging management. This project was closely followed by the EPRI Life Cycle Management program to create long-term maintenance strategies on the basis of highest reliability at the lowest costs.

INPO Maintenance Management Guidance

Initially there were no uniform implementation procedures for the aging management programs related to non-safety structures, systems, and components (SSCs). INPO lead the development of an equipment reliability guide [AP-913] that incorporating the preventive maintenance (PV) basis, life cycle management (LCM) programs, and reliability centered maintenance (RCM) programs. AP-913 has become the standard to measure plant excellence.

NEI Aging Guidelines

The Nuclear Energy Institute has been responsible for taking the lead in the development of the guidelines to assist licensees prepare the license renewal applications. The NEI-95-10 document, entitled *Industry Guidelines for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule,* provides licensees with an acceptable approach for implementing the requirements of the USNRC License Renewal Rule. This is a living document and is continuously updated based on NEI's monitoring of licensees experiences with the license renewal process. NEI continues to be the focus for interaction between the industry and the USNRC and serves as a spokesperson for the industry when new life extension or aging management issues emerge.

DOE Aging Research

The US Department of Energy (DOE) is responsible for national long-term energy planning. DOE has supported a number of the EPRI programs including those addressing mechanical, electrical, and structural equipment aging degradation. Follow-on research by DOE has included the Aging Management Guides for major components and commodities and the concrete aging research conducted by the DOE Oak Ridge National Laboratory.

USNRC License Renewal Research & Regulations

In the early 1980s the USNRC initiated a major aging research program to investigate the aging degradation of safety related equipment. This program, entitled the Nuclear Plant Aging Research (NPAR) program, examined aging degradation in both passive and active structures, systems, and components. This was a major multi-million dollar research effort lasting almost 10 years and sponsoring more than 100 aging research studies. The Program eventually generated over 150 technical reports.

The findings from the NPAR Program provided the basis for determining that extended operations of the nuclear power plants were technically justifiable. It also provided the foundation for the license renewal requirements and renewal process.

In 1991, the safety requirements for license renewal (entitled, Requirements for Renewal of Operating Licenses for Nuclear Power Plants) were adopted by the USNRC. These requirements, known as the License Renewal Rule, established the procedures, criteria, and standards governing the renewal of nuclear power plant operating licenses. These were made mandatory requirements as part of the United States Code of Federal Regulations (commonly referred to as 10 CFR Part 54).

For the next few years the USNRC in cooperation with the nuclear industry conducted a demonstration program to apply the Rule to pilot plants. The objective was to assess the effectiveness of the requirements and the application/review process. The USNRC also undertook a number of activities related to the implementation of the Rule. These included:

- developing a draft regulatory guide
- developing a draft standard review plan for license renewal
- reviewing generic industry technical aging information

Based on discussions with industry and results from the demonstration program the USNRC determined that revisions to the Rule were needed. The USNRC found that many aging effects are dealt with adequately during the initial license period. In addition, the USNRC found that the review did not allow sufficient credit for existing programs, particularly those under the USNRC Maintenance Rule, which also helps manage plant aging phenomena.

In summary, the amended Rule established a regulatory process that is simpler, more stable, and more predictable than the initial License Renewal Rule. It put the focus of the license renewal assessment on the licensees aging management activities concerning passive and long-lived SSCs. It also clarified the focus on managing the adverse effects of aging rather than identification of all aging mechanisms. The changes to the integrated plant assessment (IPA) process were to make it simpler and more consistent with the revised focus on passive, long-lived structures and components

Relationship of Aging Management Programs

The original life extension pilot plant studies performed in the 1980's did not differentiate among passive and active components or the safety and non-safety related portions of the plant. The focus of these studies was to determine the critical components and life ending scenarios as a result of progressive unmitigated degradation and from this to establish a realistic attainable plant life. When the USNRC started to develop the License Renewal Rule, they had the benefit of the pilot studies results and included the passive and active components within the scope of the Rule. This turned out to be a bad decision, as industry tried to cope with very costly implementation costs and impractical application of the requirements. Because the Maintenance Rule was being prepared by the USNRC in the same timeframe and dealing exclusively with the performance monitoring of active components and systems, the License Renewal Rule was revised to only encompass long-lived passive components and structures. Notably, the USNRC regulations only apply to the regulated safety related portions of the plants, about one-third of the total plant. (A detailed review of the Maintenance Rule is provided in CGI Report 06:21.)

When life extension or license renewal is considered, the entire plant needs to be assessed and prepared to meet its extended life goal. To this end the industry sponsored a number of equipment reliability research studies concerning the aging degradation for the non-safety portions of the plant. The initial focus was the development of Reliability Centered Maintenance (RCM) to identify critical component/parts. It was followed by the Preventive Maintenance Basis (PMB) to collect and document industry "best practices" for the maintenance of equipment. The relationship of the various industry and USNRC programs is shown in Figure 2.

However, the early aging studies and the license renewal efforts quickly pointed to a maintenance gap. Plants did not have, nor were they developing, and long-term aging management programs. As a result, EPRI sponsored the development of a Life Cycle

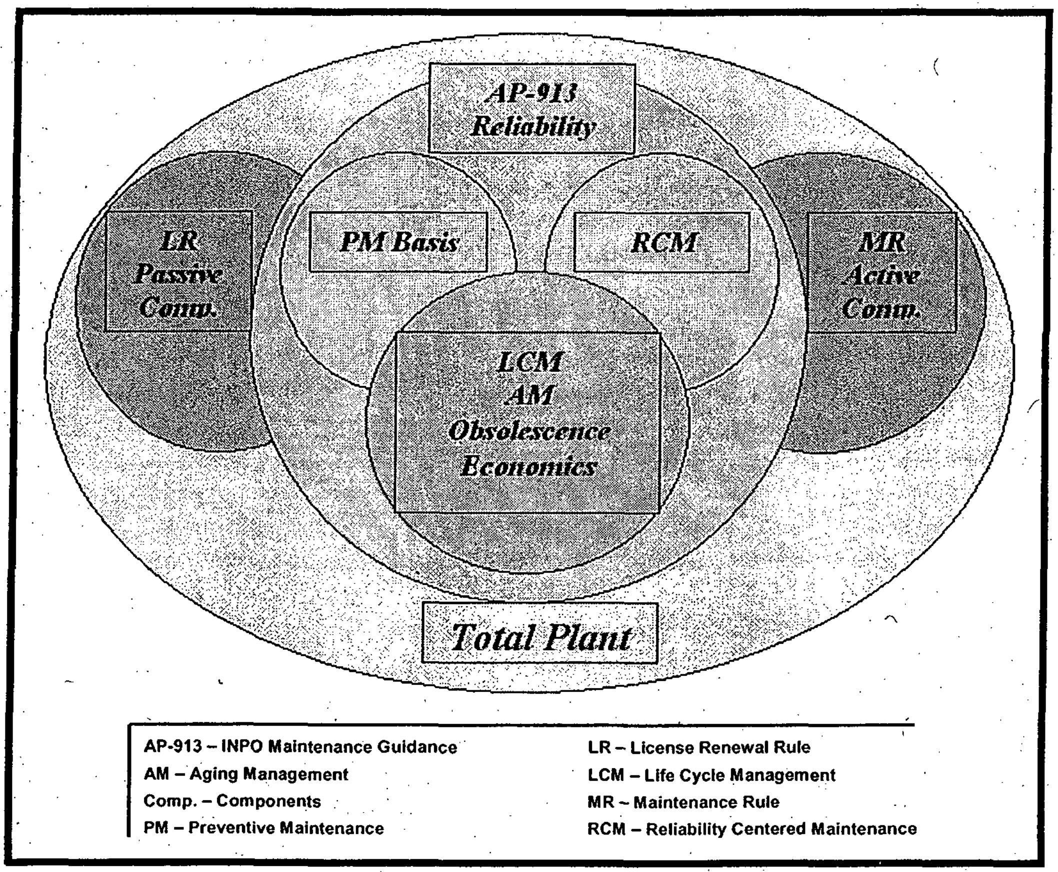


Figure 2: *The Relationship of Aging Management Programs*

Management (LCM) methodology for the plants to use to determine the most effective alternative from a number of scenarios. As defined by AP-913, life cycle management (LCM) is:

> *... the process by which nuclear power plants integrate operations, maintenance, regulatory, environmental, and business activities that manage plant condition (by means of aging and obsolescence management), optimize operating life (including the options of early retirement and license renewal), and maximize plant value while maintaining plant safety.*

LCM can provide a basis for a long-term maintenance strategy with the highest reliability at the least cost. LCM makes use of RCM and PMB in addition to addressing technical obsolescence, aging management and the generic and plant-specific operating experience. The LCM program also considers economics to select the optimum long-term maintenance strategy.

INPO lead the development of the "umbrella" process that incorporates the various maintenance and aging management programs and requirements. This resulting industry guidance document, entitled, *Equipment Reliability Process Description* (AP-913), has become the industry standard by which plant maintenance performance is currently judged.

A related maintenance oversight activity is exercised by the insurance companies, such as Nuclear Equipment Insurance Limited. These insurance companies have created similar maintenance standards to be followed with the objective of minimizing their liability exposure. A benefit-penalty system has been applied by which the insurance premiums are determined based on the level of compliance with their maintenance standards.

The Industry "Umbrella" Program (AP-913)

The *Equipment Reliability Process Description* (AP-913) developed by INPO has become the industry umbrella for effective plant maintenance practices. Many plants have adopted all or portions of AP-913, including the applicable parts of the regulatory programs, such as the aging management and performance monitoring parts of the License Renewal Rule and Maintenance Rule, respectively. It is important to note that the AP-913 is an industry initiative and is not a mandatory requirement. However, INPO's role as an industry oversight organization for utility corporate and plant performance assures that most plants implement part or all of the recommended equipment reliability program guidance.

Large utilities with a substantial number of plants are creating their own organizational standards that essentially mirror the AP-913 program features.

The AP-913 process, as shown in Figure 3, consists of six basic elements. Each element, as briefly described below, has a series of considerations or tasks, which should be part of an effective maintenance program.

Scoping and Identification of Critical Components

There are basically three categories of components within the plant. First, and most important, are the critical components that would shut down the plant or initiate safety

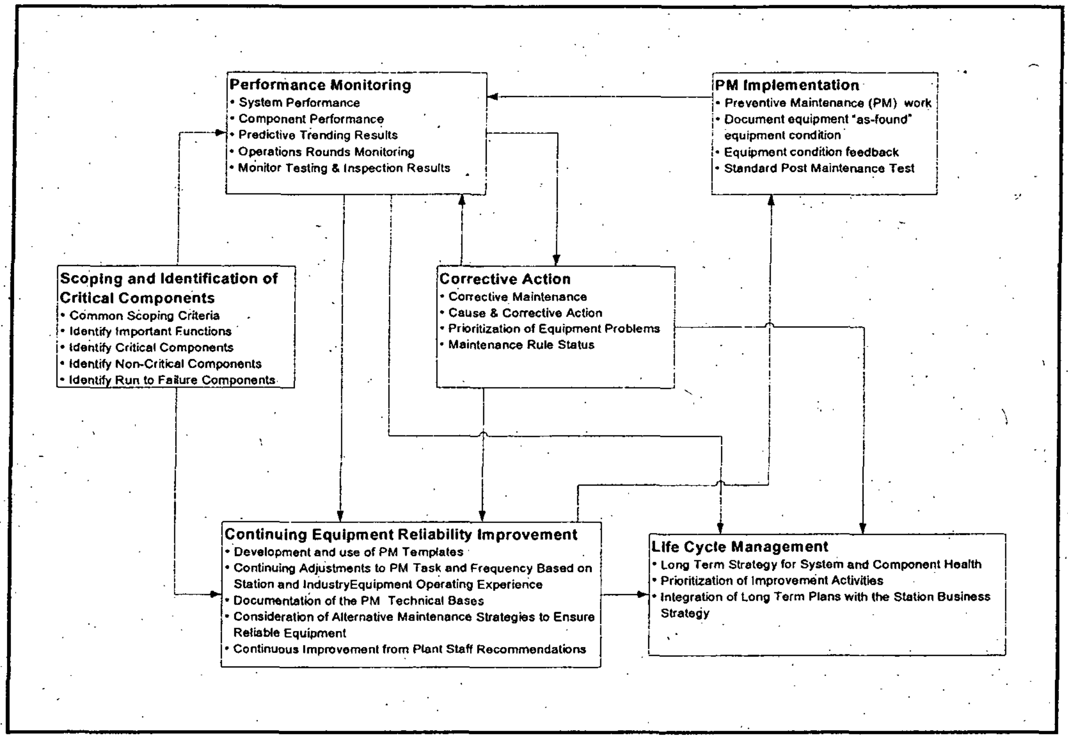


Figure 3: *Equipment Reliability Process (Source: INPO AP-913)*

systems if they were to fail their functions. The second category is the non-critical components that are being maintained by regular or vendor recommended maintenance. The third category is the run-to-failure components for which maintenance is not economically justifiable. These components are replaced on a set time schedule or following their failure.

Performance Monitoring

For the critical and non-critical components, performance monitoring as required by the USNRC Maintenance Rule is applied at the system or component level (reliability and availability). Performance trending is conducted to assure that mitigative or corrective actions are contemplated prior to the component or system exceeding its performance limits.

The routine system of engineer and operator rounds is one example of recommended performance monitoring tasks. The rounds are undertaken frequently (such as daily or weekly) to detect minor changes in equipment behavior. Tasks to be administered during the rounds may include visual observation of the equipment looking for missing/loose parts, leakage, noise, fumes/smell, missing insulation, construction debris, abnormal vibration, discoloration and rusting, deformation, and cracking of foundations. Operators are required to confirm the correct position of breakers and switches, read local instrumentation, and verify position of fire and security barriers/doors.

At the crafts level, a "*condition code*" process has been implemented by most plants to facilitate condition feedback for the equipment being worked on. This condition code typically includes three to five levels of equipment conditions as observed by the maintenance personnel. Typical levels of condition codes may be:

- Condition 1: As New
- Condition 2: Meets or exceeds expectations
- Condition 3: Shows signs of acceptable wear/degradation
- Condition 4: Should be scheduled for overhaul, replacement
- Condition 5: Found in failed condition

These conditions are simple observations and are recorded on a standard form with the work package to be evaluated by the system engineer. A more detailed condition code table, using a 10-point graduation, is included in AP-913 presented in Table 1.

Other recommended considerations for performance monitoring include:

- use of equipment history and the corrective action database to perform equipment failure trending for components used across several systems
- specific alert values for condition-monitoring data in the component performance criteria

Table 1: *Equipment Condition Codes* (Source: AP-913)

CONDITION 1
Unanticipated Failure Failure not associated with normal wear or aging discovered at time of activity Condition Report required to address condition Potentially misapplied structure, system, or component requiring engineering resolution
CONDITION 2
Repair/Replacement Required, Not Necessarily Due to Normal Wear or Aging *Failure not definitely attributable to normal wear or aging; can be repaired with replacement in kind material, parts, or components* May require engineering resolution
CONDITION 3
Repair/Replacement Required, Due to Normal Wear or Aging Failure that is obviously due to normal wear or aging that can be repaired without engineering evaluation Consider performing the PM task more frequently
CONDITION 4
Measured Parameter Outside Specified Tolerance *Component has not failed, but adjustment is required* No replacement parts other than those dictated by the PM task required Consider performing the PM task more frequently
CONDITION 5
Reliability Degraded Component has not failed, but replacement or repairs recommended due to normal wear or aging to ensure reliable operation until the next inspection Consider performing the PM task more frequently
CONDITION 6
Measured Parameter Within Tolerance, but Adjustment Required Adjustments required due to normal wear, aging, or drift No replacement parts other than those dictated by the PM task required
CONDITION 7
Satisfactory *Observed wear considered normal* No adjustments required No replacement parts other than those dictated by the PM task required
CONDITION 8
Superior Observed wear less than would be expected No adjustments required No replacement parts other than those dictated by the PM task required Consider performing the PM task less frequently
CONDITION 9
Like New Component is in "like new" condition Consider performing the PM task less frequently
CONDITION N
As-Found Condition Not Applicable Administrative task One-time performance Condition monitoring task

- trending of as-found equipment condition codes to:
    - identify patterns of degradation by component type and the need to adjust preventive maintenance (PM) tasks or frequencies
    - update PM templates based on station equipment operating experience
    - to identify PM outliers for additional evaluation

- use industry event database (EPIX) to identify component trends being experienced by other plants, and take proactive measures to avoid similar failures
- identify aging or obsolescence issues
- evaluate the relationship between component performance and effect on system functional performance
- trend key data collected on operator rounds
- consult non-nuclear sources of component failure information and trending parameters/strategies

Corrective Actions

This is perhaps the most important element, in that it directs the plant to perform a rigorous root cause evaluation of equipment failure. It also requires management actions to develop a plant culture of preventing future failures. According the AP-913:

> *This is one of the hard links management can establish to reinforce an intolerance for unexpected equipment failures. By establishing management expectations that evaluations of unexpected failures include the question of why the failure occurred and what process should have prevented it, instead of just repairing it, continuous equipment reliability improvement initiatives become a way of life. This is also an opportunity to revisit a previous decision to run to failure.*

An evaluation is required to determine if the failure was preventable, using the following considerations:

- What existing barriers should have prevented the failure (procedure completeness, procedure implementation, craft training, post-maintenance testing, tag-out restoration, use of operating experience, troubleshooting, unavailability management, and human performance)?
- What barriers should be implemented to prevent recurrence? Consider the risk/benefit of the change.
- What other components are susceptible to this failure mechanism; what is the extent of this condition?
- How did the continuing equipment reliability improvement process miss this?
- Could more frequent implementation of existing preventive maintenance actions prevent recurrence?
- Should the scope of the preventive maintenance tasks be increased?
- Is there an aging or obsolescence concern that should be addressed in the corrective actions?
- Is additional corrective maintenance needed?
- Is the failed component in USNRC Maintenance Rule scope or did the failure cause a significant power reduction?
- Provide equipment root cause training and qualification, including the requirement to participate in a certain number of root cause analyses per year.

- Develop root cause specialists or mentors, with additional training and experience, in departments that frequently participate in this activity.
- Use a graduated approach for root cause determination commensurate with the level of consequences of the failure. Examples include trending only, apparent cause determination, root cause determination by an individual, and forming a root cause team.
- Establish clear methods to obtain vendor expertise or increased failure analysis for equipment failures whose root cause cannot be determined by a team.
- Search in-house and industry operating experience, including EPIX, to determine if similar failures have occurred.
- Are similar components affected by the same problem?

Continuing Equipment Reliability Improvement

This element is the focus of the INPO equipment reliability strategy. It is structured to reflect a living maintenance program with continuous feedback, enhancements based on equipment performance, adjustments to PM frequencies to compensate for poor or excellent performance, to look for alternative solutions, recognize application of new technologies/diagnostics and to eliminate low value tasks and/or add new tasks where the need arises. Equipment reliability is tightly coupled to the need to identify incipient failures, monitor failures at other plants and look for precursors. This means that we know the locations, susceptibility to failure and the potential degradation, such that effective monitoring methods can be engaged. This element suggests that the following monitoring methods be considered:

- Degradation can be monitored by installed instrumentation.
- Degradation can be detected by a predictive maintenance technique such as vibration, oil sampling, thermography, or motor signature analysis.
- Degradation can be visibly observed during operator rounds or system engineer walkdowns.
- Degradation can be measured by surveillance testing.

Long-Term Planning and Life-Cycle Management

With the event of power uprate (increasing the power output beyond the design levels, e.g., 115 to 120%) and life extension for the nuclear plants, it became evident that long-term plans needed to be developed to support cost-benefit assessments of these major capital projects and to formulate a lifetime maintenance strategy for the plants. The utilities were used to strategic planning with respect to power need forecasts, selecting the type of power generation and revenue projections, however, the nuclear plants needed a more sophisticated asset management tool, taking into account the unique life cycle and major capital expenditures for these plants. The Life Cycle Management (LCM) methodology and process was developed to fit this gap and was subsequently integrated with AP-913. This integration specifically recognizes the need to merge the long-term maintenance strategy with the station business plan.

Preventive Maintenance Implementation

Lastly the program addresses implementation issues of the equipment reliability process. Plants are expected to have a rigorous work order system by which maintenance activities can be scheduled, implemented and recorded. The work order database provides a historic record of all work performed and includes data fields for the type of activity (preventive, corrective, design change, surveillance testing, operations test, etc) for each component, the date, required hours and in many cases also the labor and material costs. The data such constitutes a significant element for the reliability assessment in that the number of failures (each component and all similar components) can be sorted by year, cost and type, from which failure rates can be computed. Trending of the number of preventive and corrective work orders can be performed to ascertain whether the trend is stagnant, positive or negative. The effectiveness of the maintenance program can therefore be measured over time.

The License Renewal Rule

In 1954 the original licensing requirements for US nuclear power plants set a 40-year limit for operating licenses. This 40-year limit was selected based on economic considerations rather than technical limitations. However, even at that time, the Atomic Energy Act was set up to allow renewal of the operating licenses.

In the late 1970s the USNRC and the nuclear industry began to address the issues concerning life extension. The first initiatives were directed at determining whether or not the safe operation of the plant beyond its 40-year operating limit could be technically justified – could the aging effects be adequately managed so the plant could be operated within the original safety margins during the period of extended operation?

To answer this question both the USNRC and the industry initiated a number of aging research programs. One of the largest aging research efforts was the Nuclear Aging Plant Research (NPAR) Program. This 10-year, multi-million dollar effort provided the basis for determining that extended operations were technically justifiable. It also provided the foundation for the license renewal requirements and renewal process.

The NPAR Program identified aging as the cumulative, time-dependent degradation of a systems, structures, and components (SSCs) that, if unmitigated, could compromise continuing safe operation of the plant. Mitigating measures are therefore needed to ensure that aging does not reduce either the operational readiness of a plant's safety systems or the defense-in-depth through common-mode failures of redundant, safety-related equipment.

The main goals of the NPAR Program were to understand aging and to identify ways to manage aging of safety-related SSCs. The specific technical objectives were to:

- identify and characterize aging effects which, if unmitigated, could cause degradation of SSCs and impact plant safety
- develop supporting data to facilitate management of age-related degradation
- identify methods of inspection, surveillance, and monitoring, or of evaluating residual-life of SSCs, which will ensure timely detection of significant aging effects before loss of safety function
- evaluate the effectiveness of storage, maintenance, repair, and replacement practices in mitigating the effects of aging and diminishing the rate and extent of degradation caused by aging
- provide technical bases and support for the License Renewal Rule and the license renewal process

During the mid-1980s the USNRC initiated two other aging assessment programs as companions to the NPAR Program. One focused on the aging of nuclear plant vessels, piping, steam generators, and nondestructive examination techniques. The other involved the assessment of age-related degradation on plant civil structures. These three programs provided a wealth of information and insights on aging and aging management that formed the basis for the License Renewal Rule.

The NPAR Program alone produced over 150 technical reports and numerous papers and proceedings concerning aging characteristics and aging management of safety-related SSCs. The major subjects examined by the NPAR and related aging research programs are shown in Table 2.

Table 2: *Subjects Examined by the NPAR and Related Aging Research Programs*

Air operated valves	Chillers
Auxiliary feedwater pumps	Heat exchangers
Batteries	Large electric motors
Bistables/switches	Main steam isolation valves
Cables	Motor operated valves
Chargers/inverters	Piping
Check valves	Power operated relief valves
Civil structures	Small electric motors
Circuit breakers/relays	Snubbers
Compressors	Solenoid valves
Connectors, terminal blocks	Steam generators
Diesel generators	Transformers
Electrical penetrations	Vessels

Although the aging studies examined SSCs with respect to their operation in the nuclear plants, much of the aging degradation and aging management information is applicable to the petroleum and other industrial sectors. A list of selected aging reports from the NPAR program is provided in Attachment of the CGI Report 06-22, *Condition Monitoring of Passive Systems, Structures, and Components.*

Based on industry initiatives started in 1985, two pilot plants were chosen to conduct life extension investigations and feasibility assessments. The principal objectives were to find answers to a number of questions, including:

- What defines the ultimate life of a plant?
- What are the events that lead to final plant shutdown?
- What is a realistic and achievable operating life?
- What type of repair and replacement capital projects would be required?
- Are there any technical or economic obstacles or limits?

These studies introduced the concept of "critical components". These are components that if they were allowed to degrade unimpeded would constitute a safety concern and lead to shutdown. An importance ranking process was developed to identify the critical components and perform a relative importance ranking, using a Delphi process. The result was a list of the top 24 components, all passive components and structures. These components were then selected for a detailed aging assessment to investigate the plausible aging mechanisms, identify the associated aging effects that have been observed and to formulate a strategy for effective aging management, using preventive and mitigative maintenance or corrective repair and replacement options. These efforts were later extended to cover a host of other components and commodities, including active components, to create a more complete picture of the plant's aging concerns.

While the studies for the two pilot plants were carried out by completely separate research teams, the results and conclusions were very similar. A byproduct of the pilot studies were the identification of a host of additional aging research tasks, a need to better understand certain aging phenomena, the recognition that aging management needs to start at the beginning of the life cycle and the need to perform some maintenance tasks to better monitor material conditions, such as inspections, tests, fatigue cycle counting, measuring environmental conditions in electrical enclosures, testing soil and water for aggressiveness (chlorides, phosphates, pH) with respect to concrete and instituting structures inspections.

A technical review group examined the aging research findings and concluded that many aging phenomena are readily manageable and do not pose technical issues that would preclude life extension for nuclear power plants. They also stated that as long as there are effective inspection and maintenance practices, the plant life is simply limited by the economic cost of repair or replacement of any components that don't meet specified acceptance criteria.

With the technical and economic feasibility of life extension demonstrated, the industry started working with the USNRC to develop a License Renewal Rule that would provide a formal process to allow extended operation beyond the original 40-year license.

In 1991, the safety requirements for license renewal (entitled, *Requirements for Renewal of Operating Licenses for Nuclear Power Plants)* were adopted by the USNRC. These requirements, known as the License Renewal Rule, established the procedures, criteria, and standards governing the renewal of nuclear power plant operating licenses. These were made mandatory requirements as part of the United States Code of Federal Regulations (commonly referred to as 10 CFR Part 54).

The scope of this initial version of the Rule included both passive and active components for the safety related systems of the plant.

Revisions to the Rule – Lessons Learned

Again, the Monticello plant volunteered to be the demonstration plant to test the Rule. The objective was to assess the effectiveness of the requirements and the application and review process. Once completed, it became apparent that the provisions of the original Rule required changing – particularly the requirements for commitments and additional maintenance tasks to be implemented. Cost estimates ranged from to $100 to $500 Million for a plant to comply with rule requirements.

The Rule did not allow sufficient credit for existing programs, particularly those under the USNRC Maintenance Rule, which help manage plant aging phenomena on an on-going basis. The initial License Renewal Rule also did not provide a predictable nor stable process. Industry point out, and the USNRC agreed, that it is essential to have a predictable and stable regulatory process that clearly and unequivocally defines the regulatory expectations for license renewal.

The revised Rule was published in 1995. A copy is provided in Appendix B. The new amended Rule established a regulatory process that is simpler, more stable, and more predictable. It put the focus of the license renewal assessment on the licensees aging management activities concerning passive and long-lived SSCs. It also clarified the focus on managing the adverse effects of aging rather than identification of all aging mechanisms. The changes to the integrated plant assessment (IPA) process were to make it simpler and more consistent with the revised focus on passive, long-lived systems, structures and components.[1]

The relationship of the regulatory requirements for the Maintenance and License Renewal Rules is shown in Figure 4.

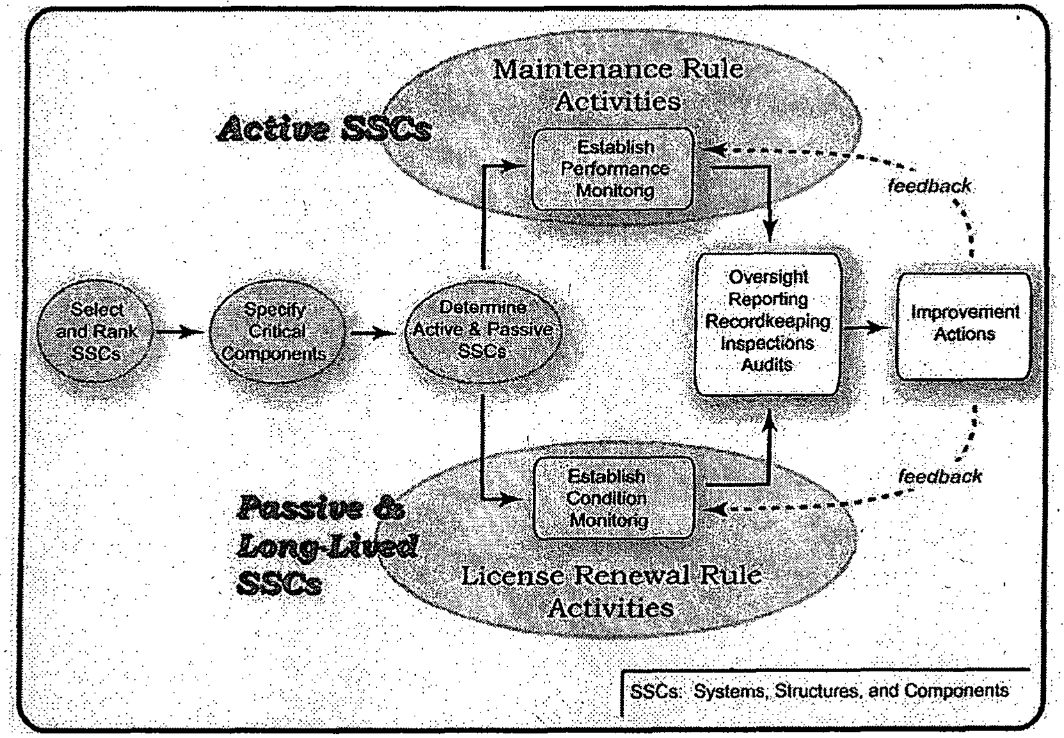


Figure 4: *Relationship of Maintenance and License Renewal Rules*

The License Renewal Process

The license renewal process proceeds along two tracks – one for the review of safety issues and another for environmental issues. The safety requirements, as noted above,

[1] An extensive discussion of the revisions and the USNRC's license renewal philosophy can be found in the Statement of Considerations that accompanied the License Renewal Rule as published in the US Federal Register, Vol. 60, No. 88, page 22461, May 8, 1995.

are addressed in 10 CFR Part 54. The environmental requirements are found in 10 CFR Part 51.

The USNRC developed a generic environmental impact statement (GEIS) which covered impacts that were common to most all nuclear power plants. During the review process the USNRC focuses on the important environmental issues specific to each plant.

The license renewal review process (Figure 5) is intended to identify any additional actions that will be needed to maintain the functionality of the SSCs for the extended operation. The USNRC determined that the following can be <u>excluded</u> from the license renewal aging management review:

- those structures and components that perform active functions
- structures and components that are replaced based on qualified life or specified time period.

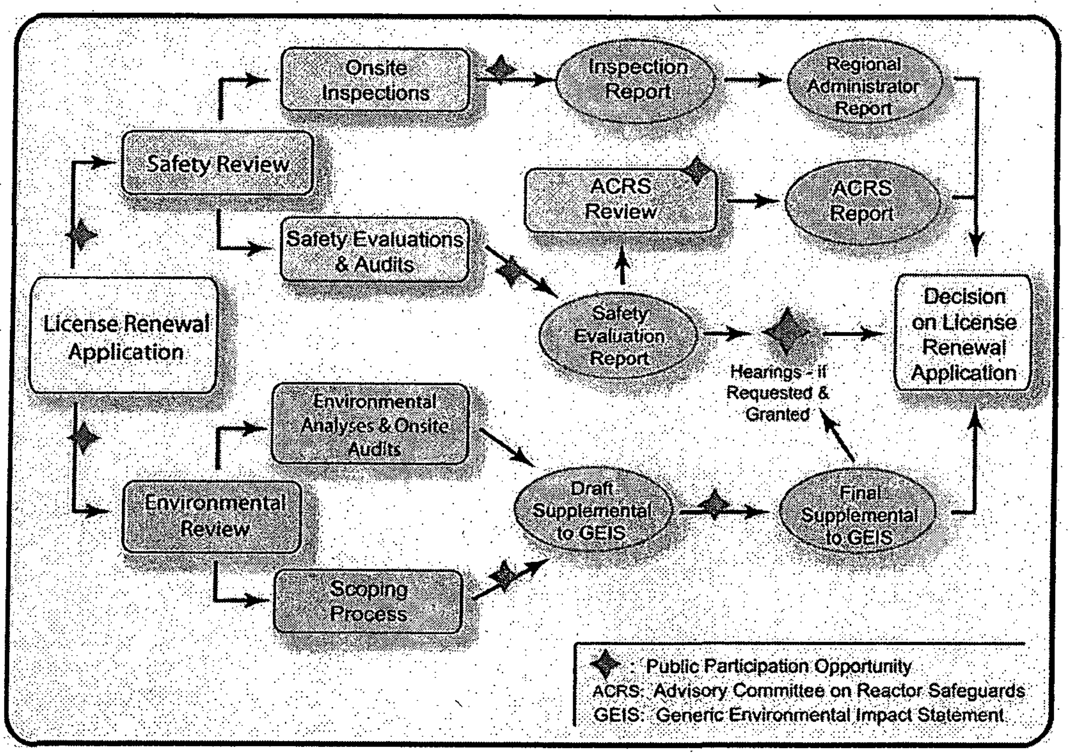


Figure 5: *Simplified Flow Chart of the License Renewal Process (source: USNRC)*

License Renewal Principles

The license renewal requirements for nuclear power plants are based on two key principles:

- the existing USNRC regulatory process (such as the Maintenance Rule) is adequate to ensure that currently operating plants will continue to maintain adequate levels of safety during extended operation – however, license renewal requirements are needed to address age-related degradation unique to life extension for certain passive and long-lived SSCs as well as a few other issues that may arise during the period of extended operation

- each plant's licensing basis is required to be maintained during the renewal term in the same manner and to the same extent as during the original licensing term

The License Renewal Application

Two important items that are required to be included in the application are:

- an integrated plant assessment
- an evaluation of time-limited aging analyses

The application development process involves the following actions:

- identification of the SSCs within the scope of License Renewal Rule
- identification of the intended functions of SSCs
- identification of the structures and components subject to aging management review and intended functions
- assurance that effects of aging are managed
- development and application of new aging management programs and inspections
- identification and resolution of time-limited aging analyses
- identification and evaluation of exemptions containing time-limited aging analyses

Scoping

The scoping phase requires the licensee to identify all plant systems, structures and components that are safety-related or whose failure could affect safety-related functions, or that are relied on to demonstrate compliance with the several specific USNRC's regulations (such as, for fire protection and plant blackout).

The scoping or categorization process can be rather complicated and requires careful review of the nature and function of the various SSCs being considered. For example in the case of valves and pumps, the valve bodies and pump casings may perform an intended function by maintaining the pressure-retaining boundary and therefore would be subject to aging management review.

Integrated Plant Assessment (IPA)

The integrated plant assessment (IPA) is the core of the license renewal application (Figure 6). The purpose of the IPA is to demonstrate that the structures and components requiring aging management (within the scope of the Rule) have been identified and the effects of aging on their functionality will be managed to maintain an acceptable level of safety during extended operations

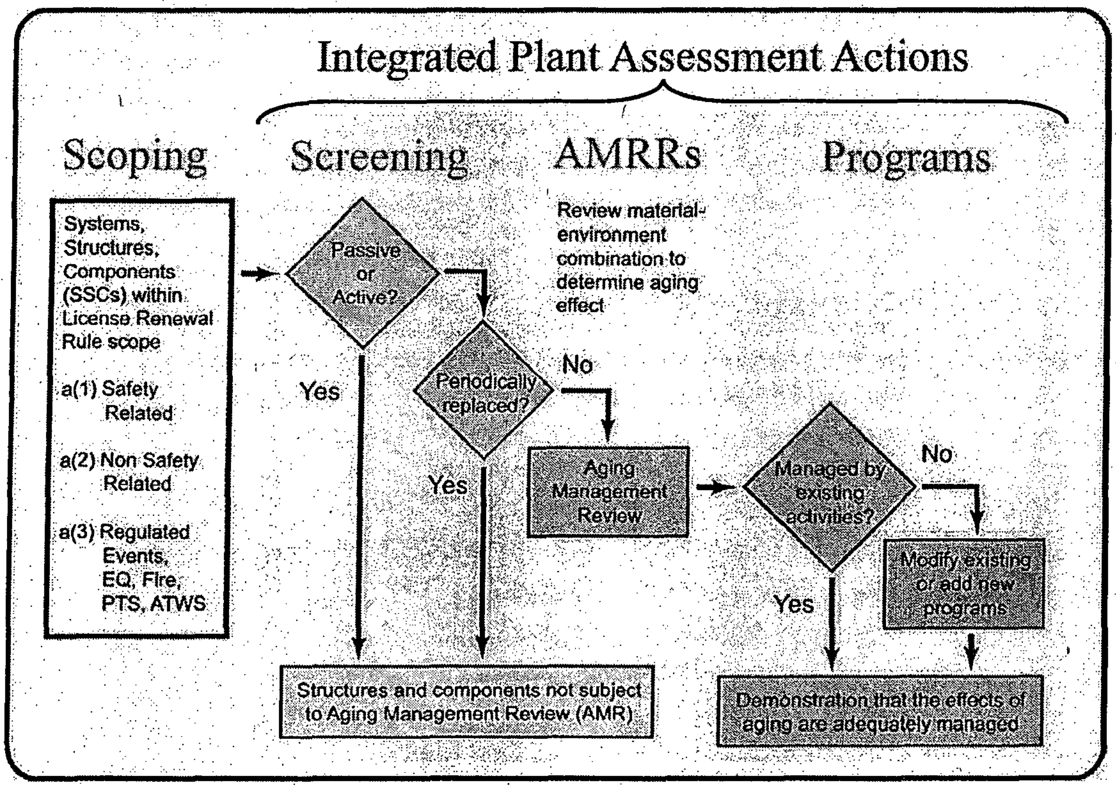


Figure 6: *License Renewal Application Activities*

The first part of the IPA process is to determine which of the structures and components within the scope of the Rule are passive and long-lived. Passive structures and components are those that perform their function without a change in configuration or properties. Long-lived items are those that are not subject to replacement based on a qualified life or specified time period. An example list of such structures and components is provided in Table 3.

The objective of this screening exercise is to determine which components and structures require aging management review to determine whether or not some form of aging management is necessary.

There are a number of different techniques that can be used to identify and assess aging effects. The NEI guidance document (NEI 95-10) lists several approved techniques. These include material-environment-stressors analysis, analysis based on common setting or location, plant specific aging analysis based on loss of intended function, and the use of similar aging management reviews approved by the USNRC.

The licensee must demonstrate that the effects of aging will be managed in such a way that the intended functions will be maintained for the extended operation period. Where the licensee can demonstrate that the existing programs provide adequate aging management throughout the period of extended operation, no additional action may be required. However, if additional aging management activities are warranted, it will be up to the licensee to define these actions. This can include such activities as developing new monitoring programs or increasing current inspections. Licensees should consider all programs and activities associated with the component or structure to determine to what degree they already manage the aging degradation. The four general types of aging management programs are:

- Prevention – to preclude certain levels of aging degradation from occurring (e.g., coating programs to prevent external corrosion of a tank)
- Mitigation – to reduce or slow aging effects (e.g., chemistry programs to mitigate internal corrosion of piping)
- Condition monitoring – to inspect for the presence of and extent of aging effects (e.g., visual inspection of concrete structures for cracking and ultrasonic measurement of pipe wall for erosion-corrosion induced wall thinning
- Performance monitoring – to test the ability to perform its function (e.g., heat balances on heat exchangers for the heat transfer intended function of the tubes)

Table 3: *Examples of Structures and Components included in, or excluded from, the License Renewal Rule Scope* (Source: 10 CFR 54)

Passive Structures & Components Included in Rule Scope (Example List)	Active Structures & Components Excluded from Rule Scope (Example List)
cable trays component supports containment containment liner core shroud electrical and mechanical penetrations electrical cabinets electrical cables and connections equipment hatches heat exchangers piping pressure retaining boundaries pressurizer pump casings reactor coolant system pressure boundary reactor vessel seismic Category I structures steam generators valve bodies ventilation ducts	air compressors batteries battery chargers breakers circuit boards cooling fans diesel generators motors power inverters power supplies pressure indicators pressure transmitters pumps (except casing) relays snubbers switches switchgears the control rod drive transistors valves (except body) ventilation dampers water level indicators

To assist the licensees in perform their plant-specific aging assessments and avoid duplication of work from one plant to another the USNRC developed a comprehensive guidance document entitled, *Generic Aging Lesson Learned Report* (GALL) NUREG-1801. The document provides aging management matrixes for the various passive mechanical, electrical and structural components found in a nuclear plant. The GALL report also provides links and references to acceptable aging management programs inclusive of specific program attributes. An example of a typical aging matrix from the GALL report is shown in Table 4.

Table 4: *Typical Aging Matrix from GALL Report* (Source NUREG-1801)

NUREG-1801, Rev. 1 — VII C1-4 — September 2005

VII AUXILIARY SYSTEMS
C1 Open-Cycle Cooling Water System (Service Water System)

Item	Link	Structure and/or Component	Material	Environment	Aging Effect/ Mechanism	Aging Management Program (AMP)	Further Evaluation
VII.C1-14 (AP-59)	VII.C1.	Piping, piping components, and piping elements	Stainless steel	Lubricating oil	Loss of material/ pitting, crevice, and microbiologically influenced corrosion	Chapter XI.M39, "Lubricating Oil Analysis" The AMP is to be augmented by verifying the effectiveness of the lubricating oil analysis program. See Chapter XI.M32, "One-Time Inspection," for an acceptable verification program.	Yes, detection of aging effects is to be evaluated
VII.C1-15 (A-54)	VII.C1.2-a VII.C1.6-a VII.C1.1-a VII.C1.4-a	Piping, piping components, and piping elements	Stainless steel	Raw water	Loss of material/ pitting and crevice corrosion, and fouling	Chapter XI.M20, "Open-Cycle Cooling Water System"	No
VII.C1-16 (AP-56)	VII.C1.	Piping, piping components, and piping elements	Stainless steel	Soil	Loss of material/ pitting and crevice corrosion	A plant-specific aging management program is to be evaluated.	Yes, plant-specific
VII.C1-17 (AP-30)	VII.C1.	Piping, piping components, and piping elements	Steel	Lubricating oil	Loss of material/ general, pitting, and crevice corrosion	Chapter XI.M39, "Lubricating Oil Analysis" The AMP is to be augmented by verifying the effectiveness of the lubricating oil analysis program. See Chapter XI.M32, "One-Time Inspection," for an acceptable verification program.	Yes, detection of aging effects is to be evaluated

The licensee has a choice to utilize the generic findings of the GALL report as a technical basis for his plant, subject to verification of applicability. If the plant-specific conditions, materials, components or aging management programs are different, a plant-specific assessment is required. The GALL report relies heavily on a condition directed maintenance program (inspection, analysis and testing) for effective aging management that is to monitor the material conditions.

The aging management programs to be credited for license renewal, must meet a rigorous 10-point acceptance criteria shown in Table 5.

The GALL Report includes a comprehensive listing of all the plausible aging effects and mechanisms, with a definition and explanation of applicability. The basis for these aging effects and mechanisms are contained in the numerous references form the wealth of the aging research conducted by the industry, EPRI, DOE, and the USNRC. With the exception of a few industry-specific or unique degradation mechanisms, these aging effects and mechanisms are applicable to almost any industrial facility and are not specific to power plants. An edited version was extracted from the GALL report is provided in Appendix B.

The last important tool provided with the GALL report, is a series of aging management programs (AMPs), targeting the specific aging mechanisms and affected materials. Licensees are expected to implement these aging management programs as part of their maintenance program without much deviation. If plant-specific changes are required, they must be identified to the USNRC for approval. Each of the aging management programs has been developed with substantial industry input to reflect current aging

Table 5: *Aging Management Activity Program Elements* (Source, NUREG-1801)

Element	Description
1. Scope of the activity	Scope of the program/activity should include the specific structures and components subject to an aging management review for license renewal.
2. Preventive actions	Preventive actions should mitigate or prevent aging degradation.
3. Parameters monitored or inspected	Parameters monitored or inspected should be linked to the degradation of the particular structure or component intended function(s).
4. Detection of aging effects	Detection of aging effects should occur before there is a loss of structure or component intended function(s). This includes aspects such as method or technique (i.e. visual, volumetric, surface inspection), frequency, sample size, data collection and timing of new/one-time inspections to ensure timely detection of aging effects.
5. Monitoring and trending	Monitoring and trending should provide predictability of the extent of degradation and provide timely corrective or mitigating actions.
6. Acceptance criteria	Acceptance criteria, against which the need for corrective action will be evaluated, should ensure that the structure or component intended function(s) are maintained under all current licensing basis design conditions during the period of extended operation.
7. Corrective actions	Corrective actions, including root cause determination and prevention recurrence, should be timely.
8. Confirmation processes	Confirmation processes should ensure that preventive actions are adequate and that appropriate corrective actions have been completed and are effective.
9. Administrative controls	Administrative controls should provide a formal review and approval process.
10. Operating experience	Operating experience of the aging management activity, including past corrective actions resulting in program enhancements or additional programs or activities, should provide objective evidence to ensure that the effects of aging will be adequately managed so that the intended functions of the structure or component will be maintained during the period of extended operation.

management practices and to maintain effectiveness. There are 39 AMPs for mechanical component aging management, eight structural programs and six electrical programs. An example of an aging management program for concrete structures is provided in Appendix D.

As with the aging mechanisms and aging effects, the AMPs are equally applicable to other industrial facilities, with perhaps a minimized formality and quality control.

Much of the contents contained in the GALL report are repeated in a companion document called the License Renewal Standard Review Plan (SRP-LR), NUREG-1800. This document is for the use by the USNRC staff to assist in the review of the License Renewal applications and to assure consistency among the reviewers. The SRP-LR also provides guidance regarding components, aging mechanisms and aging effects not addressed in the GALL but which require plant-specific aging evaluations.

While the aging management programs are not mandatory, they represent one acceptable method to perform effective aging management under the license renewal rule. Licensees may deviate and apply their own versions. However, such programs are subject to acceptance by the USNRC and usually require a substantial justification to deviate from the standards. In this way, the AMPs constitute a near-mandatory status and the specific activities referred to the programs, become licensing commitments for the extended operating period. For components that are not covered by the GALL report or for which no standard AMPs are applicable, the applicant must perform a detailed documented aging management review.

For the typical plant, the aging management review resulted in the identification of about 200 to 400 specific aging management activities. The activities range from completely new programs to changes to existing programs (scope for additional components, more frequent inspections, different technology, new locations, etc) and administrative tasks to document activities, quality control and training. Most of the impact comes from the additional inspections and testing requirements to monitor the degradation and engineering analyses to demonstrate that existing design margins have not eroded and are adequate for the extended operating period. Examples of updated and new aging management activities and programs are shown in Table 6.

TABLE 6: *Typical New and Updated Aging Management Activities and Programs*

Updated Programs (examples):	New Programs (examples):
Boric Acid Corrosion Prevention Program	Alloy 600 Aging Management Program
Fire Protection Program	Buried Piping Inspection Program
Instrument Air Quality Program	Cast Austenitic Stainless Steel (CASS) Evaluation Program
Maintenance Program	Heat Exchanger Monitoring Program
Service Water System Reliability Program	Cable Management Programs
Structures Monitoring	Reactor Vessel Internals Programs
System Testing Program	Small Bore Piping Program
System Walkdowns Program	Wall Thinning Monitoring Program
	Water Chemistry Control - Chemistry One-Time Inspection Program

Time Limited Aging Analysis

One of the major provisions of the Rule is the identification and analysis of Time Limited Aging Analyses (TLAA). The licensee must identify and update time-limited aging analyses. During the design phase for a plant, certain assumptions about the length of time the plant will be operated are incorporated into design calculations for various SSCs. In order to obtain approval for a renewed license, these calculations must be shown to be valid for the period of extended operation, or the affected SSCs must be included in an appropriate aging management program.

In essence, the USNRC requires the licensee to go back to the original plant design documents and determine if the design criteria included specific time limited assumptions or criteria. Once identified, the original calculations or qualification tests must be updated for the new extended operating life. This process may be a simple ratio method to establish a new value for fatigue cycles, or it may involve a complex fatigue analysis, considering the used-up cycles and extended operating life.

A comprehensive review was performed by the industry to identify potential time limited aging analyses (TLAAs) that may be part of the original design basis, the underlying design codes and standards, and the qualifications tests (i.e. environmental exposure of cables, corrosion tests) that were performed in support of the original design life calculations. The principal issues identified by this industry review are (NUREG-1800 & NEI-95-10):

- reactor vessel neutron embrittlement
- prestressed concrete containment tendon prestress
- metal fatigue
- environmental qualification of electrical equipment
- metal corrosion allowance
- inservice flaw growth analyses
- inservice local metal containment corrosion
- high-energy line break postulated on fatigue cumulative usage factor

Once the licensee has identified their specific TLAAs, analysis must be performed to extend the design basis for the extended operating period or compensatory measures must be implemented. The licensee must demonstrate one of the following:

- The analyses remain valid for the period of extended operation or;
- The analyses have been projected to the end of the extended period of operation; or
- The effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

These options clearly include full or partial replacement of the component, requalification by testing, more sophisticated analyses (i.e. finite element analysis and fracture mechanics) or use of mitigative measures to impede or avoid degradation. Some plants have chosen to implement stricter preventive and predictive maintenance, one-time inspections to assess used-up margins, monitoring of the environments to recalculate cable life, new inspections to quantify degradation and installation of coupons to monitor corrosion and cracking.

The Maintenance Rule

Because active components in mechanical and electrical systems are normally operating, their performance can be monitored and trended to detect incipient degradation. Representative parameters that can be measured must be established for both the local components and for the complete system. Examples of local component parameters include flow, differential pressure, vibration, and delta temperature. Reliability and availability are examples of typical system performance parameters.

Within the nuclear power generation industry in the United States, the US Nuclear Regulatory Commission (USNRC) has promulgated a "Maintenance Rule" for the purpose of improving the performance monitoring of critical systems at all nuclear power plants in the United States.

Regulatory Requirements

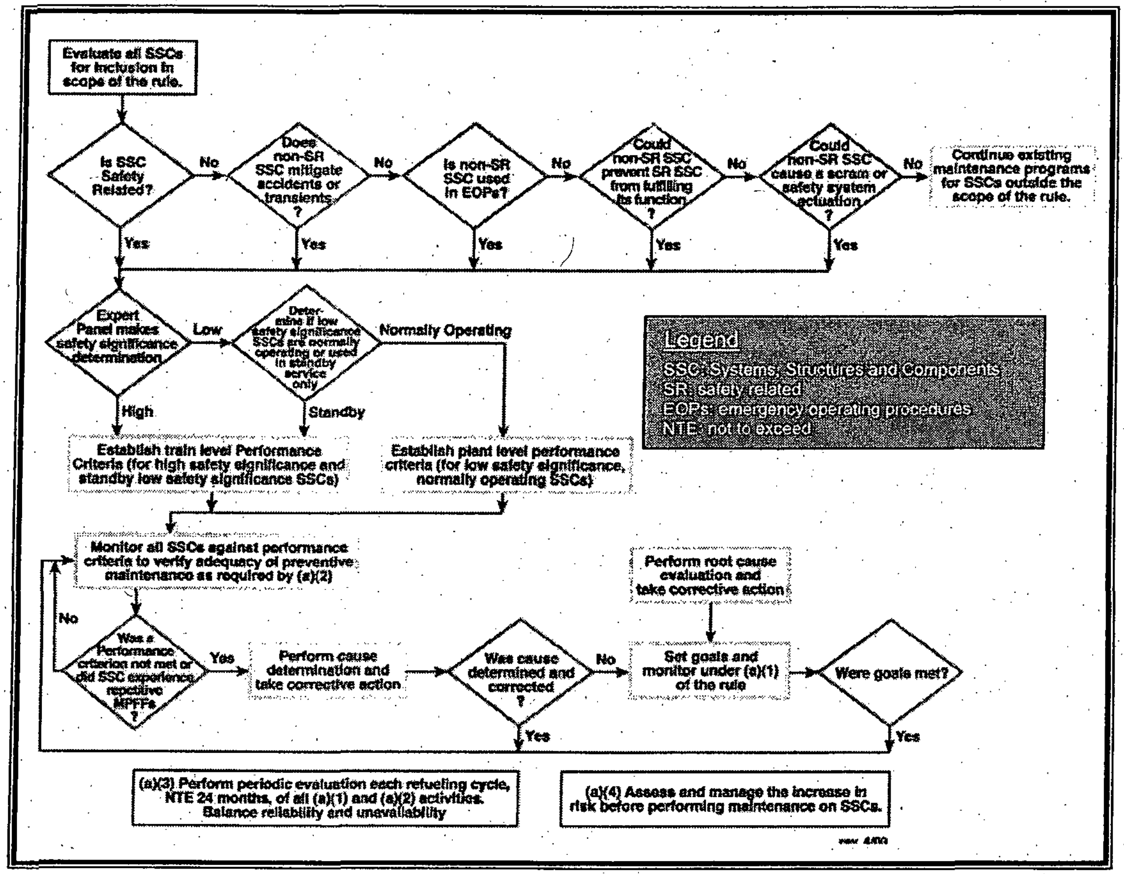
During the 1980s, the USNRC became concerned with the maintenance of nuclear power plants and the attendant decline in reliability. No regulatory provisions were in force to require uniform application of maintenance, except for the Technical Specifications, which required periodic surveillance testing, and the ASME Code, which required periodic inspections of the safety-related pressure boundary components. With the assistance of a number of volunteer plant owners, the USNRC conducted a survey of utility practices in an effort to establish the effectiveness of various maintenance programs (i.e. experience based, vendor recommended, preventive, corrective, run-to-failure), allocation of utility resources among safety and non-safety (power production) equipment and utility methods of monitoring and benchmarking performance. The survey results led the USNRC to conclude that more consistent and rigorous monitoring and reporting of individual system performance parameters was needed. Using industry input, to the USNRC developed a performance-based regulation that would allow individual plants to define the scope of the program, the performance parameters and the acceptance criteria. The plant specific application and implementation would be subject to inspection by the USNRC. The original Rule was issued in July 1991 and became effective in July of 1996 and the USNRC began their implementation inspections. The Rule was revised a number of times to incorporate lessons learned, clarifications and new requirements.

The Maintenance Rule Provisions

The Maintenance Rule was issued under the United States Code of Federal Regulations. This is a mandatory rule that all commercial nuclear power plants must follow. A copy of the full text of the Maintenance Rule is provided in Appendix A. Although the Rule consists of only a single page, the underlying documentation, interpretations, and guidance reports amounts to thousand of additional pages of material and information.

The Maintenance Rule analysis process is shown in Figure 7.

Figure 7: *Simplified Flow Chart of the Maintenance Rule* (Source: USNRC)



The key provisions of the Rule are:

- defining systems monitoring requirements
- preventive maintenance versus availability/reliability
- corrective action goal setting
- operating experience considerations
- demonstrations of preventive maintenance (PM) effectiveness
- bi-annual performance reviews
- quantification of on-line risk

Systems Monitoring Requirements

The Rule makes a significant distinction between important systems that need to be performance monitored at the train level and those systems that can be monitored at the plant level. The systems that are considered to be safety significant with equally or diversely redundant safety systems typically have two or three trains or channels.

Standby systems (systems that are activated in response to an accident or fire or are required to mitigate accident consequences) are monitored using reliability as a performance parameter. Reliability can be measured by such indicators as fail-to-start or fail-to-run per 100 attempts.

Normally operating systems are monitored using availability as a performance measure. Availability is determined as the fraction of system available hours during the mission time divided by the mission time. When assessing reliability and availability, the success or ability of accomplishing the defined safety functions is considered. This permits some level of degradation, as long as the system's functions are not compromised.

Preventive Maintenance versus Availability/Reliability

The Rule recognizes the conflict between performing preventive (invasive) maintenance that requires the system or component to be removed from service and the need to maintain satisfactory availability and/or reliability. One of the requirements mandates that an adequate balance of the two be maintained and reported.

Corrective Action Goal Setting

If a system cannot meet its performance criteria over a period not exceeding 24 months, corrective action is required and a new and more specific performance criteria must be established (Goal Setting) to demonstrate that the corrective action has been effective. This Goal Setting assures that recurring problems are fixed.

Operating Experience Considerations

Operating experience must be considered when establishing the performance parameters and criteria. This experience may be based on generic industry experience or the historical plant performance, failure rates, or reliability / availability values assumed in the plant's probabilistic risk analysis (PRA).

Demonstrations of PM Effectiveness

Systems that are monitored at the plant level require demonstration that the preventive maintenance programs are effective. Plant level performance criteria can include repetitive failures, plant shutdowns, initiation of safety systems and lost production. If the established criteria levels are exceeded, the system must be elevated to "system level monitoring".

System level monitoring requires that an elevated level of monitoring must continue until it can be demonstrated that the system has achieved its new system level performance, before the system is returned to plant level.

Bi-Annual Performance Reviews

The result of the system monitoring and trending activities is subject to bi-annual review to highlight the:

- performance problems
- corrective actions taken
- changes in performance parameters or criteria

- assessment of the balance between maintenance outages and system availability
- evaluation of industry operating experience

The evaluation of industry operating experience is an attempt to identify precursors or incipient failures that may have occurred at other plants and may have generic implications.

<u>Quantification of On-Line Risk</u>

A new paragraph was added to the Rule in 2000 to address the risk associated with plant configuration changes made during operation. This includes systems that are taken out-of-service for maintenance or due to failure/degradation. The on-line risk is influenced by the importance of the unavailable system, the period of time that it is not available, as well as the status of other safety related systems. As a consequence, the USNRC now requires that the on-line risk must be quantified to support continued operation of the plant.

Modifications/Improvements to the Rule

Following the original issue of the rule in 1991, the Nuclear Energy Institute (NEI) formed a utility task group to develop an industry guide, NEI-93-01, to assist the plants with the implementation. The USNRC conducted a number of early plant implementation audits in 1996 and based on these audits it was determined that some interpretations and improvements were desirable. The nuclear industry, represented by the Nuclear Energy Institute (NEI), discussed the implementation issues with the USNRC and subsequently generated a Revision 1 to NEI-93-01 in 1996.

The USNRC reviewed the revised NEI-93-01 for generic acceptability. In 1997 the guide was endorsed with some additional provisions (USNRC Regulatory Guide 1.160 Revision 2). The most significant addition was the inclusion of structures including concrete and steel structures that house or protect equipment covered within the scope of the Rule.

In 2000 the Rule was modified again to address on-line risks associated with maintenance activities. The USNRC added a new paragraph A-4 that then required the NEI to revise NEI-93-01. The new Section 11 provides guidance to the industry on how best to assess on-line risk associated with their maintenance activities. The USNRC endorsed the changes to NEI-93-01 in the USNRC Regulatory Guide 1.180.

Regulatory Inspections and Guidance

The USNRC started plant-specific inspections and audits in 1996 and 1997 to verify the acceptability of methods and procedures and the programmatic approaches taken. Because the rule is performance based, these inspections were unique and required substantial guidance and training of the inspector teams. The training guides and inspection procedures were made available to the industry. This allowed self-assessments and readiness reviews to be conducted prior to USNRC on-site inspections. Lessons learned from the inspections were communicated to the industry in a number of workshops and seminars.

Monitoring Issues

Monitoring important systems at the train level is considered an effective way to identify poorly performing equipment. A redundant high performance train could otherwise shadow the poorly performing train. Performance monitoring at the train or channel level is therefore mandated for risk significant systems. The USNRC was also concerned that generic problems in cross-system component groups (valves, motors, pumps, solenoids) would not be readily identified. As a result all plants are now tracking functional failures, which are periodically reviewed to identify trends of multiple component failures. A definition for a "Repetitive Functional Failure" was crafted to include: "Failures of another same component with identical cause".

Determining meaningful performance parameters for structures became a difficult task. A "Structures Monitoring Program" was created and implemented to periodically inspect (i.e. five to ten year intervals) for functional degradation. The acceptance criteria were defined in the American Concrete Institute (ACI) standards or the American Institute of Steel Construction (AISC) standards. If performance problems are identified, corrective action is required and the structure must be re-inspected at shorter intervals until it can be demonstrated that the fix was effective.

Industry Aging Management Programs (PM Basis and LCM)

The EPRI PM Basis Program

Recognizing the license renewal and maintenance rules as effective aging management tools for the safety-related systems and components in the plants, the industry needed to develop commensurate programs to be applied for the traditional part of the plants, the power production equipment. It is obvious that these systems must also undergo a transformation to support an extended operation. The first of these comprehensive efforts was the development of the Preventive Maintenance Basis Program (PM Basis) by EPRI to cover the majority of generic components and commodities found in the plants. The objective was to research and document the "Industry Best Practices" with respect to effective maintenance and aging management practices. Previously, plant maintenance was largely based on the equipment vendor recommendations, often without a solid technical basis for the requirements, except to protect the equipment warranty provisions.

Table 7: *EPRI PM Basis Component Listing*
(Source EPRI TR106857)

Component Description	Volume
Air Operated Valves	V1
Medium Voltage Switchgear	V2
Low Voltage Switchgear	V3
Motor Control Centers	V4
Check Valves	V5
Motor Operated Valves	V6
Solenoid Operated Valves	V7
Low Voltage Electric Motors (600V and below)	V8
Medium Voltage Electric Motors (between 1kV and 5kV)	V9
High Voltage Electric Motors (5kV and greater)	V10
Direct Current Electric Motors	V11
Vertical Pumps	V12
Horizontal Pumps	V13
Reciprocating Air Compressors	V14
Rotary Screw Air Compressors	V15
Power Operated Relief Valves - Solenoid Actuated	V16
Power Operated Relief Valves - Pneumatic Actuated	V17
Pressure Relief Valves - Spring Actuated	V18
HVAC - Chillers and Compressors	V19
HVAC - Dampers and Ducting	V20
HVAC - Air Handling Equipment	V21
Inverters	V22
Battery Chargers	V23
Battery - Flooded Lead-Acid	V24
Battery - Valve-Regulated	V25
Battery - Nickel-Cadmium (NICAD)	V26
Liquid-Ring Rotary Compressor and Pump	V27
Positive Displacement Pumps	V28
Relays- Protective	V29
Relays- Control	V30
Relays- Timing	V31
Heat Exchangers	V32
Feedwater Heaters	V33
Condensers	V34
Main Feedwater Pump Turbines	V35
Terry Turbines	V36
Main Turbine EHC Hydraulics	V37
Transformers- Station Type Oil Immersed	V38
I&C Components	V39

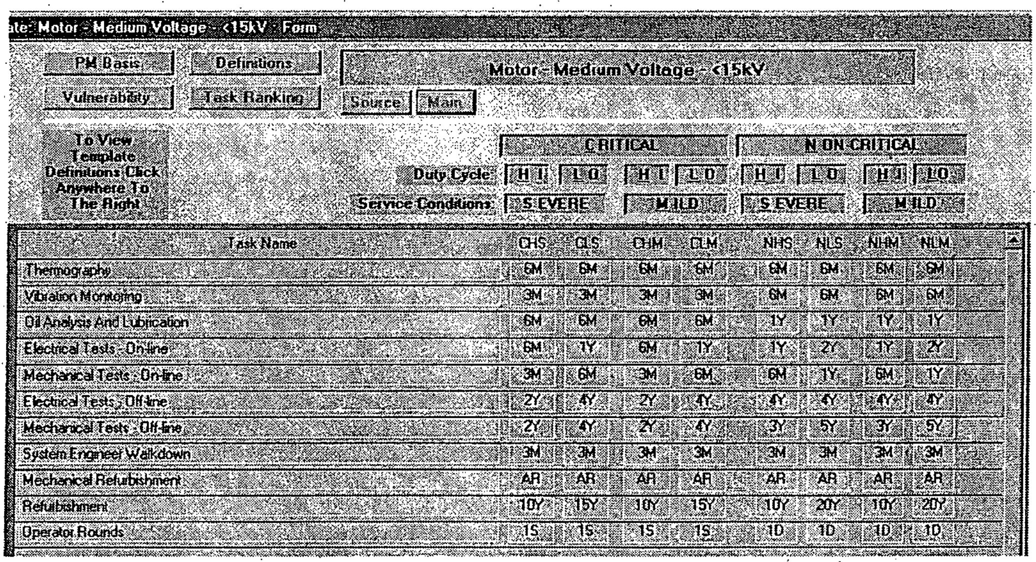
The PM Basis program initially included 39 component templates, each documented in a separate report volume (see Table 7). The program scope was later expanded to add a variety of instrumentation groups. For each component, the program determined the appropriate maintenance activities, the recommended frequency for the activity and the effectiveness of the action. The program also provided a first attempt at correlating PM frequency with reliability, i.e. the more often a component is tested or inspected, the more reliable it is supposed to be and the corollary, what is the reliability reduction if the PM task is eliminated. In many cases, a single task will not provide a major improvement in reliability, but a combination of PM tasks can make a major difference.

In addition to the individual component reports, EPRI converted the templates to electronic format, so that they can be accessed via computer and component reliability manipulations can be exercised on the ACCESS based software. The best practices are captured on a summary template for each component. The templates recognize the fact that not all components are of equal importance and therefore the level of preventive maintenance may be significantly different, dependant on the components service duty, environmental exposure and functional importance. The different levels of recommended PM for the various categories (there are eight different categories to choose from) are shown on the templates. An example template for large electric motors is shown in Figure 8.

The Life Cycle Management Planning (LCM) Process

The Life Cycle Management planning methodology was developed under EPRI and utility sponsorship to create a tool for the long-term maintenance planning, using both, technical and economic measures to find the maintenance plan that will give the highest reliability at the lowest cost. The LCM process is fairly complex in that it requires a relatively accurate representation of the plant's historic performance, component failures, failure consequences, such as lost power generation, regulatory scrutiny, corrective maintenance costs, and the impact of a poor plant performance on the corporate image and financial picture. However, given the eventual possibility that the

Figure 8: *EPRI PM Basis Template Example*



Task Name	CHS	CLS	CHM	CLM	NHS	NLS	NHM	NLM
Thermography	6M	6M	6M	6M	6M	6M	6M	6M
Vibration Monitoring	3M	3M	3M	3M	6M	6M	6M	6M
Oil Analysis And Lubrication	6M	6M	6M	6M	1Y	1Y	1Y	1Y
Electrical Tests - On-line	6M	1Y	6M	1Y	1Y	2Y	1Y	2Y
Mechanical Tests - On-line	3M	6M	3M	6M	6M	1Y	6M	1Y
Electrical Tests - Off-line	2Y	4Y	2Y	4Y	4Y	4Y	4Y	4Y
Mechanical Tests - Off-line	2Y	4Y	2Y	4Y	3Y	5Y	3Y	5Y
System Engineer Walkdown	3M	3M	3M	3M	3M	3M	3M	3M
Mechanical Refurbishment	AR	AR	AR	AR	AR	AR	AR	AR
Refurbishment	10Y	15Y	10Y	15Y	10Y	20Y	10Y	20Y
Operator Rounds	1S	1S	1S	1S	1D	1D	1D	1D

plants will operate for 60 years or longer, it was necessary to change the maintenance planning horizon and to be able to forecast major capital projects with respect to timing and cost for the foreseeable future. The following is a quote taken from the EPRI summary report for LCM planning:

"Life Cycle Management planning is intended to provide an effective long-term planning tool for minimizing unplanned capability loss and optimizing maintenance programs and capital investments consistent with plant safety and an identified plant operating strategy. Such an operating strategy might include license renewal and/or plant power uprating. An LCM Plan addresses such issues as aging management, preventive maintenance, obsolescence, and the replacement or redesign of a structure, system or component (SSC) important to safety and plant operation. In short, LCM Planning is viewed as a viable process to systematically identify and examine the important SSCs, optimize their contribution to plant performance, reliability, safety and value, and prepare long-term maintenance management plans and resource projections."

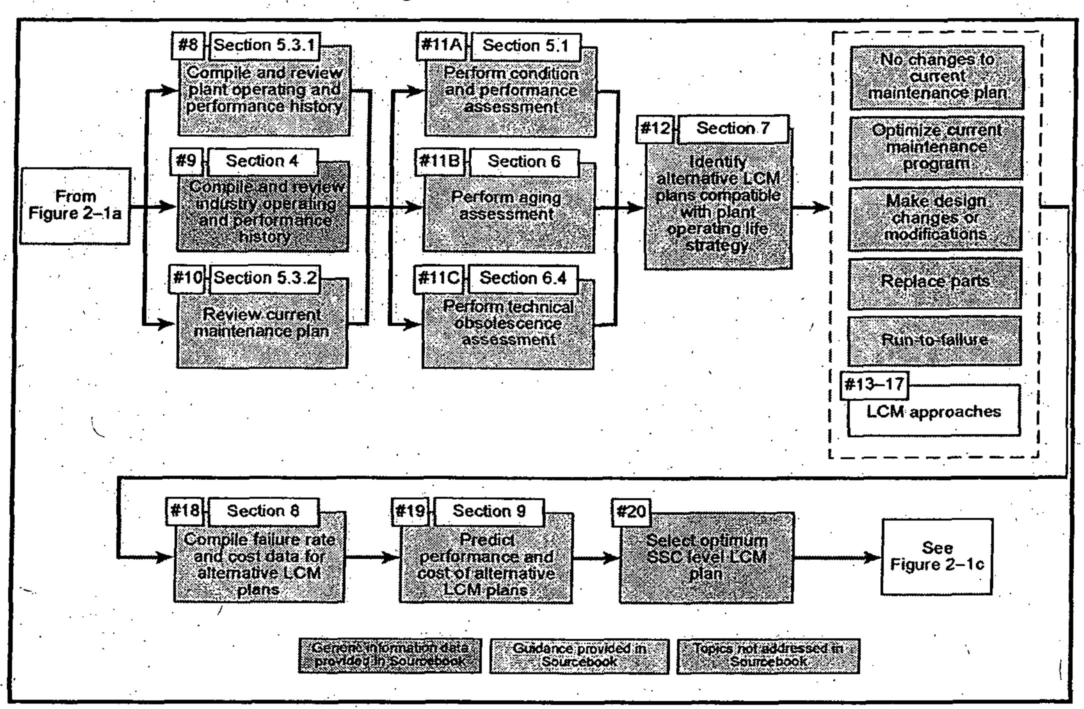
The basic steps of the LCM process are delineated on the simplified diagram, shown in Figure 9. The major steps are briefly reviewed to help understand the interrelationship and task objectives.

Compiling Performance and Operating History

Some plants have included cost data in their WO database, which when trended over time, provides an additional parameter to measure maintenance effectiveness. More money does not always lead to better reliability. To benchmark the plant's performance, similar operating data, including generic failure rates, is assembled from the EPIX

Figure 9

LCM Planning Flowchart – Technical and Economic Evaluation



database and other sources (such as the French EDF Eireda database). Benchmarking has the principal objective to place the specific plant performance relative to its peers. If the plant experiences a failure rate of twice the industry average, there is ample room for improvement and investments are economically justified. If the plant turns out to be already a leader in performance, additional improvements are difficult to sell.

Another aspect of this performance compilation task is the review of the plant's maintenance programs and procedures and to compare the list with the industry "Best Practices", such as the EPRI PM Basis Templates, to identify specific shortcomings and gaps that can be closed to enhance the plant performance.

Condition Assessment

In order to establish a baseline for the plant's equipment performance and reliability, the operating history over the last 5 to 10 years is reviewed and trended. Typically, the plant will have a work order database from which the preventive and corrective work orders can be accessed. A simple count per year will provide a meaningful trend to see if the maintenance activities are increasing, decreasing or portray a stable trend. Also, the ration of preventive to corrective work orders will provide some indication for a successful maintenance program (corrective work orders are decreasing), or the trend will point to problems, that is failures are increasing as an indication of progressive aging problems.

The age of the plant can have a profound effect on the performance and condition of its components; therefore it is necessary to have a good understanding of the material condition of the components at the time the assessment is made. Material conditions are determined from the review of maintenance history, such as inspection reports, test data, diagnostic data, craft feedback, spare parts use, operating records and a plant walkdown. From this an estimate can be rendered if the plant age is commensurate with its condition, that is, if its useful life has been expended faster than expected or the current condition is better than anticipated.

Aging Evaluation

Next is the aging evaluation to be performed for each major component or commodity group. Here the work performed by the industry groups and USNRC in support of the license renewal represents a basis to start the assessments. Typically a matrix is constructed, showing the basic component parts and materials, their applicable aging effects and associated aging mechanisms and the effective aging management programs. A typical aging matrix (this one for electric motors) is shown in Table 8.

For each line item, the plant's matching aging management program is identified and reviewed to determine if the effective attributes are included and to highlight any gaps that need to be addressed. The previous review of the operating history and plant condition records also contributes to this task to ascertain applicability and to assure that plant specific conditions are not overlooked.

Table 8: *Typical Aging Management Evaluation Matrix (Electric Motor)*

Structure or Components	Component/ Material Grouping	Plausible Aging Effects	Potential Aging Mechanisms	Present Plant Aging Management Programs
Rotor and Stator Windings End turns	Copper and Insulation	Discoloration, Burning, melting	Winding Shorts, Moisture Intrusion, Aging, Dirt, High Temperature	Motor Status Monitor. Refurbishment Consider internal inspection
		Overheating	Aging, Dirt	See above
Rotor Bars	Steel	Loose	Vibration, Age, Fatigue	Vibration monitoring On-line electrical tests
Rotor Shaft	Steel	Deformation, cracking	Vibration, fatigue, corrosion	Vibration monitoring Bearing temp. monitoring Internal visual inspection
Bearings	Various	Loss of Material, Cracking	Friction, Wear, Loss of lubrication	Vibration monitoring Temperature monitoring Oil sampling, analysis Thermography Internal inspection
Wiring, Terminations	Copper, Insulation	Loss of Contact, Cracking	Pinched, crimped, loose wire, Aging, corrosion	Thermography Visual inspection High pot tests
Frame, Base Plate	Carbon Steel	Loss of Material, Cracking, Deformation	Corrosion, Vibration, Loose Bolts	Vibration monitoring Visual inspections Recoating MR Structures Monitoring
Cooling Coils, Oil and water piping/reservoirs	Carbon Steel, SS	Leakage, Cracking	Corrosion, Wear, Vibration, Fatigue	Oil sampling, testing Visual inspection (E/I) Operator/SE rounds
Oil sight glass, Oil seals	Various non-metallic	Leakage	Corrosion, aging, wear, fatigue	Visual inspection Operator/SE rounds Periodic replacement
Sensors (RTDs, TCs, LVDTs, level, pressure, DP)	Various	Loss of signal, Drifting	Vibration, aging, corrosion	Calibration Replacement
Space heaters	Copper, insulation	Loss of continuity	Loose, broken wire, Moisture accumulation	Winding temp. monitoring Functional testing Thermostat calibration

Obsolescence Assessment

An obsolescence assessment provides a critical review of the potential technical obsolescence of the equipment. The industry is experiencing a serious exodus of original equipment vendors, many vendors do no longer support warranty and equipment services or have terminated production of spare parts. This puts the plant into a vulnerable position, leaving few of acceptable options, including re-engineering or reverse engineering, substituting newer models that often do not fit the original configuration envelope, upgrading technology (analog to digital) creating electronic-computer interface problems or scavenging parts from abandoned plants. The obsolescence assessment criteria and the relative ranking applied by a number of plants are shown on Table 9.

The first step is to assess the exposure level to obsolescence. Typically the electrical-electronic and instrumentation and control components are affected most prominently.

Obsolescence is ranked by applying a set of questions and ranking the applicability of each question. The total numerical value is compared to a traffic light scale to indicate the eminence of obsolescence. While this may not be a true scientific process, it nevertheless provides a timeframe for corrective or mitigative action.

The "traffic light" ranking for obsolescence is:

- Total Score is < 6.0, RED and the SSC obsolescence is serious. Potential options to deal with obsolescence and contingency planning should be identified. Guidance on the modeling, timing and costs of these contingencies and the associated risks should be provided.
- Total Score is between 6.0 and 10.0, YELLOW and the SSC may have longer-term concerns for obsolescence. Contingency planning and options should be considered.
- Total Score is > 10, GREEN and the SSC is not likely affected by obsolescence.

TABLE 9: *Technical Obsolescence Evaluation Criteria (Breakers)*

	Technical Obsolescence Evaluation Criteria	Base Score Yes=5 No=0	GE AKR	GE AM	W DHP	ABB K-line
1	Is the SSC still being manufactured and will it be available for at least the next five years?	5	0	0	0	5
2	Is there more than one supplier for the SSC for the foreseeable future?	3	0	0	0	0
3	Can the plant or outside suppliers manufacture the SSC in a reasonable time (within a refueling outage)?	3	0	0	0	3
4	Are there other sources or contingencies (from other plants, shared inventory, stock-piled parts, refurbishments, secondary suppliers, imitation parts, commercial dedications, etc) available in case of emergency?	3	3	3	3	3
5	Is the SSC frequency of failure/year times the number of the SSCs in the plant times the remaining operating life (in years) equal or lower than the number of stocked SSCs in the warehouse?	3	0	0	0	0
6	Can the spare part inventory be maintained for at least the next five years?	3	3	3	1	3
7	Is the SSC immune to significant aging degradation?	1	0	0	0	0
8	Can newer designs, technology, concepts be readily integrated with the existing configuration (hardware-software, digital-analog, solid-state, miniaturized electronics, smart components, etc)?	3	1.5	0	3	3
	Total Obsolescence Score	24	7.5	6	7	17

Determining LCM Planning Options and Plant Strategies

At this point in the LCM planning process, all the potential enhancements should be identified, such that a concise list of new or modified maintenance activities can be compiled, along with their costs and timing of implementation. Each goal can be met by a number of different options, called Alternatives in the LCM process. The Alternatives include:

- Maintain the Current Maintenance Program

  This is considered the base case against which other options are compared. The model assumes that current maintenance practices are continued and failure rates will gradually increase commensurate with progressive aging. Equipment replacement at time of failure is the planned corrective action.

- Optimize the PM Program

  Low cost PM activities are implemented on the basis of their cost effectiveness. Existing tasks are fine tuned or modified to be more effective and tasks with little payback are eliminated. A variant to the PM program is preventive replacement of components that have reached their predetermined useful life.

- Make Design Changes and Modifications

  Typically this option is a more costly alternative and makes sense for long-term operation if the design change avoids costly failures and lost power generation. There is a caution though in that design changes are often not proven concepts and may turn out worse for the plant.

- Designate Components as Run-to-failure

  For many unimportant components this is a reasonable alternative. In order to be effective, there must be a task that determines when failure has occurred so that a replacement can be installed.

Plant operating strategies need to be established, such that the LCM planning can consider the appropriate planning horizon, which is the remaining operating life, whether the plant is base loaded or cycled and if a power uprate is contemplated.

Economic Analysis of LCM Alternatives

The last step of the LCM process is to consolidate the technical data, failure data and financial/cost data to be loaded into financial analysis software, called LcmVALUE, to perform the Net Present Value (NPV) and Benefit to Investment Ratio (BIR) calculations that provide the measure of economic feasibility. The Alternative with the lowest NPV cost and the highest BIR is the preferred option. If the results are very close (i.e. within 1% of each other) additional sensitivity and uncertainty analysis are typically performed to render a confident recommendation. Results are highly dependant on long-term financial assumptions (such as discount rate, inflation rate, cost of power generation, cost of labor/materials, etc) and small changes cause large fluctuations in the results.

The Use of Probabilistic Risk Analysis for Maintenance

The probabilistic risk analysis (PRA) was initially developed for the safety related part of the nuclear power plant to facilitate simulation of various accident scenarios. Over time, plant-specific failure data became available and Bayesian updating brought about much more accurate modeling of the plant. With the promulgation of the Maintenance Rule, the PRA was expanded to now also include the power generation part of the plant, such that on-line risk modeling has become feasible and is performed on a routine basis. Outage times associated with preventive maintenance and surveillance testing as well as unanticipated equipment failures (emergent events) can be modeled and the risk impact associated with maintenance activities can be assessed on a continual basis. As plants continue to age, the increased equipment failures, if any, will be captured and the overall plant risk changes will have to be managed within the acceptance limits. This is another form of aging management trending at a higher level.

This PRA fidelity has led to new uses of the PRA, including risk ranking (RRW and RAW) of individual systems, evaluation of configuration and design changes prior to actual implementation and risk informed inspection plans (locations and frequency). Most recently, the USNRC has issued guidance for plant owners to apply PRA to fire protection and quality assurance programs.

Regulatory and Industry Aging Research

Early EPRI Pilot Plant and Demonstration Projects for License Renewal

As noted previously, the EPRI and DOE co-sponsored life extension pilot plant projects were initiated to study the feasibility and boundaries of nuclear plant life extension beyond the licensed 40-year life. With the new construction of power plants virtually coming to a halt after the 1979 Three Mile Island event, the electric generation industry and the US Department of Energy (DOE) were looking at long-term solutions to a looming energy crisis. Extending the plant life by some 20 years is equivalent of building 50 new power plants. The objectives of these early studies, as quoted in the Phase 1 BWR Pilot Plant Life Extension Report were:

> *To determine a realistic life goal for BWR plants, to identify major degradation mechanisms and potential technical obstacles to life extension, and to provide a methodology for BWR life extension programs.*

As the project was nearing completion and confidence in life extension was assured, economic obstacles and limits became an additional concern, as the list of potential new aging management activities and component replacements grew. The projects did develop the concept of "Critical Components" to delineate those that are essential to function and must be carefully managed to achieve the new life goals. It was also discovered that steel and concrete structures are not immune to aging and require aging management, largely through preventive techniques such as sealing, protective coatings and cathodic protection.

With the success of the pilot plants, a Phase 2 project was initiated to begin aging assessment of most of the plant components and commodity groups (cable, piping, structures, pressure boundary components, batteries, diesel generators, power generation equipment, etc). Among the top twelve critical components, all but two were passive components, the control center and diesel generators being the only active components. The Phase 2 report laid the foundation for identifying potential aging effects and mechanisms, their rate of degradation, manifestation of degradation and vulnerable locations. The studies also provided a first glance at potential aging management tactics from preventive/predictive maintenance, mitigation techniques, replacement options and repair feasibility.

The demonstration projects were initiated following the USNRC promulgation of the original License Renewal Rule in December 1991. The principal objective was to test the Rule's provisions and to generate the first license renewal application. It turned out not to be feasible and became unworkable in addition to plant owners concerns for an unstable licensing environment with open interpretation of the actual requirements. The license renewal application was never filed and the action prodded the NRC to revise and simplify the rule in 1995.

DOE-Sandia Aging Management Guides (AMG)

During the license renewal demonstration project phase, a need arose to study the critical components in more detail and to generate a generic AMG that could be used by other plants in their applications as well as be subjected to NRC review. The USDOE through the Sandia National Laboratory contracted for the development of ten individual AMGs, using a standard format and content guide. The ten critical components to be covered were chosen by an industry consortium and included the following reports:

- Electrical Switchgear (SAND93-7027)
- Pumps (SAND93-7045)
- Battery Chargers, Inverters & Uninterruptible Power Supplies (SAND93-7046)
- Power and Distribution Transformers (SAND93-7068)
- Motor Control Centers (SAND93-7069)
- Heat Exchangers (SAND93-7070)
- Stationary Batteries (SAND93-7071)
- Tanks and Pools (SAND96-0343)
- Electrical Cable and Terminations (SAND96-0344)
- Non-Reactor Pressure Boundary Piping (Draft) (TR-88953

While these reports cover both, passive (Heat Exchangers, Piping, Tanks/Pools, Cable) and active components (batteries, inverters/UPS, pumps, transformers, switchgear and motor control centers) they have become a valuable industry reference for the assessment of power production equipment. The AMGs contain a comprehensive review of industry operating experience, failure data, aging management techniques, and aging management options. The Cable AMG has become the industry bible on cable degradation, cable life determination and cable aging management.

EPRI Generic License Renewal Industry Reports for Major Components

In parallel to the DOE-Sandia AMGs EPRI also produced ten License Renewal Industry Reports. The EPRI addressed issues related to both the boiling water reactors (BWR) and the pressurized water reactors (PWR).

The EPRI reports were developed with participation from the General Electric BWR and Westinghouse PWR Owners Groups. The objectives of the EPRI reports were to provide the nuclear industry with aging technical basis documents and to support the technical review of license renewal applications by the USNRC.

The long-lived passive components and structures examined in the reports included:

- BWR plant primary containment
- PWR containment structures
- Class 1 structures
- PWR reactor coolant system
- low voltage, in-containment, environmentally-qualified cable

- BWR primary coolant pressure boundary
- BWR and PWR reactor vessels
- BWR and PWR reactor vessel internals

These reports are in-depth studies of historical performance and operating experience, failures and failure history, aging effects, and aging mechanism. The reports also provided information on aging management technologies and programs and discussed the aging management options for component parts and aging mechanisms that are not currently being managed or are not accessible (such as, underground structures, embedded steel and piping, and cable in conduits).

Over the years these reports have been of significant value for both the US nuclear industry and regulator as well as for nuclear plant operators and regulators in other countries. In particular, the reports on structures and containments have formed the basis of similar aging reports developed by the International Atomic Energy Agency in Vienna.

Much of the information in the reports on Class 1 structures and cables is application to both nuclear and non-nuclear facilities.

NRC Nuclear Plant Aging Research (NPAR) Program

To compensate for and to supplement the industry research of component aging, the USNRC funded a large multimillion-dollar research program to study aging of more than 100 different topics and components. Most of the actual research was conducted by the national laboratories (Oakridge, Argonne, Pacific Northwest, Sandia, and Idaho). The USNRC managed the program and provided for the technical review of selected reports by industry experts and users. A summary report (NUREG- 1377) was generated and updated annually to maintain an overview of the program status, components and topics being studied, short briefing reports and summaries for those reports completed. The reports for the selected components included passive and active components, as well as special topics, such as fatigue, material embrittlement, monitoring for aging, maintenance issues, seismic effects, and operating experience. Most of these reports are readily available from the NRC website. A more detailed discussion of the NPAR Program can be found in the companion briefing report *Condition Monitoring of Passive Systems, Structures, and Components* (CGI Report 06:22).

EPRI Generic Aging Management Tools

As a follow-up to the earlier industry reports for critical component aging, EPRI consolidated the research conducted within those reports, other owner's group initiatives, the NRC NPAR program and the early LICENSE RENEWAL applications in a series of Aging Management Tools. The three documents provide specific guidance in matrix format (similar to the later GALL report) to license renewal applicants for the applicable aging effects, mechanisms, exposure environments, affected materials and effective aging management programs. The tools are as follows:

- *Mechanical Implementation Guideline And Mechanical Tools* – contains a number of individual reports to cover the applicable service conditions and environments for:
  - treated water conditions
  - raw water
  - oil containing systems
  - gas containing systems
  - external surfaces
  - bolting
  - heat exchangers
  - fatigue affected systems
- *License Renewal Electrical Handbook* – contains aging management guidance for electrical cable and terminations, penetrations, buses, conductors and insulators.
- *Aging Effects for Structures and Structural Components (Structural Tools)* -- contains aging management guidance for steel and concrete structures (beams, columns, floors, walls, foundations, roofs, etc), above and below grade, underwater, in freeze-thaw climate, indoors and outdoors. Also covered are piping and cable tray supports, electrical and control cabinets, racks and enclosures, fire barriers, elastomer seals and barriers, galvanized steel and threaded fasteners. An example of the aging matrix for steel components is shown on Table 10.

The INPO AP-913 Equipment Reliability Program

The Nuclear Plant Reliability Data Search (NPRDS) database was created by INPO following the Three Mile Island event to respond to NRC requests for generic operating experience accumulation and assessment. Each plant provided input of component failures and causes to facilitate searches and to identify precursors to potential failures. With the promulgation of the maintenance rule, a new software tool was required to manage the failures associated with the equipment included under the Maintenance Rule. These failures are considered "Maintenance Preventable Functional Failures" (MPFFs) and repeat failures and are reportable under the Maintenance Rule. In operation since 1996, the database now contains more than 100,000 failure events and descriptions and as such is a credible basis for establishing component failure rates. One major shortcoming is the absence of component populations, such that component estimates need to be made for the 104 operating plants. For some commodities, such as valves, breakers or cables, uncertainties are encountered. Nevertheless, the database has become a very useful tool to examine operating experience and failure modes. Another caution for the use of the data is the fact that reporting of failures is only required for systems and components included in the scope of the Maintenance Rule, that is largely safety related equipment.

Table 10: *Applicable Aging Effects for Structural Steel Components and Materials*

APPLICABLE AGING EFFECTS	CARBON STEEL	LOW-ALLOY STEEL	GALVANIZED STEEL	STAINLESS STEEL
Loss of Material				
General Corrosion	Y	Y	N-protected atmosphere/weather Y-exposed atmosphere/weather	N
Galvanic Corrosion	N	N	N	N
Crevice Corrosion	N	N	N	N
Pitting Corrosion	N	N	N	N
Erosion and Erosion Corrosion	NA	NA	NA	NA
Microbiologically Induced Corrosion	N	N	N	N
Wear	N	N	N	N
Cracking				
Hydrogen Damage	N	N	N	N
Stress Corrosion	N	N	N	N
Fatigue	N	N	N	N
Mechanical Distortion				
Creep	N	N	N	N
Fatigue	N	N	N	N
Change in Material Properties				
Elevated temperatures	N	N	N	N
Irradiation Embrittlement	N*	N*	N*	N*
Intermetallic Embrittlement	NA	NA	N-provided temperature < 400 °F	NA

Key: Y- aging mechanism is applicable
N- aging mechanism is not applicable
NA- Not Applicable to this chapter
*- Outside Primary Shield Wall

While not a bona fide research program, this INPO developed reliability management guide provides plant owners with a structured methodology to more effectively apply and manage their maintenance programs. The guide is not mandatory and plant owners can customize their programs to incorporate existing programs and procedures, as long as the principal objective of improving equipment reliability is met. The programmatic details are discussed in an earlier section of this report.

NEI Guidelines

The Nuclear Energy Institute (NEI) has accepted the responsibility of developing industry guidelines for the implementation of new regulatory requirements and other topics not addressed by EPRI or INPO, such as business planning. The three most prominent guides associated with aging management of plant systems, structures, and components are:

- NEI-95-10, *Industry Guidelines for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule Plants* – this guide is discussed in the License Renewal Rule section of this report and in the companion briefing report CGI 06:22
- NEI-93-01, *Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants* – this guide is discussed in the Maintenance Rule section of this report
- NEI-AP-940, *Nuclear Asset Management Process Description and Guideline*:

In NEI-AP-940 asset management process guidance includes strategic and generation planning, project evaluation and ranking, long range planning, budgeting, and plant / fleet valuation. The process deals with the high-level business management of a fleet or a single plant. The most interesting section of this guide is the topic of project evaluation and ranking. Industry surveys showed that there is no consensus with respect to the method of selecting and ranking specific projects from a multiple projects listing and being restrained by a fixed budget. Many different methods have been proposed, from risk ranking, expert panel (Delphi), cost-benefit, operational priorities, safety considerations and the rucksack method (what to take with you in a fixed volume rucksack for a one week survival trip).

Ongoing EPRI Aging Research

A lesson learned about aging management, is that no matter how precise and detailed the aging studies are performed, there is always the unexpected, often a combination of events that surprises the engineers. In the nuclear industry there is no exception and unknown material behavior, degradation mechanisms and aging effects are discovered as the plants age. Largely due to the inspection programs in place today, these "surprises" are discovered in time to facilitate timely corrective actions.

During the last ten years, accelerated degradation associated with crack initiation was discovered in the stainless steel reactor vessel internals. The cause was determined to be stress corrosion cracking, assisted by fatigue and un-annealed weldments. A major research project was initiated by the industry and managed by EPRI to find solutions, mitigation techniques and new inspection methods to investigate, size, and analyze the cracks. Just recently another new issue emerged concerning the cracking of Alloy 600 and similar Inconel alloys. This also is attributed to stress corrosion cracking, aggravated by the unique water environment (high hydrogen levels and borated water) in the PWR reactors. As before, the industry convened a large task force to deal with the issue and EPRI again is managing the project for the plant owners. These two projects and others are now combined under the EPRI Materials Research Program (MRP).

Code and Standards Perspective of Aging Management

In principle, Codes and Standards are voluntary, unless mandated by a government authority. The ASME Boiler and Pressure Vessel Code (ASME-BPVC) is mandated by the state authorities and the NRC for safety related pressure vessels, while the Electrical

Code (IEEE) and Fire Protection Codes are enforced by national building codes (NFPA). The American Concrete Institute Codes are mandated by the building codes for residential and commercial construction, however for power plants and other industrial facilities the Engineer/Designer is responsible for Code compliance. For the safety related portion of the nuclear plant, the USNRC mandates certain ACI Codes, including ACI-349. A brief description of the code activities involving aging management is presented below.

ASME-BPVC PLEX Working Group

Section XI, "Inservice Inspection of Nuclear Power Plant Components" of the ASME Boiler Code is the applicable Code specifying inspection and testing requirements for the nuclear plant components, as well as frequency of inspections, personnel qualifications and inspection techniques to be applied. A special working group was established within Section XI to accommodate the eventual integration of aging management into the Code. As a first action, the committee removed the 40-year inspection schedule (four 10-year cycles) from the Code to permit continued 10-year intervals until the plant shuts down for decommissioning. In the interim the Working Group monitors technical issues as they emerge from the license renewal process for future integration. The Code does not react to new issues very quickly and purposely takes its time to test implementation problems before codifying them.

IEEE Working Group for Aging Management of Electrical and I&C Equipment

The Institute of Electrical and Electronics Engineers (IEEE) generated a guide for aging management of electrical and instrumentation equipment, P-1205 (draft), "IEEE Guide for Assessing, Monitoring and Mitigating Aging Effects on Class IE Equipment Used in Nuclear Power Generating Stations". The guide contains a comprehensive aging effects and mechanisms matrix and the associated effective aging management methods. It is not certain if this guide was ever formally issued.

ACI Standards for Evaluation of Existing Concrete Structures

The American Concrete Institute (ACI) had a working condition survey standard for concrete inservice since 1968, ACI-201.1R, "Guide for Making a Condition Survey of Concrete Inservice". The Code addresses some 38 degradation effects, including ten types of cracking. For most of the degradation effects, reference photographs are provided for the inspector to discern the exact nature of the defects. The code has been updated a number of times, the 1996 version being the latest. The code has been widely in use for municipal and public use structures (garages, bridges, event buildings, etc), but has also been applied to power plants, including the nuclear facilities.

More recently, ACI issued a new Code with specific application to safety related structures, ACI-349-3R, "Evaluation of Existing Nuclear Safety Related Concrete Structures". In addition to the condition survey requirements as defined in ACI-201, this standard provides definitive acceptance criteria at two levels, Acceptance without further evaluation and acceptance with review. The acceptance criteria for concrete inspections are provided in Table 11.

Table 11: *Concrete Inspection Acceptance Criteria (from ACI-349), Edited*

Concrete Defect Description	Acceptance Criteria Without Review	Acceptance Criteria With Review
Leaching and Chemical Attack	None permitted	None permitted
Abrasion, Corrosion, Cavitation	None permitted	Evaluate Defects
Drummy Areas, Poor Concrete	None permitted	<Cover Concrete
Popouts, Voids	<20mm diameter or Equiv. Area	<50mm diameter or Equiv. Area
Scaling	<5mm in depth	<30mm in depth
Spalling	<10mm in depth, <100mm in any dimension	<20mm in depth, <200mm in any dimension
Passive Cracks	<04mm in width	<1.0mm in width
Passive Deflection, Settlement	None permitted	Within design limits
Loss of Coatings	<4000mm^2 for any area	>4000mm^2 for any area
Leakage	None permitted	Evaluate any leakage

Lessons Learned from the Initial License Renewals

The license renewal process has been a 25-year learning curve. The initial version of the Rule in 1991 was found to be open-ended with an overwhelming program scope. The nuclear industry and the USNRC staff identified many problems with the initial Rule. The amended Rule in 1995 established a regulatory process that is simpler, more stable, and more predictable than the initial License Renewal Rule. It put the focus of the license renewal assessment on the licensees aging management activities concerning passive and long-lived SSCs. It also clarified the focus on managing the adverse effects of aging rather than identification of all aging mechanisms. The changes to the integrated plant assessment (IPA) process were to make it simpler and more consistent with the revised focus on passive, long-lived systems, structures and components. However there remained a number of areas where further improvements were needed in the application process.

In the late 1990's the Calvert Cliffs plant announced its plan to file an application using the revised Rule and the NEI license renewal application guide, NEI 95-10. NEI 95-10 provides an approach that the USNRC has found to be acceptable and has endorsed for implementing the requirements of the License Renewal Rule. The guidelines in the NEI 95-10 report are based on industry experience in implementing License Renewal Rule.

The review of the Calvert Cliffs applications by the USNRC staff revealed some serious problems. These included the fact the staff had very little guidance, no training, and a diverse view of what the regulations actually meant. Also, questions were raised with respect to the license renewal application costs, utility commitment, and effectiveness of the Rule. Senior management from both the USNRC and the nuclear industry worked to address these and other weaknesses with the license renewal process. This involved numerous site visits to familiarize the USNRC staff with site conditions and to conduct scope audits.

It became apparent that much of the information to be developed for an application is of a generic nature. It was determined that standards and guidance were needed to avoid unnecessary duplication of work. Guidance was also needed to avoid technical inconsistencies so that there are not different interpretations of the technical findings and conclusions from one application reviewer to another.

To address these and other issues the USNRC and the nuclear industry developed a number of guidance documents. One of the key documents has been the Generic Aging Lessons Learned (GALL) Report (NUREG-1801). The GALL report provides a template of aging management programs that have been determined to be acceptable by the USNRC to manage the aging effects of safety critical passive and long-lived SSCs. The GALL Report documents the USNRC's basis for determining which existing programs are adequate without modification and which existing programs should be augmented for license renewal. A complimentary Standard Review Plan (NUREG-1800) was developed as a guide to the USNRC staff for their review of the application information.

Strong emphasis has been placed on training NRC staff and plant owners to assure that all stakeholders are aware of the process, requirements, tools and reference guides. The NRC implemented an extensive training program for their staff members and assigned additional inexperienced staff to their site audit teams to observe and learn the process. Training modules also were developed by the owners groups and EPRI to be conducted at the plant sites for different levels of staff, management briefings and working level indoctrinations.

The next license renewal applicants were able to use these guidance documents in the development of their applications. Major cost reductions were realized with the streamlined process. Savings were estimated to be in the range of 50% to 75% with respect to the Calvert Cliffs project costs. Further improvements were initiated by the USNRC to shorten the review process from three years to less than two years, to deal with staff shortages and reflect the learning curve. The nuclear industry and NEI also sponsored development of the Aging Management Tools, a commitment database (to assure that applicants do not over-commit or fail to address previous USNRC issues), and a searchable database for NRC generic communications.

The lessons learned from these efforts and the continued review process has been incorporated into the latest revision of the GALL report and the Standard Review Plan. The process has matured to a point were the USNRC has been able to review multiple plant applications in parallel. Utilities have seen major cost and schedule reductions for the license renewal process; fewer site visits and experienced significantly less interaction with the USNRC during the review process.

Some to the key documents that are used by both the licensees and the USNRC during the license renewal process are listed in Table 12. These are all "living documents". Revised versions of the reports are routinely produced that incorporate changes based on experience gained from numerous license renewal application reviews by USNRC staff and from insights identified by the industry. For example, the, NEI 95-10 is currently in its sixth revision.

Table 12: *License Renewal Support and Guidance Documents*

Document Title	Document Identifier
Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants	NUREG-1800 (USNRC)
Generic Aging Lessons Learned (GALL) Report	NUREG-1801 (USNRC)
Standard Format and Content for Applications to Renew Nuclear Power Plant Operating Licenses	Regulatory Guide 1.188 (USNRC)
License Renewal Inspections	Inspection Manual 71002 (USNRC)
Policy and Guidance for License Renewal Inspection Programs	MC-2516 (USNRC)
Industry Guidelines for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule	NEI 95-10 (Nuclear Energy Institute)

Reaching Process Consensus among Stakeholders

As described above, the license renewal process has undergone substantial evolution. This implies recognition of the need to and willingness to change by all parties involved. Pressure was applied on the regulator to keep the process on track, simplify it and make it effective for all stakeholders. The mistakes made with the initial rule could not be repeated and a stable and workable process had become essential for success. Such a proven process also lends itself to standardization, further assuring consistency and efficiency. One of the key concerns with new regulations is the threat of "Rule Creep", that is the ever-changing interpretations of the regulations, issuance of new guidance, raising of new issues, different treatment of the same issue for other applicants and the constant desire to invent new wheels. In this case, the NRC and utilities were jointly motivated to develop a streamlined and stable methodology. The development of the GALL report and NEI license renewal Guide, NEI 95-10, are considered major tools to achieve those objectives.

The process has by no means found its end point, additional lessons learned, improvements and experience feedback are being monitored and revisions of the key references are planned to capture process changes. The most recent evidence of the continuing consensus evolution is an EPRI project to prepare so-called "Road Maps" for generic technical issues and associated aging management programs. This project evolved from the tallying and review of individual plant commitments and to sort those that are common to many plants and therefore deserve identical treatment and resolution. These road maps are to assist plant owners to develop implementation tasks for their license renewal commitments at least costs and assuring acceptability of implementation. The road maps also identify technical issues that are not fully resolved yet and require research to facilitate task implementation prior to the start of the license renewal period. The NRC is expected to audit these implementation activities in the future and they are tracking compliance with the applicant's commitments.

Another method to communicate current development, lessons learned and ideas of process improvement is facilitated through frequent workshops sponsored by the NRC and the industry. These workshops encourage presentations from all stakeholders and the public to solicit input and opinions. They are also a vehicle to share information with management, vendors, suppliers of services, inspectors, public members and other interested parties. All or most of the license renewal information, including the complete application packages, USNRC application reviews (SER), rules and regulations and guidance documents (GALL, SRP-LR, NEI-95-10, Regulatory Guides, Interim Staff Guidance) are available on the USNRC website (www.nrc.gov).

Life Extension Implementation at the Plants

The Two-Step Process

Life Extension for a plant is considered a two-step process. The initial step is to secure regulatory approval through license renewal application process. The second step is to actually implement life extension for the plant. Although the approval of a license renewal allows continued operation for 20-years it does not require such operation. The decision to actually operate beyond the current license period is up to the licensee. It is dependent on such factors as power generation planning, economic justification, and prevailing condition of the plant.

The aging management requirements of the license renewal application only apply to the safety-related scope under the License Renewal Rule – about one-third of the plant equipment. In order to prepare the plant for life extension, the remaining power production part of the plant has to be upgraded and evaluated to assure that the equipment can support reliable operation for an extra 20 years. Many plants will wait until about five years before the extended license becomes effective (at year 35 of the plant life) to avoid large capital investments that may become stranded if the plant owners decide not to implement life extension. Often these objectives are compromised, because the plant may need a new turbine generator or main transformer at year 34, without life extension such an investment would not be cost beneficial such that the extended life period is needed in the cost benefit analysis.

Proactive Implementation Tasks

While most of the license renewal commitments for the plant apply only for the extended operating period, there are a number of preparatory and mitigative actions taken by the plants to reduce future costs and to collect the information needed for future assessments. The following are some of the proactive, diagnostic, preventive, predictive and investigative activities performed by plants in preparation for license renewal:

- Temperature Survey of Spaces for EQ
  - Initial survey with Pyrometer or Thermography to locate "Hot Spots", actual temperature variations within the space, room or enclosure, locations with temporary elevated temperature and containing vulnerable electrical equipment
- Fatigue Cycle Counting and Monitoring
  - Simple cycle counting and transient categorization to be compared to the design basis assumptions and projected for 60 years. Thermal transient monitoring to determine the rate of transients for future reclassification and margin hunting.
- Biological Essays (Tests) of Water Sources
  - Sampling and testing for MIC of all water sources (Service Water, raw water, demineralized water, closed loops, sumps, storage tanks, lube oil, fuel oil)

- Visual Inspection of Inaccessible Areas
  - When opening up equipment (pumps, valves, heat exchangers, tanks/vessels) or removing insulation, perform a visual (VT-1 or VT-3) inspection of the normally inaccessible surfaces and record the conditions (corrosion, cracking, loss of material, staining, etc). When excavating buried/embedded pipe, steel and concrete structures, trenches, cable ducts, perform a VT-1 or VT-3 and take good pictures of the normally inaccessible surfaces.
- Wall Thickness Measurements
  - When possible, conduct sample UT wall thickness measurements on carbon steel piping, valve bodies, pump casings, heat exchanger and vessel shells, tank walls and bottoms, etc. Identify and record abnormal conditions.
- Underwater Inspections
  - When using divers in the intake, fuel pools, etc, train divers for VT-1 examinations and debrief afterwards. Document conditions and take photos if possible.
- Soil and Groundwater Tests
  - Take soil and groundwater samples and test for chlorides, sulfates, silica, cement paste, iron oxides. Take samples as near to the structure as possible from test wells, borings, and excavations. Monitor groundwater level and variations at least over a few years.
- Settlement Monitoring
  - If the plant sits on soil or piles, consider installing, reactivating or updating the settlement monitoring system for the principal structures (Containment, Auxiliary or Reactor Building, Intake).
- Air Sampling and Testing
  - Sample and test the external plant air to determine the extent and type of air pollution at the site, measure chlorides, CO, SOX, NOX, particulates to establish aggressiveness. For ocean plants, measure the concentration of NaCl (salt) for various weather and wind conditions in the ventilation intakes.
- Beltline Material Surveillance
  - Review the material test coupon withdrawal schedule and make adjustments as early as possible to accommodate a 60-year (and possibly 80 year) operating period. Consider reinsertion of the material, using miniaturization and reconstitution of the coupons for future embrittlement tests.

License Renewal Commitment Implementation after Year 40

Once the plant approaches the end of the current operating license and decided that economics dictate continuation of operation and that an extended life is warranted and desirable, the commitments made in the license renewal application become mandatory and full implementation must be achieved before the plant can continue to operate past

40 years. Plants consider it unwise to wait to the last minute, particularly for new inspection programs, such as certain one-time inspections, where surprises could occur in that unexpected degradation is found. In such case, the aging management program for the affected components would not be effective and would require changes and regulatory review prior to continued operation. Other programs that merely require procedure changes or administrative actions could be delayed to the last year. Another aspect of the implementation process is to consider the generic guidance developed by NEI and EPRI, such as the “Road Maps” discussed earlier. It is important to implement tasks that are acceptable to the regulator, feature the attributes and requirements as well as scope committed to in the application.

Typically a plant will have between 200 and 400 individual license renewal tasks to implement. To assure that the tasks are all properly scheduled for completion and documentation is generated, a computerized database is normally used to track responsibility, schedule, completion status and associated design and quality assurance records/references. Many tasks require follow-up actions or re-inspections at a predetermined interval and inspection results must be evaluated and documented. The plant has to be able to verify implementation to the regulator’s onsite inspectors.

A new Appendix to the License Renewal Guide, NEI 95-10, has been drafted and issued. The purpose of this Appendix is to provide guidance to utility personnel for the follow-up actions after receipt of a renewed license.

In parallel, the USNRC has also developed inspection guidance for their onsite inspectors, as well as training programs to get ready for the extended operating period. The applicable inspection program policy document is embodied in the USNRC’s “Policy and Guidance for License Renewal Inspection Programs”, MC-2516. Because of its relevance an edited copy of this policy document has been included in Appendix E.

International Applications and Interaction

The US has taken an active role in transferring the aging management and life extension technology to other countries and international organizations. This has taken place at all levels, starting with the NRC participation in IAEA working groups to draft international standards, to individual consultants assisting foreign countries and organizations to develop their own programs. Many international conferences on nuclear technology, such as ICONE, SMIRTand IPLEX, have carried specific sessions to address life extension, aging management and operational issues. US corporations and government agencies have extensively participated in these sessions and shared their experiences and processes with the international community. Additionally, the USNRC website provides most of the regulatory guidance documents and licensing proceedings without restrictions. The following specific examples of technology transfer provide just a small piece of the word wide application of this US technology.

- The Spanish regulator required the Spanish utilities to implement the Maintenance Rule as defined in the US regulations. Assistance was provided to the utilities in shaping a program tailored to their needs and unique circumstances. Spanish regulatory representatives cross trained with the USNRC in their Washington headquarters to learn about the implementation process and the procedures.
- The IAEA relied on US participation to draft License Renewal and Aging Management standards, using US precedents, methodology and references. This has led to the development of international policy documents and generation of a number of Aging Management Standards (Containment, Reactor Vessel)
- Japan having some of the oldest nuclear plants in the world, has benefited from the early aging studies conducted in the US. Aging analysis reports have been made available to Japanese utilities through a number of technology exchange channels.
- South Korea has applied US life extension technology to their plants, both in the aging evaluations and degradation assessments/inspections.
- France (EDF) through a technology exchange agreement with EPRI has acquired the US life extension technology and life cycle management processes. A number of training seminars and workshops were held in France to present the technology.
- Switzerland, through their utility owners group, has made use of the life extension and aging management technology, specifically the identification of applicable aging effects and mechanisms and their aging management programs. Following a successful national referendum on the continuation of nuclear power, the Swiss plants are preparing their license renewal applications.

Lessons Learned – Possible Petroleum Industry Application

For over fifteen years the USNRC and the nuclear industry have been continuously refining both the license renewal requirements and the renewal process. There are many aspects of these aging management and life extension efforts and the lessons that have been learned that can be of potential value to the PSA and the Norwegian petroleum industry.

Aging Research Information

The wealth of aging related information produced by the NPAR and industry aging research programs remains a useful resource for both nuclear and non-nuclear organizations. Although the aging studies examined SSCs with respect to their operation in the nuclear plants, much of the aging degradation and aging management information is applicable to the petroleum and other industrial sectors.

Continuous Improvement

Over the years both the USNRC and the industry have been working to make the license renewal requirements and the renewal process more efficient and effective. For example, the initial version of the Rule did not provide a predictable nor stable process – it was too open ended with too broad a scope. It was determined that many aging effects were already adequately addressed during the initial operating license period. Also, the initial Rule did not allow sufficient credit for existing programs, particularly those under the USNRC Maintenance Rule, which help manage plant aging phenomena as part of the on-going maintenance program tasks.

The resulting revised Rule established a simpler, more stable, and more predictable regulatory process. The key changes that were made included:

- focusing on the adverse effects of aging rather than identification of all aging mechanisms – identification of individual aging mechanisms is not required
- simplifying the integrated plant assessment process and madding it consistent with the revised focus on the detrimental effects of aging
- adding an evaluation of time-limited aging analyses (TLAA)
- requiring only passive, long-lived structures and components to be subject to an aging management review for license renewal – removing active SSCs from license renewal

Passive versus Active SSCs

An important aspect of the US nuclear plant life extension requirements is the distinction between passive and active systems, structures, and components. Passive SSCs are those that do not move to function (such as, structures, heat exchangers, cables, valve and pump bodies, and piping). Their age related degradation can only be monitored and trended by performing periodic condition assessments (such as inspections, testing, and measurements).

By focusing the license renewal process on safety critical passive and long-lived components the process has been reduced to a manageable proportions – licensees are not required to consider all SSCs in order to justify extended operations.

Guidance and Training

One of the key lessons has been the need to provide clear guidance and support to all involved parties. Both the USNRC and the industry have developed guidance documents to assist in the development of aging management programs, the preparation of the renewal application, and the review of the application. As lessons are learned these guidance documents are revised to capture new insights or address emerging issues. Along with the guidance documents, training programs and support activities have greatly reduced the time and expense in preparing, reviewing, and approving the license renewal applications. The training must be supplemented with guides, pilot studies, working examples, and procedures to assure consistency of application.

Integration of Aging Management Program Requirements

From the description of the many diverse aging management programs it becomes clear that plants have a difficult time to integrate all the different requirements and to avoid duplication and non-effective maintenance tasks. Too much maintenance can lead to reliability and availability concerns and it is necessary to strive for an adequate balance. Other drivers are manpower, costs, prioritization of activities and consolidation of tasks. As part of the Maintenance Rule, the plants already have established a 13-week schedule, that is each system or train (where systems have redundant trains) will be taken out of service for one week every 13 weeks, or four times a year. During this one-week system outage, all the preventive and corrective maintenance tasks are to be completed, including invasive inspections, tests, calibrations, repairs and replacements. Once license renewal activities begin, additional tasks will have to be squeezed into the maintenance week, likely at the expense of other similar tasks.

Long-term Maintenance Strategy

When contemplating aging management for a facility, the useful life expectancy and associated planning horizon must be established first, to provide a basis for the long-term maintenance strategy. The ultimate operating life has a profound impact on the selection of appropriate and economic maintenance alternatives. It is prudent to link asset management to maintenance strategy with an objective to preserve the assets as long as economically feasible. A lesson learned from the aging management projects is that most components can be replaced and that good aging management can preserve structures for decades if not centuries (the B-52 aircraft are over 50 years old and are still flying).

Reducing Component Failures

No other maintenance action taken in the plant will have as much impact on equipment reliability and plant availability as reducing the failure rates of components. The plant or system performance cannot be better than the worst performing critical component. All efforts must therefore be directed to identify incipient failures, precursors and age related degradation. This implies that inspections and diagnostics must be employed in areas where failure knowledge and prediction is inadequate. In general plants are not aggressive enough to reduce failures and to invest in predictive maintenance. Even though some plants have a "Zero Failure Tolerance" policy, when it comes to making investments, replacements are preferred.

Effectiveness of Condition Monitoring

It is not unusual to find that plants have implemented predictive maintenance tools to monitor equipment conditions, but the diagnostics are not effective in preventing failures. One example is vibration monitoring of rotating equipment, when data is read infrequently (once a month) with portable equipment. Bearing degradation can progress, and often will, from minor imbalance to catastrophic failure within minutes or hours. Continuous monitoring with alert and warning levels is significantly more effective. Another example is oil analysis and ferrography performed at certain intervals is mostly used to justify an increase in the oil change interval. Installing oil reservoir breather caps and filters will be more effective to keep contaminants out of the oil. Thermography has slowly made inroads in detecting degradation and incipient failures, even though the surveys are done typically only annually and only for readily accessible equipment. More aggressive and effective thermography can be performed for electrical equipment inside enclosures, using infrared windows. Enclosed motors also can be surveyed internally using infrared windows on the casing to measure rotor and stator, slip ring and bearing temperatures to identify hot spots.

Establishing Appropriate Inspection Procedures

The two major questions concerning an effective inspection program are: What and how often to inspect? For components such as cable, piping, valves, pumps, motors a sampling program is the most effective means of inspection. Sampling rates must be representative with respect to component size, vendor, materials, service and environmental exposure. An example is to start with a 10% sampling rate and decreasing the rate after five years if nothing is found. Or doubling the rate if defective equipment is found. If more than one deficiency is found, a 100% inspection would be justified.

If a risk analysis is available, component selection and prioritization can be made by using risk measures. If aging evaluations have been performed, the most vulnerable components and locations should be known and become the focus of inspections. The frequency of inspections depends on the degradation one is looking for. If the known degradation is a fairly rapid and aggressive process, inspection periods of one to two years are not uncommon, while inspections of steel and concrete structures are undertaken at ten-year intervals. If acceptable defects are found or if repairs have been performed, the inspection periods should be shortened, commensurate with the rate of degradation or on an annual basis.

Just because nothing has been found for 20 or 30 years does not imply that degradation is absent, it may just be slow or takes a long time to crack initiation and propagation. The most troubling degradation issues in the nuclear plants became apparent after more 20 years of operation and exposure.

Aging Management of Inaccessible Equipment

A major concern in the license renewal process is equipment that is not readily accessible to inspection, testing or diagnostics. Underground piping and cable, embedded steel, underwater structures are examples of these cases. Unique programs were developed to deal with these components and to assure that degradation is adequately managed. Onetime inspections, selected excavations, use of test coupons and monitoring of the service environment (soil and water chemistry, evidence of corrosion products) were employed to indicate when and where degradation becomes active. Managing these inaccessible components and structures should be a priority, because replacement and repair is not usually a feasible option.

Sharing Experiences

An effective failure reduction strategy is to access, review and analyze equipment failures at other facilities. Problems and difficulties at older facilities or those that have greater operating hours can be a valuable source of leading indicators of what to watch out for. Generic failures may point out particularly vulnerable parts, impact of abnormal operation, failure indicators, methods of detection and actual service hours to failure.

Another important source of information is gained by monitoring of other plant's experience and programs to identify those activities that work and those that do not work. The sharing of best practices, however has been impeded by the deregulation of the nuclear power industry. Unfortunately, in certain cases, information that provides an economic advantage to one plant becomes a valuable commodity that is likely not to be shared with others.

Manufactures usually do not have a good understanding of the operational performance of their equipment in the field and are only performing root cause assessments when they receive a warranty claim. Maintenance recommendations from the manufacturer must be taken with great caution and only if a technical basis exists for their recommendations, such as operational failure rate trends and component life expectancies.

Pilot Projects

When attempting to create new regulations with complex processes, it is imperative to test the regulations and processes in a real application environment. The first License Renewal rule failed as a result of applying it to a demonstration project. All stakeholders must participate in this test program to understand the implications and be willing to search for acceptable compromise. The revised rule was a success because of frequent interaction among the stakeholders, participation of and guidance from senior management representatives and a willingness to change and adapt during the development process.

Properly Quantify Consequential Failure Costs

Often when cost benefit analyses are performed to justify corrective or preventive actions following equipment failures, the consequential failure costs are not adequately incorporate into the analyses. This can lead to erroneous assumptions and conclusions.

Failure costs can include lost production, personnel injury, lost work time, and medical costs. The more serious the failure the greater the impact on the plant and the organization. Some plants have been forced to shutdown for several years because of equipment failures and human errors. It is therefore important to identify and quantify the consequential failure costs to support reliable conclusions and to justify implementation of a predictive maintenance and effective aging management strategy

Quantify Consequential Failure Costs

Often when cost benefit analyses are performed to justify corrective or preventive actions following equipment failures, the consequential failure costs are not adequately incorporate into the analyses. This can lead to erroneous assumptions and conclusions. As stated earlier, the value of one day's lost power production approaches one Million Dollars for most plants. In addition, some failures cause personnel injury, lost work time, medical costs and inquiries by the safety authorities. Other failure consequences may even be more drastic, including fires, flooding, steam escape, explosions, radioactive contamination or releases. The more serious the failure, the more impact there will be on the corporate well being, from an impact on the stock price, annual dividend and earnings, public image and potential regulatory actions and fines. Some plants have been forced to shutdown for periods up to two years, because of equipment failures and human errors. It is therefore important to identify and quantify the consequential failure costs to support reliable conclusions and to justify implementation of a predictive maintenance and effective aging management strategy.

Conclusions

The aging management and life extension process for the US nuclear industry has been refined and improved over the years. It has become an efficient and effective method to ensure that the nuclear plants in the United States can be safely operated beyond their original 40-year operating license. By dividing the safety critical systems, structures, and components into passive and active categories the industry and regulator have reduced the potentially overwhelming analysis effort to a reasonable and manageable size.

By working together, the nuclear industry and the US Nuclear Regulatory Commission (USNRC) have been able to technically justify life extension. The process has been structured to not be an economic or resource burden on either the licensees or the USNRC. However, all parties are continually reviewing the process and results to identify where improvements can be made.

The process has been selected as a viable method by many international regulatory and nuclear industry organizations, including those in Spain, Taiwan, and Korea. The International Atomic Energy Agency in Vienna has also adopted the process as the model for ensuring safe extended life operations.

The aging management and life extension process can be easily adapted to other industries. The development strategy, research material, specific elements of the process, and many of the lessons learned can all be of potential value to the PSA and Norwegian petroleum industry in ensuring safe extended operations of the facilities.

Appendices

A The Maintenance Rule: Title 10 of the US Code of Federal Regulations, Part 50.65 (10 CFR 54.65)

B The License Renewal Rule: Title 10 of the US Code of Federal Regulations, Part 54 (10 CFR Part 54)

C USNRC Guidance Concerning Aging Effects and Aging Mechanisms

D Aging Management Program Example – Concrete Structures Monitoring: GALL Report-(NUREG-1801 Vol 2)

E License Renewal Inspection Policy and Guidance: USNRC Inspection Manual Chapter (MC) 2516 – Policy and Guidance for the License Renewal Inspection Programs

F Nuclear Related Aging Management and Life Extension Abbreviations and Acronyms

G Bibliography of Selected Nuclear Aging Management and Life Extension Reports

Appendix A

The Maintenance Rule

Title 10 of the US Code of Federal Regulations, Part 50.65 (10 CFR 54.65)

Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants

The requirements of this section are applicable during all conditions of plant operation, including normal shutdown operations.

(a)(1) Each holder of a license to operate a nuclear power plant under Secs. 50.21(b) or 50.22 shall monitor the performance or condition of structures, systems, or components, against licensee-established goals, in a manner sufficient to provide reasonable assurance that such structures, systems, and components, as defined in paragraph (b), are capable of fulfilling their intended functions. Such goals shall be established commensurate with safety and, where practical, take into account industry-wide operating experience. When the performance or condition of a structure, system, or component does not meet established goals, appropriate corrective action shall be taken. For a nuclear power plant for which the licensee has submitted the certifications specified in Sec. 50.82(a)(1), this section only shall apply to the extent that the licensee shall monitor the performance or condition of all structures, systems, or components associated with the storage, control, and maintenance of spent fuel in a safe condition, in a manner sufficient to provide reasonable assurance that such structures, systems, and components are capable of fulfilling their intended functions.

(2) Monitoring as specified in paragraph (a)(1) of this section is not required where it has been demonstrated that the performance or condition of a structure, system, or component is being effectively controlled through the performance of appropriate preventive maintenance, such that the structure, system, or component remains capable of performing its intended function.

(3) Performance and condition monitoring activities and associated goals and preventive maintenance activities shall be evaluated at least every refueling cycle provided the interval between evaluations does not exceed 24 months. The evaluations shall take into account, where practical, industry-wide operating experience. Adjustments shall be made where necessary to ensure that the objective of preventing failures of structures, systems, and components through maintenance is appropriately balanced against the objective of minimizing unavailability of structures, systems, and components due to monitoring or preventive maintenance.

(4) Before performing maintenance activities (including but not limited to surveillance, post-maintenance testing, and corrective and preventive maintenance), the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities. The scope of the assessment may be limited to structures, systems, and components that a risk-informed evaluation process has shown to be significant to public health and safety.

(b) The scope of the monitoring program specified in paragraph (a)(1) of this section shall include safety related and nonsafety related structures, systems, and components, as follows:

(1) Safety-related structures, systems and components that are relied upon to remain functional during and following design basis events to ensure the integrity of the reactor coolant pressure boundary, the capability to shut down the reactor and maintain it in a safe shutdown condition, or the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposure comparable to the guidelines in Sec. 50.34(a)(1), Sec. 50.67(b)(2), or Sec. 100.11 of this chapter, as applicable.

(2) Nonsafety related structures, systems, or components:

(i) That are relied upon to mitigate accidents or transients or are used in plant emergency operating procedures (EOPs); or

(ii) Whose failure could prevent safety-related structures, systems, and components from fulfilling their safety-related function; or

(iii) Whose failure could cause a reactor scram or actuation of a safety-related system.

(c) The requirements of this section shall be implemented by each licensee no later than July 10, 1996.

Appendix B

The License Renewal Rule

Title 10 of the US Code of Federal Regulations, Part 54
(10 CFR Part 54)

Requirements for Renewal of Operating Licenses for Nuclear Power Plants

General Provisions

§ 54.1 Purpose.

This part governs the issuance of renewed operating licenses for nuclear power plants licensed pursuant to Sections 103 or 104b of the Atomic Energy Act of 1954, as amended (68 Stat. 919), and Title II of the Energy Reorganization Act of 1974 (88 Stat. 1242).

§ 54.3 Definitions.

(a) As used in this part,

Current licensing basis (CLB) is the set of NRC requirements applicable to a specific plant and a licensee's written commitments for ensuring compliance with and operation within applicable NRC requirements and the plant-specific design basis (including all modifications and additions to such commitments over the life of the license) that are docketed and in effect. The CLB includes the NRC regulations contained in 10 CFR Parts 2, 19, 20, 21, 26, 30, 40, 50, 51, 54, 55, 70, 72, 73, 100 and appendices thereto; orders; license conditions; exemptions; and technical specifications. It also includes the plant-specific design-basis information defined in 10 CFR 50.2 as documented in the most recent final safety analysis report (FSAR) as required by 10 CFR 50.71 and the licensee's commitments remaining in effect that were made in docketed licensing correspondence such as licensee responses to NRC bulletins, generic letters, and enforcement actions, as well as licensee commitments documented in NRC safety evaluations or licensee event reports.

Integrated plant assessment (IPA) is a licensee assessment that demonstrates that a nuclear power plant facility's structures and components requiring aging management review in accordance with § 54.21(a) for license renewal have been identified and that the effects of aging on the functionality of such structures and components will be managed to maintain the CLB such that there is an acceptable level of safety during the period of extended operation.

Nuclear power plant means a nuclear power facility of a type described in 10 CFR 50.21(b) or 50.22.

Time-limited aging analyses, for the purposes of this part, are those licensee calculations and analyses that:

(1) Involve systems, structures, and components within the scope of license renewal, as delineated in § 54.4(a);
(2) consider the effects of aging;
(3) Involve time-limited assumptions defined by the current operating term, for example, 40 years;
(4) Were determined to be relevant by the licensee in making a safety determination;
(5) Involve conclusions or provide the basis for conclusions related to the capability of the system, structure, and component to perform its intended functions, as delineated in § 54.4(b); and

(6) Are contained or incorporated by reference in the CLB.

(b) All other terms in this part have the same meanings as set out in 10 CFR 50.2 or Section 11 of the Atomic Energy Act, as applicable.

§ 54.4 Scope.

(a) Plant systems, structures, and components within the scope of this part are--

(1) Safety-related systems, structures, and components which are those relied upon to remain functional during and following design-basis events (as defined in 10 CFR 50.49 (b)(1)) to ensure the following functions--

(i) The integrity of the reactor coolant pressure boundary;

(ii) The capability to shut down the reactor and maintain it in a safe shutdown condition; or

(iii) The capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to those referred to in § 50.34(a)(1), § 50.67(b)(2), or § 100.11 of this chapter, as applicable.

(2) All nonsafety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of any of the functions identified in paragraphs (a)(1)(i), (ii), or (iii) of this section.

(3) All systems, structures, and components relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for fire protection (10 CFR 50.48), environmental qualification (10 CFR 50.49), pressurized thermal shock (10 CFR 50.61), anticipated transients without scram (10 CFR 50.62), and station blackout (10 CFR 50.63).

(b) The intended functions that these systems, structures, and components must be shown to fulfill in § 54.21 are those functions that are the bases for including them within the scope of license renewal as specified in paragraphs (a)(1) - (3) of this section.

[60 FR 22491, May 8, 1995, as amended at 61 FR 65175, Dec. 11, 1996; 64 FR 72002, Dec. 23, 1999]

§ 54.5 Interpretations.

Except as specifically authorized by the Commission in writing, no interpretation of the meaning of the regulations in this part by any officer or employee of the Commission other than a written interpretation by the General Counsel will be recognized to be binding upon the Commission.

§ 54.7 written communications.

All applications, correspondence, reports, and other written communications shall be filed in accordance with applicable portions of 10 CFR 50.4.

§ 54.9 Information collection requirements: OMB approval.

(a) The Nuclear Regulatory Commission has submitted the information collection requirements contained in this part to the Office of Management and Budget (OMB) for approval as required by the Paperwork Reduction Act (44 U.S.C. 3501 et seq.). The NRC may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. OMB has approved the information collection requirements contained in this part under control number 3150-0155.

(b) The approved information requirements contained in this part appear in §§ 54.13, 54.15, 54.17, 54.19, 54.21, 54.22, 54.23, 54.33, and 54.37.

[60 FR 22491, May 8, 1995, as amended at 62 FR 52188, Oct. 6, 1997; 67 FR 67100, Nov. 4, 2002]

§ 54.11 Public inspection of applications.

Applications and documents submitted to the Commission in connection with renewal applications may be made available for public inspection in accordance with the provisions of the regulations contained in 10 CFR Part 2.

§ 54.13 Completeness and accuracy of information.

(a) Information provided to the Commission by an applicant for a renewed license or information required by statute or by the Commission's regulations, orders, or license conditions to be maintained by the applicant must be complete and accurate in all material respects.

(b) Each applicant shall notify the Commission of information identified by the applicant as having, for the regulated activity, a significant implication for public health and safety or common defense and security. An applicant violates this paragraph only if the applicant fails to notify the Commission of information that the applicant has identified as having a significant implication for public health and safety or common defense and security. Notification must be provided to the Administrator of the appropriate regional office within 2 working days of identifying the information. This requirement is not applicable to information that is already required to be provided to the Commission by other reporting or updating requirements.

§ 54.15 Specific exemptions.

Exemptions from the requirements of this part may be granted by the Commission in accordance with 10 CFR 50.12.

§ 54.17 Filing of application.

(a) The filing of an application for a renewed license must be in accordance with Subpart A of 10 CFR Part 2 and 10 CFR 50.4 and 50.30.
(b) Any person who is a citizen, national, or agent of a foreign country, or any corporation, or other entity which the Commission knows or has reason to know is owned, controlled, or dominated by an alien, a foreign corporation, or a foreign government, is ineligible to apply for and obtain a renewed license.
(c) An application for a renewed license may not be submitted to the Commission earlier than 20 years before the expiration of the operating license currently in effect.
(d) An applicant may combine an application for a renewed license with applications for other kinds of licenses.
(e) An application may incorporate by reference information contained in previous applications for licenses or license amendments, statements, correspondence, or reports filed with the Commission, provided that the references are clear and specific.
(f) If the application contains Restricted Data or other defense information, it must be prepared in such a manner that all Restricted Data and other defense information are separated from unclassified information in accordance with 10 CFR 50.33(j).
(g) As part of its application, and in any event before the receipt of Restricted Data or classified National Security Information or the issuance of a renewed license, the applicant shall agree in writing that it will not permit any individual to have access to or any facility to possess Restricted Data or classified National Security Information until the individual and/or facility has been approved for such access under the provisions of 10 CFR Parts 25 and/or 95. The agreement of the applicant in this regard shall be deemed part of the renewed license, whether so stated therein or not.
[60 FR 22491, May 8, 1995, as amended at 62 FR 17690, Apr. 11, 1997]

§ 54.19 Contents of application--general information.

(a) Each application must provide the information specified in 10 CFR 50.33(a) through (e), (h), and (i). Alternatively, the application may incorporate by reference other documents that provide the information required by this section.
(b) Each application must include conforming changes to the standard indemnity agreement, 10 CFR 140.92, Appendix B, to account for the expiration term of the proposed renewed license.

§ 54.21 Contents of application--technical information.

Each application must contain the following information:
(a) An integrated plant assessment (IPA). The IPA must--

- (1) For those systems, structures, and components within the scope of this part, as delineated in § 54.4, identify and list those structures and components subject to an aging management review. Structures and components subject to an aging management review shall encompass those structures and components--
  - (i) That perform an intended function, as described in § 54.4, without moving parts or without a change in configuration or properties. These structures and components include, but are not limited to, the reactor vessel, the reactor coolant system pressure boundary, steam generators, the pressurizer, piping, pump casings, valve bodies, the core shroud, component supports, pressure retaining boundaries, heat exchangers, ventilation ducts, the containment, the containment liner, electrical and mechanical penetrations, equipment hatches, seismic Category I structures, electrical cables and connections, cable trays, and electrical cabinets, excluding, but not limited to, pumps (except casing), valves (except body), motors, diesel generators, air compressors, snubbers, the control rod drive, ventilation dampers, pressure transmitters, pressure indicators, water level indicators, switchgears, cooling fans, transistors, batteries, breakers, relays, switches, power inverters, circuit boards, battery chargers, and power supplies; and
  - (ii) That are not subject to replacement based on a qualified life or specified time period.
- (2) Describe and justify the methods used in paragraph (a)(1) of this section.
- (3) For each structure and component identified in paragraph (a)(1) of this section, demonstrate that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation.

(b) CLB changes during NRC review of the application. Each year following submittal of the license renewal application and at least 3 months before scheduled completion of the NRC review, an amendment to the renewal application must be submitted that identifies any change to the CLB of the facility that materially affects the contents of the license renewal application, including the FSAR supplement.
(c) An evaluation of time-limited aging analyses.

(1) A list of time-limited aging analyses, as defined in § 54.3, must be provided. The applicant shall demonstrate that--

(i) The analyses remain valid for the period of extended operation;

(ii) The analyses have been projected to the end of the period of extended operation; or

(iii) The effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

(2) A list must be provided of plant-specific exemptions granted pursuant to 10 CFR 50.12 and in effect that are based on time-limited aging analyses as defined in § 54.3. The applicant shall provide an evaluation that justifies the continuation of these exemptions for the period of extended operation.

(d) An FSAR supplement. The FSAR supplement for the facility must contain a summary description of the programs and activities for managing the effects of aging and the evaluation of time-limited aging analyses for the period of extended operation determined by paragraphs (a) and (c) of this section, respectively.

§ 54.22 Contents of application--technical specifications.

Each application must include any technical specification changes or additions necessary to manage the effects of aging during the period of extended operation as part of the renewal application. The justification for changes or additions to the technical specifications must be contained in the license renewal application.

§ 54.23 Contents of application--environmental information.

Each application must include a supplement to the environmental report that complies with the requirements of Subpart A of 10 CFR Part 51.

§ 54.25 Report of the Advisory Committee on Reactor Safeguards.

Each renewal application will be referred to the Advisory Committee on Reactor Safeguards for a review and report. Any report will be made part of the record of the application and made available to the public, except to the extent that security classification prevents disclosure.

§ 54.27 Hearings.

A notice of an opportunity for a hearing will be published in the Federal Register in accordance with 10 CFR 2.105. In the absence of a request for a hearing filed within 30 days by a person whose interest may be affected, the Commission may issue a renewed operating license without a hearing upon 30-day notice and publication once in the *Federal Register* of its intent to do so.

§ 54.29 Standards for issuance of a renewed license.

A renewed license may be issued by the Commission up to the full term authorized by § 54.31 if the Commission finds that:

(a) Actions have been identified and have been or will be taken with respect to the matters identified in Paragraphs (a)(1) and (a)(2) of this section, such that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the CLB, and that any changes made to the plant's CLB in order to comply with this paragraph are in accord with the Act and the Commission's regulations. These matters are:

(1) managing the effects of aging during the period of extended operation on the functionality of structures and components that have been identified to require review under § 54.21(a)(1); and

(2) time-limited aging analyses that have been identified to require review under § 54.21(c).

(b) Any applicable requirements of Subpart A of 10 CFR Part 51 have been satisfied.

(c) Any matters raised under § 2.335 have been addressed.

[69 FR 2279, Jan. 14, 2004]

§ 54.30 Matters not subject to a renewal review.

(a) If the reviews required by § 54.21 (a) or (c) show that there is not reasonable assurance during the current license term that licensed activities will be conducted in accordance with the CLB, then the licensee shall take measures under its current license, as appropriate, to ensure that the intended function of those systems, structures or components will be maintained in accordance with the CLB throughout the term of its current license.

(b) The licensee's compliance with the obligation under Paragraph (a) of this section to take measures under its current license is not within the scope of the license renewal review.

§ 54.31 Issuance of a renewed license.

(a) A renewed license will be of the class for which the operating license currently in effect was issued.

(b) A renewed license will be issued for a fixed period of time, which is the sum of the additional amount of time beyond the expiration of the operating license (not to exceed 20 years) that is requested in a renewal application plus the remaining number of years on the operating license currently in effect. The term of any renewed license may not exceed 40 years.

(c) A renewed license will become effective immediately upon its issuance, thereby superseding the operating license previously in effect. If a renewed license is subsequently set aside upon further administrative or judicial appeal, the operating license previously in effect will be reinstated unless its term has expired and the renewal application was not filed in a timely manner.
(d) A renewed license may be subsequently renewed in accordance with all applicable requirements.

§ 54.33 Continuation of CLB and conditions of renewed license.

(a) Whether stated therein or not, each renewed license will contain and otherwise be subject to the conditions set forth in 10 CFR 50.54.
(b) Each renewed license will be issued in such form and contain such conditions and limitations, including technical specifications, as the Commission deems appropriate and necessary to help ensure that systems, structures, and components subject to review in accordance with § 54.21 will continue to perform their intended functions for the period of extended operation. In addition, the renewed license will be issued in such form and contain such conditions and limitations as the Commission deems appropriate and necessary to help ensure that systems, structures, and components associated with any time-limited aging analyses will continue to perform their intended functions for the period of extended operation.
(c) Each renewed license will include those conditions to protect the environment that were imposed pursuant to 10 CFR 50.36b and that are part of the CLB for the facility at the time of issuance of the renewed license. These conditions may be supplemented or amended as necessary to protect the environment during the term of the renewed license and will be derived from information contained in the supplement to the environmental report submitted pursuant to 10 CFR Part 51, as analyzed and evaluated in the NRC record of decision. The conditions will identify the obligations of the licensee in the environmental area, including, as appropriate, requirements for reporting and recordkeeping of environmental data and any conditions and monitoring requirements for the protection of the nonaquatic environment.
(d) The licensing basis for the renewed license includes the CLB, as defined in § 54.3(a); the inclusion in the licensing basis of matters such as licensee commitments does not change the legal status of those matters unless specifically so ordered pursuant to paragraphs (b) or (c) of this section.

§ 54.35 Requirements during term of renewed license.

During the term of a renewed license, licensees shall be subject to and shall continue to comply with all Commission regulations contained in 10 CFR Parts 2, 19, 20, 21, 26, 30, 40, 50, 51, 54, 55, 70, 72, 73, and 100, and the appendices to these parts that are applicable to holders of operating licenses.

§ 54.37 Additional records and recordkeeping requirements.

(a) The licensee shall retain in an auditable and retrievable form for the term of the renewed operating license all information and documentation required by, or otherwise necessary to document compliance with, the provisions of this part.
(b) After the renewed license is issued, the FSAR update required by 10 CFR 50.71(e) must include any systems, structures, and components newly identified that would have been subject to an aging management review or evaluation of time-limited aging analyses in accordance with § 54.21. This FSAR update must describe how the effects of aging will be managed such that the intended function(s) in § 54.4(b) will be effectively maintained during the period of extended operation.

§ 54.41 Violations.

(a) The Commission may obtain an injunction or other court order to prevent a violation of the provisions of the following acts--
    (1) The Atomic Energy Act of 1954, as amended.
    (2) Title II of the Energy Reorganization Act of 1974, as amended or
    (3) A regulation or order issued pursuant to those acts.
(b) The Commission may obtain a court order for the payment of a civil penalty imposed under Section 234 of the Atomic Energy Act--
    (1) For violations of the following--
        (i) Sections 53, 57, 62, 63, 81, 82, 101, 103, 104, 107, or 109 of the Atomic Energy Act of 1954, as amended;
        (ii) Section 206 of the Energy Reorganization Act;
        (iii) Any rule, regulation, or order issued pursuant to the sections specified in paragraph (b)(1)(i) of this section;
        (iv) Any term, condition, or limitation of any license issued under the sections specified in paragraph (b)(1)(i) of this section.
(2) For any violation for which a license may be revoked under Section 186 of the Atomic Energy Act of 1954, as amended.

Appendix C

USNRC Guidance Concerning Aging Effects & Aging Mechanisms

Table C-1: *Aging Effects* (Source: GALL Report - NUREG-1801)

Selected Definitions & Use of Terms for Describing and Standardizing Aging Effects	
Changes in dimensions	Changes in dimensions can result from void swelling.
Concrete cracking and spalling	Concrete cracking and spalling can result from freeze-thaw, aggressive chemical attack, and reaction with aggregates.
Crack growth	Increase in crack size, attributable to cyclic loading.
Cracking	This term is used in this document to be synonymous with the phrase "crack initiation and growth" in metallic substrates. Cracking in concrete can be caused by restraint shrinkage, creep, and aggressive environment.
Cracking, loss of bond, and loss of material (spalling, scaling)	Cracking, loss of bond, and loss of material (spalling, scaling) can be caused by corrosion of embedded steel in concrete.
Cracks; distortion; increase in component stress level	Within concrete structures, cracks, distortion, and increase in component stress level can be caused by settlement. Although settlement can be occur in a soil environment, the symptoms can be manifested in either an air-indoor uncontrolled or air-outdoor environment.
Cumulative fatigue damage	Cumulative fatigue damage is due to fatigue, as defined by ASME Boiler and Pressure Vessel Code.
Degradation of insulator quality	The decrease in insulating capacity can result from the presence of salt deposits or surface contamination. Although this derives from an aging mechanism (presence of salt deposits or surface contamination) that may be due to temporary, transient environmental conditions, the net result may be long lasting and cumulative.
Embrittlement, cracking, melting, discoloration, swelling, or loss of dielectric strength leading to reduced insulation resistance; electrical failure	Embrittlement, cracking, melting, discoloration, swelling, or loss of dielectric strength leading to reduced insulation resistance, electrical failure can result from mechanisms such as thermal or thermoxidative degradation of organics; radiation-induced oxidation, radiolysis and photolysis (UV sensitive materials only) of organics; moisture intrusion; and ohmic heating.
Expansion and cracking	Within concrete structures, expansion and cracking can result from reaction with aggregates.
Fatigue	Fatigue in copper fuse holder clamps can result from ohmic heating, thermal cycling, electrical transients, frequent manipulation, vibration, chemical contamination, corrosion, oxidation.
Fretting or lockup	Fretting is an aging effect due to accelerated deterioration at the interface between contacting surfaces as the result of corrosion and slight oscillatory movement between the two surfaces. In essence, both fretting and lockup are due to mechanical wear.
Hardening and loss of strength	Hardening and loss of strength can result from Eastover degradation of seals and other elastomeric components. Elastomers can experience increased hardness, shrinkage, and loss of strength, due to weathering.
Increase in porosity and permeability, cracking, loss of material (spalling, scaling), loss of strength	Concrete can increase in porosity and permeability, cracking, loss of material (spalling, scaling) due to aggressive chemical attack. In concrete, loss of material (spalling, scaling) and cracking can result from freeze-thaw processes. Loss of strength can result from leaching of calcium hydroxide in the concrete.
Increased resistance of connection	Increased resistance of connection in electrical transmission conductors and connections can be caused by oxidation or loss of preload.
Ligament cracking	Steel tube support plates can experience ligament cracking due to corrosion.
Localized damage and breakdown of insulation leading to electrical failure	Localized damage in polymeric electrical conductor insulation leading to electrical failure can be due to a number of aging mechanisms including moisture intrusion, and the formation of water trees. Based on operating experience, localized damage

Selected Definitions & Use of Terms for Describing and Standardizing Aging Effects	
	and breakdown of insulation may be exacerbated by manufacturing defects in the insulation of older electrical conductors, external damage, or damage due to poor installation practices.
Loosening of bolted connections	The loosening of bolted bus duct connections due to thermal cycling can result from ohmic heating.
Loss of fracture toughness	Loss of fracture toughness can result from various aging mechanisms including thermal aging, thermal aging embrittlement, and neutron irradiation embrittlement.
Loss of leak tightness	Steel airlocks can experience loss of leak tightness in closed position resulting from mechanical wear of locks, hinges, and closure mechanisms.
Loss of material	Loss of material may be due to general corrosion, boric acid corrosion, pitting corrosion, galvanic corrosion, crevice corrosion, erosion, fretting, flow-accelerated *corrosion, MIC, fouling, selective leaching, wastage, wear, and aggressive* chemical attack. In concrete structures, loss of material can also be caused by abrasion or cavitation or corrosion of embedded steel. For high voltage insulators, loss of material can be attributed to mechanical wear or wind-induced abrasion and fatigue due to wind blowing on transmission conductors.
Loss of material, loss of form	In earthen water-control structures, the loss of material and loss of form can result from erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, and seepage.
Loss of preload	Loss of preload due to gasket creep, thermal effects (including differential expansion and creep or stress relaxation), and self-loosening (which includes vibration, joint flexing, cyclic shear loads, thermal cycles) is an aging effect/mechanism accepted by industry as being within the scope of license renewal.
Loss of prestress	Loss of prestress in structural steel anchorage components can result from relaxation, shrinkage, creep, or elevated temperatures.
Reduction in foundation strength, cracking, differential settlement	Reduction in foundation strength, cracking, and differential settlement can result from erosion of porous concrete subfoundation.
Reduction of heat transfer	Reduction of heat transfer from fouling by the buildup, from whatever source, on the heat transfer surface. Although in heat exchangers, the tubes are the primary heat transfer component, heat exchanger internals including tubesheets and fins contribute to heat transfer and may be affected by the reduction of heat transfer due to fouling.
Reduction of strength and modulus	In concrete, reduction of strength and modulus can be attributed to elevated temperatures (>150°F general; >200°F local).
Reduction or loss of isolation function	Reduction or loss of isolation function in polymeric vibration isolation elements can result from elastomers exposed to radiation hardening, temperature, humidity, sustained vibratory loading.
Wall thinning	This is the term used to describe the specific type of loss of material due to flow-accelerated corrosion.

Table C-2: *Aging Mechanisms* (Source: GALL Report - NUREG-1801)

Selected Definitions & Use of Terms for Describing and Standardizing Aging Mechanisms	
Term	**Aging Mechanism Definition as used in the GALL Report**
Abrasion	As water migrates over a concrete surface, it may transport material that can abrade the concrete. The passage of water may also create a negative pressure at the water/air to concrete interface that can result in abrasion and cavitation degradation of the concrete. This may result in pitting or aggregate exposure due to loss of cement paste.
Aggressive chemical attack	Concrete, being highly alkaline (pH >12.5) is degraded by strong acids. Chlorides and sulfates of potassium, sodium, and magnesium may attack concrete, depending concentration in soil/ground water. Exposed surfaces of structures may be subject to sulfur-based acid-rain degradation. Minimum degradation thresholds are 500 ppm chlorides and 1500 ppm sulfates.
Boric acid corrosion	Corrosion by boric acid, which can occur where there is borated water leakage in an environment described as air with borated water leakage. See also Corrosion.
Cavitation	Formation and instantaneous collapse of innumerable tiny voids or cavities within a liquid subjected to rapid and intense pressure changes. Cavitation caused by severe turbulent flow can potentially lead to cavitation damage.
Chemical contamination	Degradation due to presence of chemical constituents.
Corrosion	Chemical or electrochemical reaction between a material, usually a metal, and its environment that produces a deterioration of the material and its properties.
Corrosion of embedded steel	If pH of the concrete in which steel is embedded is reduced (pH < 11.5) by intrusion of aggressive ions (e.g., chlorides > 500 ppm) in the presence of oxygen, embedded steel corrosion may occur. A reduction in pH may be caused by the leaching of alkaline products through cracks, entry of acidic materials, or carbonation. Chlorides may also be present in the constituents of the original concrete mix. The severity of the corrosion is affected by the properties and types of cement, aggregates, and moisture content.
Creep	Creep, for a metallic material, refers to a time-dependent continuous deformation process under constant stress. It is an elevated temperature process and is not a concern for low alloy steel below 700°F, for austenitic alloys below 1000°F, and for Ni-based alloys below 1800°F. Creep, in concrete, is related to the loss of absorbed water from the hydrated cement paste. It is a function of modulus of elasticity of the aggregate. It may result in loss of prestress in the tendons used in prestressed concrete containment.
Crevice Corrosion	Localized corrosion of a metal surface at, or immediately adjacent to, an area that is shielded from full exposure to the environment, because of close proximity between the metal and the surface of another material. Crevice corrosion occurs in a wetted or buried environment when a crevice or area of stagnant or low flow exists that allows a corrosive environment to develop in a component. It occurs most frequently in joints and connections, or points of contact between metals and non-metals, such as gasket surfaces, lap joints, and under bolt heads. Carbon steel, cast iron, low alloy steels, stainless steel, copper, and nickel base alloys are all susceptible to crevice corrosion. Steel can be subject to crevice corrosion in some cases after lining/cladding degradation.
Cyclic loading	One source of cyclic loading is due to periodic application of pressure loads and forces due to thermal movement of piping transmitted through penetrations and structures to which penetrations are connected. The typical result of cyclic loads on metal components is fatigue cracking and failure; however, the cyclic loads may also cause deformation that results in functional failure.
Deterioration of seals, gaskets, and moisture barriers (caulking, flashing, and other sealants)	Seals, gaskets, and moisture barriers (caulking, flashing, and other sealants) are subject to loss of sealing and leakage through containment caused by aging
Distortion	The aging mechanism of distortion can be caused by time dependent strain, or gradual elastic and plastic deformation of metal that is under constant stress at a value lower than its normal yield strength.
Elastomer degradation	Elastomer materials are substances whose elastic properties are similar to that of natural rubber. The term elastomer is sometimes used to technically distinguish synthetic rubbers and rubber-like plastics from natural rubber. Degradation may include cracking, crazing, fatigue breakdown, abrasion, chemical attacks, and weathering. [20, 21] Elastomer hardening refers to the degradation in elastic properties of the elastomer.

Selected Definitions & Use of Terms for Describing and Standardizing Aging Mechanisms	
Term	**Aging Mechanism Definition as used in the GALL Report**
Electrical transients	An electrical transient is a stressor caused by a voltage spike that can contribute to aging degradation. Certain types of high-energy electrical transients can contribute to electromechanical forces ultimately resulting in fatigue or loosening of bolted connections. Transient voltage surges are a major contributor to the early failure of sensitive electrical components
Elevated temperature	In concrete, reduction of strength and modulus can be attributed to elevated temperatures (>150°F general; >200°F local).
Erosion	Progressive loss of material from a solid surface due to mechanical interaction between that surface and a fluid, a multi-component fluid, or solid particles carried with the fluid.
Erosion settlement	Erosion (as defined above). Settlement of containment structure may occur during the design life due to changes in the site conditions, e.g., due to erosion or changes in the water table. The amount of settlement depends on the foundation material, and is generally determined by survey. Another term is erosion of the porous concrete sub-foundation.
Erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, seepage	In earthen water-control structures, the loss of material and loss of form can result from erosion, settlement, sedimentation, frost action, waves, currents, surface Run-off, and seepage.
Fatigue	A phenomenon leading to fracture under repeated or fluctuating stresses having a maximum value less than the tensile strength of the material. Fatigue fractures are progressive, and grow under the action of the fluctuating stress. Fatigue due to vibratory and cyclic thermal loads is defined as the structural degradation that can occur as a result of repeated stress/strain cycles caused by fluctuating loads, e.g., from vibratory loads, and temperatures, giving rise to thermal loads. After repeated cyclic loading of sufficient magnitude, micro-structural damage may accumulate, leading to macroscopic crack initiation at the most vulnerable regions. Subsequent mechanical or thermal cyclic loading may lead to growth of the initiated crack. Vibration may result in component cyclic fatigue, as well as in cutting, wear, and abrasion, if left unabated. Vibration is generally induced by external equipment operation. It may also result from flow resonance or movement of pumps or valves in fluid systems. Crack initiation and growth resistance is governed by factors including stress range, mean stress, loading frequency, surface condition, and the presence of deleterious chemical species.
Flow-accelerated corrosion (FAC)	Also termed erosion-corrosion. A co-joint activity involving corrosion and erosion in the presence of a moving corrosive fluid, leading to the accelerated loss of material.
Fouling	An accumulation of deposits. This term includes accumulation and growth of aquatic organisms on a submerged metal surface and also includes the accumulation of deposits, usually inorganic, on heat exchanger tubing. Biofouling, as a subset of fouling, can be caused by either macro-organisms (such as barnacles, Asian clams, zebra mussels, and others found in fresh and salt water) or micro-organisms, e.g., algae. Fouling can also be categorized as particulate fouling (sediment, silt, dust, and corrosion products), marine biofouling, or macrofouling, e.g., peeled coatings, debris, etc. Fouling in a raw water system can occur on the piping, valves, and heat exchangers. Fouling can result in a reduction of heat transfer, loss of material, or a reduction in the system flow rate (this last aging effect is considered active and thus is not in the purview of license renewal).
Freeze-Thaw, frost action	Repeated freezing and thawing is known to be capable of causing severe degradation to the concrete characterized by scaling, cracking, and spalling. The cause of this phenomenon is water freezing within the pores of the concrete, creating hydraulic pressure that, if unrelieved, will lead to freeze-thaw degradation. Factors that enhance the resistance of concrete to freeze-thaw degradation are a) adequate air content (e.g., within ranges specified in ACI 301-84), b) low permeability, c) protection until adequate strength has developed, and d) surface coating applied to frequently wet-dry surfaces.
Fretting	Aging effect due to accelerated deterioration at the interface between contacting surfaces as the result of corrosion, and slight oscillatory movement between the two surfaces.
Galvanic corrosion	Accelerated corrosion of a metal because of an electrical contact with a more noble metal or nonmetallic conductor in a corrosive electrolyte. Also called bimetallic corrosion, contact corrosion, dissimilar metal corrosion, or two-metal corrosion. Galvanic corrosion is an applicable aging mechanism for steel materials coupled to more noble metals in heat exchangers; galvanic corrosion of copper is of concern when coupled with the nobler stainless

Selected Definitions & Use of Terms for Describing and Standardizing Aging Mechanisms	
Term	**Aging Mechanism Definition as used in the GALL Report**
	steel.
General corrosion	Also known as uniform corrosion, corrosion proceeds at approximately the same rate over a metal surface. Loss of material due to general corrosion is an aging effect requiring management for low alloy steel, carbon steel, and cast iron in outdoor environments.
Intergranular stress corrosion cracking (IGSCC)	SCC in which the cracking occurs along grain boundaries.
Leaching of calcium hydroxide	Water passing through cracks, inadequately prepared construction joints, or areas that are not sufficiently consolidated during placing may dissolve some calcium containing products, of which calcium hydroxide is the most-readily soluble, in concrete. Once the calcium hydroxide has been leached away, other cementatious constituents become vulnerable to chemical decomposition, finally leaving only the silica and alumina gels behind with little strength. The water's aggressiveness in the leaching of calcium hydroxide depends on its salt content and temperature. This leaching action is effective only if the water passes through the concrete.
Mechanical loading	Applied loads of mechanical origins rather than from other sources, such as thermal.
Microbiologically influenced corrosion (MIC)	Any of the various forms of corrosion influenced by the presence and activities of such microorganisms as bacteria, fungi, and algae, and/or the products produced in their metabolism. Degradation of material that is accelerated due to conditions under a biofilm or microfouling tubercle, for example, anaerobic bacteria that can set up an electrochemical galvanic reaction or inactivate a passive protective film, or acid-producing bacterial that might produce corrosive metabolites.
Moisture intrusion	Influx of moisture through any viable process.
Ohmic heating	Ohmic heating is induced by current flow through a conductor and can be calculated using first principles of electricity and heat transfer. Ohmic heating is a thermal stressor and can be induced in situations, such as conductors passing through electrical penetrations. Ohmic heating is especially significant for power circuit penetrations.
Overload	Overload is one of the aging mechanisms that can cause loss of mechanical function in piping and components, such as constant and variable load spring hangers, guides, stops, sliding surfaces, design clearances, vibration isolators, fabricated from steel or other materials, such as Lubrite
Oxidation	Two types of reactions a) reaction in which there is an increase in valence resulting from a loss of electrons, or b) a corrosion reaction in which the corroded metal forms an oxide.
Photolysis	Chemical reactions induced or assisted by light.
Pitting corrosion	Localized corrosion of a metal surface, confined to a point or small area, which takes the form of cavities called pits.
Plastic deformation	Time-dependent strain, or gradual elastic and plastic deformation, of metal that is under constant stress at a value lower than its normal yield strength.
Presence of any salt deposits	The surface contamination resulting from the aggressive environment associated with the presence of any salt deposits can be an aging mechanism causing the aging effect of degradation of insulator quality. Although this aging mechanism may be due to temporary, transient environmental conditions, the net result may be long-lasting and cumulative for plants located in the vicinity of saltwater bodies.
Radiolysis	Chemical reactions induced or assisted by radiation. Radiolysis and photolysis aging mechanisms can occur in UV-sensitive organic materials.
Reaction with aggregate	The presence of reactive alkalis in concrete, can lead to subsequent reactions with aggregates that may be present. These alkalis are introduced mainly by cement, but also may come from admixtures, salt-contamination, seawater penetration, or solutions of deicing salts. These reactions include alkali-silica reactions, cement-aggregate reactions, and aggregate-carbonate reactions. These reactions may lead to expansion and cracking.
Restraint shrinkage	Restraint shrinkage can cause cracking in concrete transverse to the longitudinal construction joint.
Selective leaching	Also known as dealloying, e.g., dezincification or graphitic corrosion. Selective corrosion of one or more components of a solid solution alloy.
Settlement	Settlement of structures may occur during the design life due to changes in the site conditions, e.g., the water table. The amount of settlement depends on the foundation material and is

Selected Definitions & Use of Terms for Describing and Standardizing Aging Mechanisms	
Term	**Aging Mechanism Definition as used in the GALL Report**
	generally determined by survey.
Stress corrosion cracking (SCC)	Cracking of a metal produced by the combined action of corrosion and tensile stress (applied or residual).
Stress relaxation	Many of the bolts in reactor internals are stressed to a cold initial preload. When subject to high operating temperatures, over time, these bolts may loosen and the preload may be lost. Radiation can also cause stress relaxation, in highly stressed members such as bolts. Relaxation in structural steel anchorage components can be an aging mechanism contributing to the aging effect of loss of prestress.
Thermal aging embrittlement	Also termed thermal aging or thermal embrittlement. At operating temperatures of 500 to 650°F, cast austenitic stainless steels (CASS) exhibit a spinoidal decomposition of the ferrite phase into ferrite-rich and chromium-rich phases. This may give rise to significant embrittlement, i.e., reduction in fracture toughness, depending on the amount, morphology, and distribution of the ferrite phase and the composition of the steel. Thermal aging of materials other than CASS is a time- and temperature-dependent degradation mechanism that decreases material toughness. It includes temper embrittlement and strain aging embrittlement. Ferritic and low alloy steels are subject to both of these embrittlement, but wrought stainless steel is not affected by either of the processes.
Thermal effects, gasket creep, and self-loosening	Loss of preload due to gasket creep, thermal effects (including differential expansion and creep or stress relaxation), and self-loosening (which includes vibration, joint flexing, cyclic shear loads, thermal cycles) is within the scope of license renewal.
Thermal and mechanical loading	Loads (stress) due to mechanical or thermal (temperature) sources.
Thermal fatigue	Thermal (temperature) fatigue can result from phenomena such as thermal loading, thermal cycling, where there is cycling of the thermal loads and thermal stratification. Thermal stratification is a thermohydraulic condition with definitive hot and cold water boundary inducing thermal fatigue of the piping. Turbulent penetration is a thermo-hydraulic condition where hot and cold water mix as a result of turbulent flow conditions, leading to thermal fatigue of the piping.
Water trees	Water trees occur when the insulating materials are exposed to long-term, continuous electrical stress and moisture; these trees eventually result in breakdown of the dielectric and ultimate failure. The growth and propagation of water trees is somewhat unpredictable. Water treeing is a degradation and long-term failure phenomenon.
Wear	Wear is defined as the removal of surface layers due to relative motion between two surfaces or under the influence of hard abrasive particles. Wear occurs in parts that experience intermittent relative motion, frequent manipulation, or in clamped joints where relative motion is not intended but may occur due to a loss of the clamping force.
Weathering	Degradation of external surfaces of materials when exposed to outside environment.

Appendix D

Aging Management Program Example – Concrete Structures Monitoring

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XI.S2 ASME SECTION XI, SUBSECTION IWL

Program Description

10 CFR 50.55a imposes the examination requirements of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code, Section XI, Subsection IWL for reinforced and prestressed concrete containments (Class CC). The scope of IWL includes reinforced concrete and unbonded post-tensioning systems. This evaluation covers both the 1992 edition with the 2001 edition[1] including the 2002 and 2003 Addenda, as approved in 10 CFR 50.55a. ASME Code Section XI, Subsection IWL and the additional requirements specified in 10 CFR 50.55a(b)(2) constitute an existing mandated program applicable to managing aging of containment reinforced concrete and unbonded post-tensioning systems for license renewal.

The primary inspection method specified in IWL is visual examination (VT-3C, VT-1, VT-1C). For prestressed containments, tendon wires are tested for yield strength, ultimate tensile strength, and elongation. Tendon corrosion protection medium is analyzed for alkalinity, water content, and soluble ion concentrations. Prestressing forces are measured in selected sample tendons. IWL specifies acceptance criteria, corrective actions, and expansion of the inspection scope when degradation exceeding the acceptance criteria is found.

The evaluation of 10 CFR 50.55a and Subsection IWL as an aging management program (AMP) for license renewal is provided below.

Evaluation and Technical Basis

1. *Scope of Program:* Subsection IWL-1000 specifies the components of concrete containments within its scope. The components within the scope of Subsection IWL are reinforced concrete and unbonded post-tensioning systems of Class CC containments, as defined by CC-1000. Subsection IWL exempts from examination portions of the concrete containment that are inaccessible (e.g., concrete covered by liner, foundation material, or backfill, or obstructed by adjacent structures or other components).

   10 CFR 50.55a(b)(2)(viii) specifies additional requirements for inaccessible areas. It states that the licensee is to evaluate the acceptability of concrete in inaccessible areas when conditions exist in accessible areas that could indicate the presence of or result in degradation to such inaccessible areas. Steel liners for concrete containments and their integral attachments are not within the scope of Subsection IWL, but are included within the scope of Subsection IWE.

2. *Preventive Action:* No preventive actions are specified; Subsection IWL is a monitoring program. If a coating program is currently credited for managing the effects of aging of concrete surfaces, then the program is to be continued during the period of extended operation.

3. *Parameters Monitored or Inspected:* Table IWL-2500-1 specifies two categories for examination of concrete surfaces: Category L-A for all concrete surfaces and Category L-

[1] An applicant may rely on a different version of the ASME Code, but should justify such use. An applicant may wish to refer to the SOC for an update of 10 CFR § 50.55a to justify use of a more recent edition of the Code.

B for concrete surfaces surrounding tendon anchorages. Both of these categories rely on visual examination methods. Concrete surfaces are examined for evidence of damage or degradation, such as concrete cracks. IWL-2510 specifies that concrete surfaces are examined for conditions indicative of degradation, such as those defined in ACI 201.1R-77. Table IWL-2500-1 also specifies Category L-B for test and examination requirements for unbonded post tensioning systems. Tendon anchorage and wires or strands are visually examined for cracks, corrosion, and mechanical damage. Tendon wires or strands are also tested for yield strength, ultimate tensile strength, and elongation. Tendon corrosion protection medium is tested by analysis for alkalinity, water content, and soluble ion concentrations.

4. *Detection of Aging Effects:* The frequency and scope of examinations specified in 10 CFR 50.55a and Subsection IWL ensure that aging effects would be detected before they would compromise the design-basis requirements. The frequency of inspection is specified in IWL-2400. Concrete inspections are performed in accordance with Examination Category L-A. Under Subsection IWL, inservice inspections for concrete and unbonded post-tensioning systems are required at one, three, and five years following the structural integrity test. Thereafter, inspections are performed at five-year intervals. For sites with two plants, the schedule for inservice inspection is provided in IWL-2421. In the case of tendons, only a sample of the tendons of each tendon type requires examination at each inspection. The tendons to be examined during an inspection are selected on a random basis. Table IWL-2521-1 specifies the number of tendons to be selected for each type (e.g., hoop, vertical, dome, helical, and inverted U) for each inspection period. The minimum number of each tendon type selected for inspection varies from 2 to 4%. Regarding detection methods for aging effects, all concrete surfaces receive a visual VT-3C examination. Selected areas, such as those that indicate suspect conditions and areas surrounding tendon anchorages, receive a more rigorous VT-1 or VT-1C examination. Prestressing forces in sample tendons are measured. In addition, one sample tendon of each type is detensioned. A single wire or strand is removed from each detensioned tendon for examination and testing. These visual examination methods and testing would identify the aging effects of accessible concrete components and prestressing systems in concrete containments.

5. *Monitoring and Trending:* Except in inaccessible areas, all concrete surfaces are monitored on a regular basis by virtue of the examination requirements. For prestressed containments, trending of prestressing forces in tendons is required in accordance with paragraph (b)(2)(viii) of 10 CFR 50.55a. In addition to the random sampling used for tendon examination, one tendon of each type is selected from the first-year inspection sample and designated as a common tendon. Each common tendon is then examined during each inspection. This procedure provides monitoring and trending information over the life of the plant. 10 CFR 50.55a and Subsection IWL also require that prestressing forces in all inspection sample tendons be measured by lift-off tests and compared with acceptance standards based on the predicted force for that type of tendon over its life.

6. *Acceptance Criteria:* IWL-3000 provides acceptance criteria for concrete containments. For concrete surfaces, the acceptance criteria rely on the determination of the "Responsible Engineer" (as defined by the ASME Code) regarding whether there is any evidence of damage or degradation sufficient to warrant further evaluation or repair. The acceptance criteria are qualitative; guidance is provided in IWL-2510, which references ACI 201.1R-77 for identification of concrete degradation. IWL-2320 requires that the Responsible Engineer be a registered professional engineer experienced in evaluating

the inservice condition of structural concrete and knowledgeable of the design and construction codes and other criteria used in design and construction of concrete containments. Quantitative acceptance criteria based on the "Evaluation Criteria" provided in Chapter 5 of ACI 349.3R may also be used to augment the qualitative assessment of the responsible engineer. The acceptance standards for the unbonded post-tensioning system are quantitative in nature. For the post-tensioning system, quantitative acceptance criteria are given for tendon force and elongation, tendon wire or strand samples, and corrosion protection medium. 10 CFR 50.55a and Subsection IWL do not define the method for calculating predicted tendon prestressing forces for comparison to the measured tendon lift-off forces. The predicted tendon forces are to be calculated in accordance with Regulatory Guide 1.35.1, which provides an acceptable methodology for use through the period of extended operation.

7. *Corrective Actions:* Subsection IWL specifies that items for which examination results do not meet the acceptance standards are to be evaluated in accordance with IWL-3300 "Evaluation" and described in an engineering evaluation report. The report is to include an evaluation of whether the concrete containment is acceptable without repair of the item and if repair is required, the extent, method, and completion date of the repair or replacement. The report also identifies the cause of the condition and the extent, nature, and frequency of additional examinations. Subsection IWL also provides repair procedures to follow in IWL-4000. This includes requirements for the concrete repair, repair of reinforcing steel, and repair of the post-tensioning system. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

8. *Confirmation Process:* When areas of degradation are identified, an evaluation is performed to determine whether repair or replacement is necessary. As part of this evaluation, IWL-3300 specifies that the engineering evaluation report include the extent, nature, and frequency of additional examinations. IWL-4000 specifies the requirements for examination of areas that are repaired. Pressure tests following repair or modifications are in accordance with IWL-5000. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.

9. *Administrative Controls:* IWA-1400 specifies the preparation of plans, schedules, and inservice inspection summary reports. In addition, written examination instructions and procedures, verification of qualification level of personnel who perform the examinations, and documentation of a quality assurance program are specified. IWA-6000 specifically covers the preparation, submittal, and retention of records and reports. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

10. *Operating Experience:* ASME Section XI, Subsection IWL was incorporated into 10 CFR 50.55a in 1996. Prior to this time, operating experience pertaining to degradation of reinforced concrete and prestressing systems in concrete containments was gained through the inspections required by 10 CFR Part 50, Appendix J and ad hoc inspections conducted by licensees and the Nuclear Regulatory Commission (NRC). Recently, NRC Information Notice (IN) 99-10 described occurrences of degradation in prestressing systems. The program is to consider the degradation concerns described in this generic communication. Implementation of Subsection IWL, in accordance with 10 CFR 50.55a, is

a necessary element of aging management for concrete containments through the period of extended operation.

References

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10 CFR 50.55a, Codes and Standards, Office of the Federal Register, National Archives and Records Administration, 2005.

ACI Standard 201.1R-77, *Guide for Making a Condition Survey of Concrete in Service*, American Concrete Institute.

ACI Standard 349.3R-96, *Evaluation of Existing Nuclear Safety-Related Concrete Structures*, American Concrete Institute.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components*, Subsection IWA, *General Requirements*, 2001 edition including the 2002 and 2003 Addenda, The ASME Boiler and Pressure Vessel Code, The American Society of Mechanical Engineers, New York, NY.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components*, Subsection IWE, *Requirements for Class MC and Metallic Liners of Class CC Components of Light-Water Cooled Power Plants*, 2001 edition including the 2002 and 2003 Addenda, The ASME Boiler and Pressure Vessel Code, The American Society of Mechanical Engineers, New York, NY.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components*, Subsection IWL, *Requirements for Class CC Concrete Components of Light-Water Cooled Power Plants*, 2001 edition including the 2002 and 2003 Addenda, The ASME Boiler and Pressure Vessel Code, The American Society of Mechanical Engineers, New York, NY.

NRC Information Notice 99-10, Revision 1, *Degradation of Prestressing Tendon Systems in Prestressed Concrete Containment*, U.S. Nuclear Regulatory Commission, October 7, 1999.

Appendix E

License Renewal Inspection Policy and Guidance*

USNRC Inspection Manual Chapter (MC) 2516 – Policy and Guidance for the License Renewal Inspection Programs (Edited)

2516-01 PURPOSE

The purpose of MC 2516 is to document policy and guidance for review and inspection activities associated with the License Renewal Inspection Program (LRIP). The LRIP is the process used by Nuclear Regulatory Commission (NRC) staff, region, and consultants to verify the accuracy of the aging management programs and activities associated with an applicant's request for a renewed license for a commercial nuclear power plant beyond the initial licensing period under Title 10 of the Code of Federal Regulation, (10 CFR) Part 54.

2516-02 POLICY AND OBJECTIVES

02.01 The basic policies, excerpted from the Statements of Consideration of the License Renewal Rule, and objectives used in the development and implementation of the LRIP are as follows:

a. The NRC exists to assure that the public health and safety, the common defense and security, and the environment are protected.
b. With respect to license renewal of a commercial nuclear power plant, the NRC has established the following two basic principles:
   1. The first principle of license renewal is that with the exception of age-related degradation and possibly a few other issues related to safety only during extended operation of nuclear power plants, the existing regulatory process is adequate to ensure that the licensing bases of all currently operating plants provide and maintain an acceptable level of safety so that operation will not be inimical to public health and safety or common defense and security.
   2. The second and equally important principle of license renewal holds that the plant-specific licensing basis must be maintained during the renewal term in the same manner and to the same extent as during the original licensing term. This would be accomplished, in part, through a program of age-related degradation management.
c. An applicant for license renewal should rely on the plant's current licensing basis (CLB), actual plant-specific experience, industry-wide operating experience, as appropriate, and existing engineering evaluations to determine those systems, structures, and components that are the initial focus of the license renewal review.
d. The detrimental effects of aging affecting passive structures and components are less apparent than the detrimental effects of aging affecting structures and components that perform their intended functions with moving parts or a change in configuration or properties (active structures and components). Therefore, the aging management review of passive structures and components is needed to provide reasonable assurance that their intended functions are maintained consistent with the CLB during the period of extended operation.
e. For the purpose of license renewal, an applicant can generically exclude, from its integrated plant assessment, the aging management review of the following: 1) active structures and components, and 2) structures and components that are replaced, based on qualified life or specified time period, when the replacement frequency is less than 40 years ("short-lived"). In addition, some components are both active and passive. Components that are passive, or both active and passive, must be included within the scope of components requiring an aging management review based on the intended function(s) that is performed without moving parts or change in configuration or properties.

* Note: A copy of the related USNRC License Renewal Inspection Procedure 71002 is provided in Attachment D of the CGI Report 06-22, *Condition Monitoring of Passive Systems, Structures, and Components*

f. Postulated failures that could result from system interdependencies that are not part of the CLB and that have not been previously experienced need not be considered as part of a license renewal application (LRA). However, for some license renewal applicants, postulated failures that are part of the CLB may require consideration of more than the first level support systems.

02.02 The objectives of the LRIP are as follows:

a. The LRIP will provide the guidance for the inspection of license renewal programs, documentation, and activities necessary for the staff to make a finding that an applicant's LRA, aging management programs (AMPs), implementation activities, and on-site documentation provide reasonable assurance that the effects of aging will be effectively managed consistent with the CLB during the period of extended operation.

b. The LRIP will also provide the guidance for assessing the adequacy of implemented AMPs to effectively manage the effects of aging, consistent with the licensee's CLB, after the renewed license is issued.

2516-03 DEFINITIONS

Current licensing basis is the set of NRC requirements applicable to a specific plant and a licensee's written regulatory commitments for ensuring compliance with and operation within applicable NRC requirements and the plant-specific design basis (including all modifications and additions to such commitments over the life of the license) that are docketed and in effect. The CLB includes the NRC regulations contained in 10 CFR Parts 2, 19, 20, 21, 26, 30, 40, 50, 51, 54, 55, 70, 72, 73, 100 and appendices thereto; orders; license conditions; exemptions; and technical specifications. It also includes the plant-specific design-basis information defined in 10 CFR 50.2 as documented in the most recent final safety analysis report (FSAR) as required by 10 CFR 50.71; and the licensee's commitments remaining in effect that were made in docketed licensing correspondence such as licensee responses to NRC bulletins, generic letters, and enforcement actions, as well as licensee commitments documented in NRC safety evaluations or licensee event reports.

Regulatory Commitment is an explicit statement made by a licensee (or applicant) to take a specific action agreed to or volunteered by a licensee, and that has been submitted in writing on the docket to the Commission.

Integrated Plant Assessment (IPA) is a licensee assessment that demonstrates that a nuclear power plant facility's structures and components requiring aging management review in accordance with §54.21(a) for license renewal have been identified and that the effects of aging on the functionality of such structures and components will be managed to maintain the CLB such that there is an acceptable level of safety during the period of extended operation.

Nuclear power plant means a nuclear power facility of a type described in 10 CFR 50.21(b) or 50.22.

2516-06 LICENSE RENEWAL INSPECTION PROGRAM

06.01 Purpose.

The fundamental task of the LRIP is to ensure that there is reasonable assurance that the effects of aging will be managed consistent with the CLB during the period of extended operation. The program objectives derived from that task are as follows:

a. To provide a basis for recommending issuance or denial of a renewed license.

b. To identify weaknesses within an applicant's overall license renewal program or an individual AMP that fail to provide reasonable assurance that the applicable aging effects will be adequately managed during the period of extended operation.

c. To determine the status of compliance with 10 CFR Part 54 and other areas relating to maintaining and operating the plant such that the continued operation beyond the current licensing term will not be inimical to the public health and safety.

06.02 Independent Inspection Policy.

These inspections should be conducted in accordance with inspection procedure IP 71002. However, it is not possible to anticipate all the unique circumstances that might be encountered during the course of a particular inspection and, therefore, individual inspectors are expected to exercise initiative in conducting inspections based on their expertise and experience to assure that all the inspection objectives are met. If in the course of conducting an inspection, current potential safety concerns or compliance issues outside the scope of the procedure being executed are identified, the concerns should be pursued to the extent necessary to understand the issue and then they will be turned over to the Senior Resident Inspector for further follow-up inspection.

06.03 License Renewal Review Program.

The license renewal review program consists of an LRA review and site inspections. The LRA review is primarily a headquarters review performed by NRR to ensure that the applicant meets the technical and regulatory requirements of the rule, and to verify that the format and content of the application meet the requirements of the rule. The regional staff and inspection team members will become familiar with the LRA in preparation for inspections to provide operational and performance input in the application review, to assess the applicant's commitments against their past performance and experience, and in preparation to provide a regional recommendation to grant or deny approval for the applicant's request for a renewed license.

06.04 Site-Inspections.

The site inspections are assessments of an applicant's implementation of and compliance with 10 CFR Part 54 requirements. All inspection teams will be led by the regions and any NRR supporting staff will be detailed to the region for the period of time necessary to prepare, inspect, and document inspection activities. The site inspections will be performed by a team inspection in the areas of the scoping and screening activities, observation of the condition of plant equipment, and implementation of the aging management programs and review of associated documentation. By observing the current condition of plant equipment in the scope of license renewal, inspectors may identify the effects of aging not previously recognized. Such observations allow the inspectors to evaluate the success of previously implemented plant programs, which are being credited for license renewal AMPs. The site-inspection activities will be performed using IP 71002 "License Renewal Inspections."

06.05 Post Renewal Site-Inspections.

Site inspections of AMP implementation conducted after the approval of the renewed license will be conducted in accordance with IP 71003 "Post-Approval Site Inspection for License Renewal." These inspections will verify the licensee's continued compliance with 10 CFR Part 50 and implementation of commitments related to the LRA.

06.06 Inspection Documentation.

Inspections will be documented with inspection reports sent to the applicant and made publicly available in ADAMS. Attachments to IMC 2516 provide guidance on the preparation of documents related to the site inspection. Attachment 1, "Region Notification of Plant Readiness For License Renewal," provides a region with guidance on how to prepare its overall evaluation of inspection activities performed on an applicant for license renewal. Attachment 2, "Sample License Renewal Inspection Letter," is a sample letter of an overall evaluation of the inspection completion. The results of site team inspections will provide major input for the staff and regional recommendations to grant or deny an applicant's request for a renewed license.

Appendix F

Nuclear Related Aging Management and Life Extension Abbreviations and Acronyms

Abbreviation or Acronym	Description
AMP	Aging Management Program
AMR	Aging Management Review
ANSI	American Nuclear Standards Institute
ASME	American Society of Mechanical Engineers
BAW	Babcock and Wilcox
BIR	Benefit to Investment Ratio
BOP	Balance of Plant
BWROG	Boiling Water Reactor Owners Group
CBA	Cost Benefit Analysis
CDF	Core Damage Frequency
CFR	Code of Federal Regulations
CLB	Current Licensing Basis
CUF	Cumulative Usage Factor
DBD	Design Basis Document
DOE	U.S. Department of Energy
EPIX	Equipment Performance and Information Exchange
EPRI	Electrical Power Research Institute
EQ	Environmental Qualification
ER	Environmental Report
FHA	Fire Hazards Analysis and Fire Protection Program
FSAR	Final Safety Analysis Report
FSD	Functional System Description
GALL	Generic Aging Lessons Learned
IOE	Industry Operating Experience
INPO	Institute of Nuclear Power Operations
ISG	Interim Staff Guidance
ISI	In-Service Inspection
LCM	Life Cycle Management
LRA	License Renewal Application
LRR	License Renewal Rule
MIC	Microbiological Influenced Corrosion
MPFF	Maintenance Preventable Functional Failure
MR	Maintenance Rule
NEI	Nuclear Energy Institute
NMAC	Nuclear Maintenance Assist Center
NPAR	Nuclear Plant Aging Reports
NPV	Net Present Value
NRC	Nuclear Regulatory Commission (also USNRC)
O&M	Operation and Maintenance
OEM	Original Equipment Manufacturer
PdM	Predictive (diagnostic) Maintenance

Abbreviation or Acronym	Description
PM	Preventive Maintenance
PRA	Probabilistic Risk Analysis
RAI	Request for Additional Information (NRC Questions)
RAW	Risk Achievement Worth
RMPFF	Repetitive MPFF
RRW	Risk Reduction Worth
SER	Safety Evaluation Report
SOC	Statement of Considerations
SPV	Single Point Vulnerability
SRP	Standard Review Plan
SRP-LR	Standard Review Plan for License Renewal
SSC	Systems, Structures and Components
TLAA	Time Limited Aging Analyses
USNRC	United States Nuclear Regulatory Commission
WANO	World Association of Nuclear Operators

Appendix G

Bibliography of Selected Nuclear Aging Management and Life Extension Reports

Regulatory Requirements

- The License Renewal Rule, Title 10 of the United States Code of Federal Regulations, Part 54 (10 CFR Part 54), "Requirements for Renewal of Operating Licenses for Nuclear Power Plants"
- The Maintenance Rule, Title 10 of the United States Code of Federal Regulations, Part 50.65 (10 CFR 54.65), "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants"

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- NUREG/CR-5314, "Life Assessment Procedures for Major LWR Components," Vol. 3, "Cast Stainless Steel Components"
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- NUREG/CR-5419, "Aging Assessment of Instrument Air Systems in Nuclear Power Plants," January 1990
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- NUREG/CR-5546, "An Investigation of the Effects of Thermal Aging on the Fire Damageability of Electrical Cables"
- NUREG/CR-5779, "Aging of Non-Power-Cycle Heat Exchangers Used in Nuclear Power Plants," Vol. 1, April 1992
- NUREG/CR-6052, "Methodology for Reliability Based Condition Assessment-Application to Concrete Structures in Nuclear Plants"
- NUREG/CR-6679, "Assessment of Age-Related Degradation of Structures and Passive Components for U.S. Nuclear Power Plants"
- NUREG-1568, "License Renewal Demonstration Program: NRC Observations and Lessons Learned." December 1996
- NUREG-1611, "Aging Management of Nuclear Power Plant Containments for License Renewal." September 1997
- NUREG-1800 "Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants" (SRP-LR)
- NUREG-1801, "Generic Aging Lessons Learned (GALL) Report"
- ORNL/NRC/LTR-91/25, "Throttled Valve Cavitation and Erosion"
- PNL-5722, "Operating Experience and Aging Assessment of ECCS Pump Room Coolers"
- PNL-SA-18407, "Understanding and Managing Corrosion in Nuclear Power Plants"
- Regulatory Guide 1.188, "Standard Format and Content for Applications to Renew Nuclear Power Plant Operating Licenses."
- SECY-01-0074, "Approval to Publish Generic License Renewal Guidance Documents," dated April 26, 2001

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- B&W Owners Group, "Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools", BAW-2270, Revision 2, 1999, EPRI Report No. TR-114882, April 2000
- B&W Owners Group, "Aging Effects for Structures and Structural Components (Structural Tools)", BAW-2279, December 1997
- BWR Owners Group License Renewal Committee, "Aging Management Review of the BWR Reference Plant Primary Containment for License Renewal", BWROG-12-15980, Revision 0, March 1996

* EPRI reports are available from the Electric Power Research Institute, Inc., Publications Department, 3420 Hillview Avenue, Palo Alto, California 94304

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- EPRI TR-103842, "Class I Structures License Renewal Industry Report," July 1994
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- EPRI, "Generic Communications Database", Version 3.0, Release 5.0, July 2002
- EPRI, "System Monitoring Database", (SysMon), Version 1.3, 1998.
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- Nuclear Electric Insurance Limited (NEIL), Loss Control Standards, September 2002

From: Beth Sienel
To: Jonathan Rowley
Date: 02/20/2008 9:03:30 AM
Subject: Re: Update to CHECWORKS

Jonathan,

I talked to the FAC program owner (Jim Fitzpatrick) and he said the update is in progress. More details: The Fleet has upgraded to the new version of Checworks and VY put EPU conditions into the program. They are now in the process of verifying.

Hope this helps,
Beth

>>> Jonathan Rowley 2/19/2008 4:16 PM >>>
Beth

I (and OGC) need to find out if VY has updated the CHECWORKS computer program they used to predict and track pipe thinning to account for power uprate conditions. VY stated during the EPU process that the FAC Program (using CHECWORKS) would be updated to account for uprated power conditions. There has been one outage since the EPU was granted during which the updating was to have initiated, that is my understanding.

Could you contact the Flow-Accelerated Corrosion Program owner and verify if they have started updating the program?

CC: Raymond Powell; Ricardo Fernandes

Mail Envelope Properties (47BC3325.EC4 : 5 : 55534)

Subject: Re: Update to CHECWORKS
Creation Date 02/20/2008 9:03:17 AM
From: Beth Sienel

Created By: BEK@nrc.gov

Recipients
nrc.gov
TWGWPO03.HQGWDO01
JGR (Jonathan Rowley)

nrc.gov
kp1_po.KP_DO
RAF1 CC (Ricardo Fernandes)
RJP CC (Raymond Powell)

Post Office	**Route**
TWGWPO03.HQGWDO01	nrc.gov
kp1_po.KP_DO	nrc.gov

Files	**Size**	**Date & Time**
MESSAGE	1528	02/20/2008 9:03:17 AM

Options
Expiration Date: None
Priority: Standard
ReplyRequested: No
Return Notification: None

Concealed Subject: No
Security: Standard

Junk Mail Handling Evaluation Results
Message is not eligible for Junk Mail handling
Message is from an internal sender

Junk Mail settings when this message was delivered
Junk Mail handling disabled by User
Junk Mail handling disabled by Administrator
Junk List is not enabled
Junk Mail using personal address books is not enabled
Block List is not enabled

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Dr. Brian W. Sheron
Associate Director for Project Licensing and Technical Analysis
U.S. Nuclear Regulatory Commission
MS 05E7
11555 Rockville Pike
Rockville, MD 20852-2738

Dear Dr. Sharon:

Enclosed are the results of a project given to my Penn State Graduate Students on finding pipe failure data over a range of pipe sizes and conditions. We specifically looked for stainless steel data as well as carbon steel pipe data. Since the data is from several sources other than nuclear the pipe wall thickness may not always be comparable to reactor pipe wall thicknesses. In some of the reports the students did separate the failure and leakage data by mechanism such that we could then screen the data.

I had the students normalize the data in such a fashion that we could then compare to the break frequency spectrum curves generated by the NRC experts group. I did talk to Rob Tenoning on the best way of normalizing our data such that we would be consistent with the break frequency plots. The key findings from the students work is that the data, when plotted in the same manner as the break frequency spectrum plots from the NRC experts work, shows a much flatter behavior at the larger pipe sizes indicating a more similar probability level for failure as compared to a more significant decrease in the failure probability as given by the NRC break frequency spectrum.

I am complying all the independent sets of data in a spread sheet and will attempt a further screening. Once complete, I will send you a copy of the data. I wanted you to have these report now with all the data so you could make an independent assessment.

Please let me know if you need anything else.

Very truly yours,

L.E. Hochreiter
Professor of Nuclear and Mechanical Engineering

NucE 597D - Project 1

DATA COLLECTION OF PIPE FAILURES OCCURING IN STAINLESS STEEL AND CARBON STEEL PIPING

Pennsylvania State University
Dr. L.E. Hochreiter
April 2005

Executive Summary

Currently the Nuclear Regulatory Commission (NRC) is contemplating changing the acceptance criteria for Emergency Core Cooling Systems (ECCS) for light-water nuclear power reactors contained in NRC Regulation 10 CFR 50.46. This regulation sets specific numerical acceptance criteria for peak cladding temperature, clad oxidation, total hydrogen generation, and core cooling under loss-of-coolant accident (LOCA) situations. Furthermore, the regulation requires that a spectrum of break sizes and locations be analyzed to determine the most severe case and to ensure the plant design can meet the acceptance criteria under such conditions.

Currently the regulation states that breaks of pipes in the reactor coolant pressure boundary up to, and including, a break equivalent in size to the double-ended rupture of the largest pipe in the reactor coolant system must be considered. While this restricts the design, it maintains a large safety margin ensuring the plant is covered under all LOCA situations. However, an impetus for change has resulted from materials research, analysis, and experience that indicate that the catastrophic rupture of a limiting size pipe at a nuclear power plant is a very low probability event.

If approved, the proposed change would divide the break spectrum into two categories based upon the likelihood of a break. Breaks of higher likelihood, breaks smaller than 10 inches, would need to meet the current requirements set forth in 10 CFR 50.46. Breaks of a lower likelihood, those larger than 10 inches, would only need to meet the requirements of maintaining a coolable geometry and having the capability for long term cooling.

The purpose of this project was to collect data on instances of pipe failures including cracks, leaks, and ruptures. For each instance of failure the plant type, pipe diameter, type of pipe, failure mechanism, and type of failure was recorded. The data was then collapsed based on plant type (PWR or BWR), type of pipe (carbon or stainless steel), pipe size, and failure mechanism. Then, normalized failure frequencies were calculated as a function of both pipe size and failure mechanism per reactor year. Plots of the frequency distributions were generated on a semi-log scale, and the frequency distributions as a function of pipe size were compared to the NRC predicted failure frequencies.

For this project our group collected two, independent sets of data. The first set was provided by the OECD Pipe Failure Data Exchange Project (OPDE), with a total of 2891 data points. The second set consists of 67 data points collected by our group from various sources. The two sets of data were not combined due to the lack of information accompanying the data presented in the OPDE database, such as plant name or exact failure size. This made it impossible to identify overlapping coverage and combine the information. Rather, within this report we have analyzed each data set individually in order to make an overall comparison of the trends observed for each data set and the NRC predictions.

The results from both the OPDE and the independent sets of data detailed in this report do not support the NRC's assertion that larger sized pipes do not break frequently enough to be used as design criteria. The overall trends of both sets of data show that the frequency of failures does not decrease as sharply with increasing pipe size as the NRC predicts.

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1.0 Detailed Introduction of Problem

In order to ensure the safety of nuclear plants the cooling performance of the Emergency Core Cooling System (ECCS) must be calculated in accordance with an acceptable evaluation model, and must be calculated for a number of postulated loss-of-coolant accidents (LOCA) resulting from pipe breaks of different sizes, locations, and other properties. This is done to provide sufficient assurance that a plant can handle even the most severe postulated LOCA. LOCA's are hypothetical accidents that would result from the loss of reactor coolant, at a rate in excess of the capability of the reactor coolant makeup system. Currently, the evaluation criteria for these types of accidents state that pipe breaks in the reactor coolant pressure boundary up to and including a break equivalent in size to the double-ended rupture of the largest pipe in the reactor coolant system must be considered. In the case of such an event the NRC has set forth the following criteria that must be met for a design to be considered acceptable [37]:

a. Peak cladding temperature must not exceed 2200° F.

b. Maximum cladding oxidation must not exceed 0.17 times the total cladding thickness before oxidation.

c. Maximum hydrogen generation. The calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam shall not exceed 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react.

d. A coolable geometry of the core must be maintained.

e. After any calculated successful initial operation of the ECCS, the calculated core temperature shall be maintained at an acceptably low value and decay heat shall be removed for the extended period of time required by the long-lived radioactivity remaining in the core.

While requiring that all plants be analyzed in the case of a double-ended guillotine break of the largest pipe restricts the design, it does maintain a large safety margin ensuring the plant is covered in all pipe break situations. However, an impetus for change has resulted from materials research, analysis, and experience which indicate that the catastrophic rupture of a large pipe at a nuclear power plant is a very low probability event. The hypothesis that is currently being set forth is that small pipes break more frequently than large pipes. The criteria would change so that the NRC would refocus their analysis efforts because they want to make sure that the appropriate amount of time and money are being invested in the areas of most concern.

Furthermore, risk analyses indicate that large break LOCA's are not significant contributors to plant risk. According to a presentation given by Dr. Brian Sheron of the NRC at Penn State in the Fall 2004, "using the double ended break of the largest pipe in the reactor coolant system as the design basis for the plant results in ECCS equipment requirements which are inconsistent with risk insights and places an unwarranted emphasis and resource expenditure on low risk contributors. This also places constraints on operations which are unnecessary from a public health and safety perspective." Therefore, the proposed rule change would use the pipe size with the largest break frequency as the design basis for pipe rupture and accident analysis of the plant. A pipe size with a 10 inch diameter is currently being suggested. [37]

The proposed change would divide the break spectrum into two categories based upon the likelihood of a break. Breaks of higher likelihood, or those smaller than 10 inches, would need to meet the current requirements set forth in 10 CFR 50.46. These include criteria (a) through (e) above. On the other hand, breaks of a lower likelihood, or those larger than 10 inches up to and including a double-ended guillotine break of the largest pipe in the reactor coolant system, would only need to meet the requirements of maintaining a coolable geometry and having the capability for long term cooling. Thus, criteria (a), (b), and (c) would be eliminated for these cases. [37]

The purpose of this project was to collect data on instances of pipe breaks, leaks, and cracking. These failures included pipe failures from broken pipes either by splits, ruptures, or guillotines, and cracks in pipes, either circumferential or length wise. For each instance found the plant type, pipe diameter, type of pipe, failure mechanism, and type of failure was recorded. Only stainless steel and carbon steel pipes were considered. Then, normalized failure frequency distributions were developed and compared to NRC predictions.

The predicted NRC failure frequencies were taken from Table 3 on page 14 of 10 CFR 50.46, LOCA Frequency Development [38]. This table is replicated below.

Table 1-1. NRC Total Preliminary BWR and PWR Frequencies.

Plant Type	Effective Break Size (inches)	Current Day Estimates (per cal. yr)			
		5%	Median	Mean	95%
BWR	1/2	3.0E-05	2.2E-04	4.7E-04	1.7E-03
	1 7/8	2.2E-06	4.3E-05	1.3E-04	5.0E-04
	3 1/4	2.7E-07	5.7E-06	2.4E-05	9.4E-05
	7	6.6E-08	1.4E-06	6.0E-06	2.3E-05
	18	1.5E-08	1.1E-07	2.2E-06	6.3E-06
	41	3.5E-11	8.5E-10	2.3E-06	8.6E-09
PWR	1/2	7.3E-04	3.7E-03	6.3E-03	2.0E-02
	1 7/8	6.9E-06	9.9E-05	2.3E-04	8.5E-04
	3 1/4	1.6E-07	4.9E-06	1.6E-05	6.2E-05
	7	1.1E-08	6.3E-07	2.3E-06	8.8E-06
	18	5.7E-10	7.5E-09	3.9E-08	1.5E-07
	41	4.2E-11	1.4E-09	2.3E-08	7.0E-08

2.0 Data Collected

For this project our group collected two, independent sets of data. The first set was provided by the OECD Pipe Failure Data Exchange Project (OPDE), with a total of 2891 data points. The second set consists of 67 data points collected by our group from various sources listed as references in this report. The two sets of data were not combined due to the lack of information accompanying the data presented in the OPDE database, such as plant name and exact failure size, which made identifying overlapping coverage impossible. Rather, within this report each data set was individually analyzed in order to make an overall comparison of the trends observed for each data set and the NRC predictions.

OECD Pipe Failure Data Exchange Project [3]

OECD Pipe Failure Data Exchange Project (OPDE) was established in 2002 as an international forum for the exchange of pipe failure information. It is a 3-year project with participants from twelve countries, including Belgium, Canada, Czech Republic, Finland, France, Germany, Japan, Republic of Korea, Spain, Sweden, Switzerland and the United States. "The objective of OPDE is to establish a well structured, comprehensive database on pipe failure events and to make the database available to project member organizations that provide data." [3] The OPDE database evolved from what existed in the "SLAP database" at the end of 1998 [2].

OPDE covers piping in primary-side and secondary-side process systems, standby safety systems, auxiliary systems, containment systems, support systems and fire protection systems. Furthermore, ASME Code Class 1 through 3 and non-Code piping has been considered. At the end of 2003, the OPDE database included approximately 4,400 records on pipe failure. The database also includes an additional 450 records on water hammer events where the structural integrity of piping was challenged but did not fail.

Access to the actual OPDE database is restricted to organizations providing input data. However, a "OPDE-Light" version of the database will be made available later this year to non-member organizations contracted by a project member to perform work or which pipe failure data is needed. This version will not include proprietary data, such as the exact pipe diameter, where failure occurred, and preclude any plant identities or dates. Our group was fortunate enough to get a copy of this "light" version of the database for BWR and PWR pipe failures reported as of February 24, 2005. A total of 2891 failures (1536 for PWR plants and 1355 for BWR plants) were provided in this database, and considered for this project.

The database listed the plant type, reactor system, apparent cause of failure, pipe size group, number of total failures for each cause and pipe size group, and then a break down of the type of failure within the category. An excerpt from the OPDE-Light database has been provided for clarification in Table 2-1 on the following page. The database, in its entirety, has been included in Appendix A of this report.

However, there are a few problems with this database related to the purpose of this project. First, since the database did not provide the type of pipe (carbon or stainless) for each failure, a reasonable prediction of what type of pipe was involved in the failure based on the plant system, which was given, was made. The type of pipe assumed for each system is also given in the following page in Table 2-2.

Additionally, as previously mentioned, no explicit pipe diameters were given for each failure due to the proprietary nature of this information. Rather, the failures were collected into group sizes before it was sent out. A total of six group sizes were utilized by OPDE. The range of pipe diameters that comprise each group is given in Table 2-3. The main problem with these groupings, and the database in general, is that pipes larger than 10 inches in diameter are all grouped together and there is no way of determining how much larger than 10 inches they actually were. Finally, for the purpose of this analysis any crack, leak, or issue (i.e. wall thinning) with the pipe was considered to be a failure. However, the OPDE database lists the information by type of failure. The definitions of each failure type have been included in Table 2-4.

Independently Collected Data [5-36]

For the purpose of this project our group collected separate information on instances of piping failures and their causes. The information was collected primarily from Nuclear Regulatory Commission (NRC) bulletins, information notices, event reports, and generic letters. Our group was able to compile a total of 67 instances of piping failures. This database is provided in Appendix B. While our database is much smaller than the one compiled by the OECD Pipe Failure Exchange Project, it provides an independent check of the trends observed by that database.

A list of references is provided at the end of this report, and some of the actual references, printed from the NRC website, have been included in Appendix D.

Table 2-3. Definition of OPDE Pipe Size Groups.

Pipe Size Group	Corresponding Pipe Diameters (mm)	Corresponding Pipe Diameters (inches)
1	DN < 15	DN < 0.6
2	15 < DN < 25	0.6 < DN < 1.0
3	25 < DN < 50	1.0 < DN < 2.0
4	50 < DN < 100	2.0 < DN < 4.0
5	100 < DN < 250	4.0 < DN < 10.0
6	DN > 250	DN > 10.0

Table 2-4. OPDE Pipe Failure Definitions.

Type	Description
Crack - Part	Part through-wall crack (≥ 10% of wall thickness)
Crack - Full	Through-wall but no active leakage; leakage may be detected given a plant mode change involving cooldown and depressurization.
Wall Thinning	Internal pipe wall thinning due to flow accelerated corrosion - FAC
Small Leak	Leak rate within Technical Specification limits
Pinhole Leak	Differs from "small leak" only in terms of the geometry of the throughwall defect and the underlying degradation or damage mechanism
Large Leak	Leak rate in excess of Technical Specification limits but within the makeup capability of safety injection systems
Severance	Full circumferential crack – caused by external impact/force, including high-cycle mechanical fatigue – limited to small-diameter piping, typically
Rupture	Large flow rate and major, sudden loss of structural integrity. Invariably caused by influences of a degradation mechanism (e.g., FAC) in combination with a severe overload condition (e.g., water hammer)

4.3 Pipe Failures as a function of Failure Mechanism

This section of the report summarizes the frequency of failure mechanisms for carbon and stainless steel pipes. The information presented in figures 4.3-1 through 4.3-3 represents the normalized failure frequencies for each failure mechanism. This data is also presented in tabular form in table 4.3-1. The data was collapsed by pipe sizes and broken apart by steel type and plant type. The data was normalized for each type of steel based on the number of reactor years and the total amount of failures (carbon +stainless) for each plant.

Table 4.3-1. Failure Frequencies of Pipes for each Failure Mechanism.

Plant Type	Failure Mechanism	Carbon Steel Failure Frequency	Stainless Steel Failure Frequency	Total Failure Frequency
PWR	Corrosion	2.04E-05	5.38E-06	2.57E-05
PWR	FAC	2.29E-05	2.32E-05	4.61E-05
PWR	MIC	8.26E-06	1.92E-07	8.45E-06
PWR	Erosion	1.84E-05	2.30E-06	2.07E-05
PWR	Fatigue	1.77E-05	9.62E-05	1.14E-04
PWR	Human Factors	6.91E-06	2.42E-05	3.11E-05
PWR	Mechanical Failures	4.23E-06	7.11E-06	1.13E-05
PWR	SCC	9.60E-07	3.25E-05	3.34E-05
PWR	Water Hammer	0.00E+00	3.84E-07	3.84E-07
PWR	Misc	1.15E-06	2.69E-06	3.84E-06
BWR	Corrosion	6.31E-06	6.97E-06	1.33E-05
BWR	FAC	1.26E-05	1.37E-05	2.63E-05
BWR	MIC	1.31E-06	2.18E-07	1.52E-06
BWR	Erosion	8.71E-06	1.96E-06	1.07E-05
BWR	Fatigue	1.55E-05	4.90E-05	6.44E-05
BWR	Human Factors	5.22E-06	1.85E-05	2.37E-05
BWR	Mechanical Failures	3.92E-06	5.44E-06	9.36E-06
BWR	SCC	4.14E-06	1.36E-04	1.40E-04
BWR	Water Hammer	4.35E-07	2.18E-07	6.53E-07
BWR	Misc	8.71E-07	4.14E-06	5.01E-06

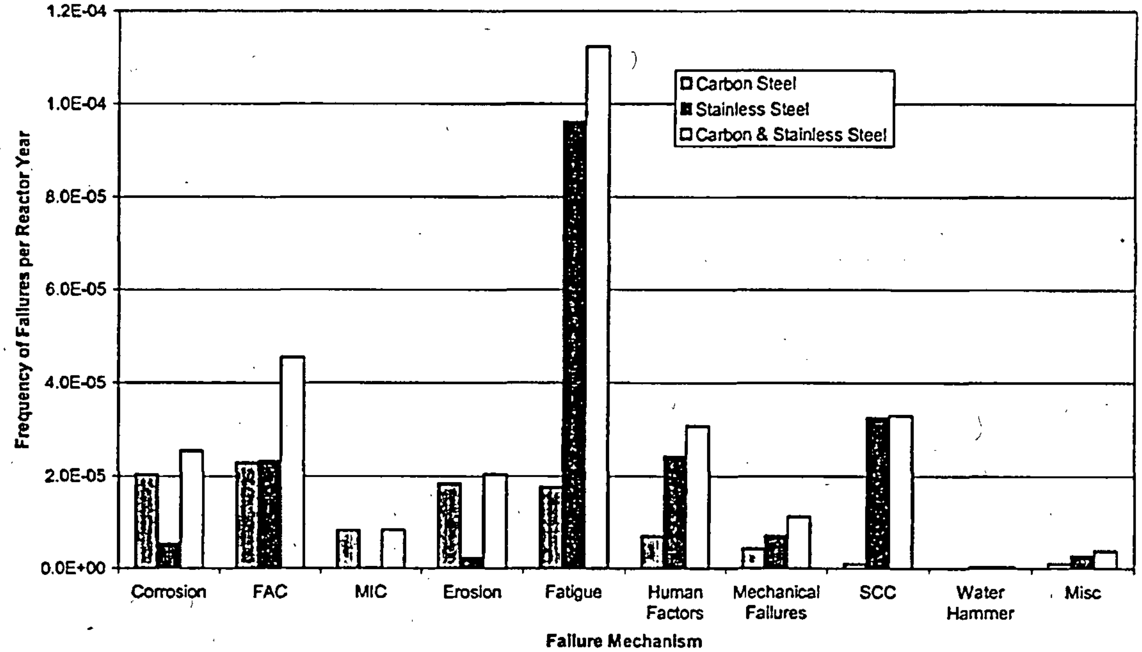

Figure 4.3-1. PWR Failure Frequency for Carbon and Stainless Steel Pipes as a Function of Failure Mechanism

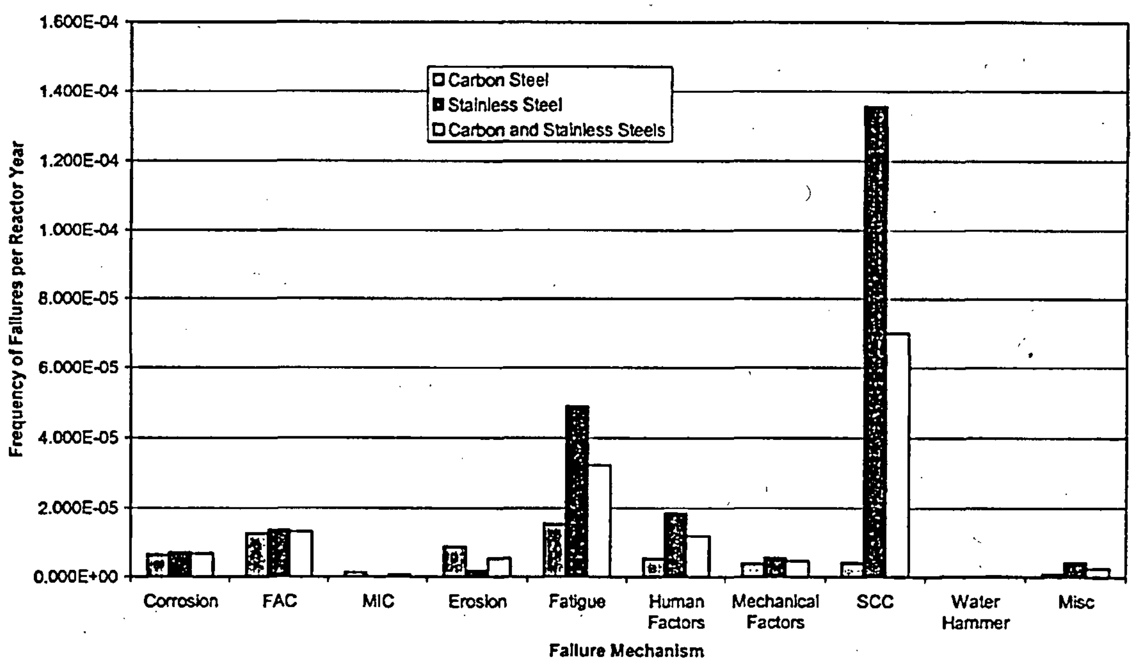

Figure 4.3-2. BWR Failure Frequency for Carbon and Stainless Steel Pipes as a Function of Failure Mechanism

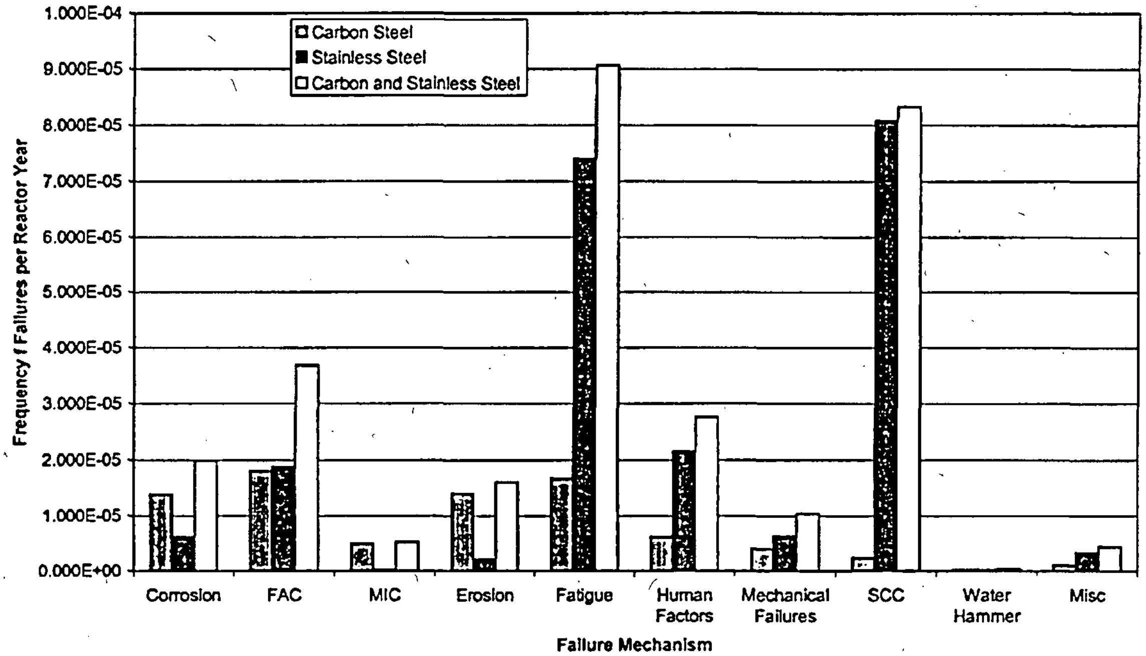

Figure 4.3-3. PWR and BWR Failure Frequency for Carbon and Stainless Steel Pipes as a Function of Failure Mechanism

From these plots it was determined that PWR plants are dominated by fatigue failures and BWR plants are dominated by stress corrosion cracking failures. However, in general the most frequent failure mechanisms for both plants are corrosion, fatigue, mechanical factors, and stress corrosion cracking. These four failure mechanisms were analyzed as a function of pipe size in figures 4.3-4 through 4.4-7.

For these plots corrosion includes general corrosion, flow accelerated corrosion, and microbiological corrosion. Stress corrosion cracking was not included with corrosion because the pipe failure method for stress corrosion cracking is different than the other corrosion types. Though mechanical failure frequency was not the highest, mechanical failures were chosen because they appear to be independent of pipe type and plant type. Human factors were ignored because they are a factor of quality assurance as opposed to the other failure mechanisms which are primarily a factor of operation. In regards to human factors it is not known if they have decreased with reactor operating experience because the dates of failures was not included with the OPDE data.

PWR	SS	FWC	Corrosion	3	3							1		2	
PWR	SS	FWC	Corrosion	4	1					1					
PWR	SS	FWC	Corrosion	6	3		1				1			1	
PWR	SS	FWC	Corrosion-fatigue	4	1		1								
PWR	SS	FWC	Corrosion-fatigue	6	3		2							1	
PWR	SS	FWC	Erosion	2	2									2	
PWR	SS	FWC	Erosion	5	1									1	
PWR	SS	FWC	FAC - Flow Accelerated Corrosion	1	2						1			1	
PWR	SS	FWC	FAC - Flow Accelerated Corrosion	2	4					1	1	1		1	
PWR	SS	FWC	FAC - Flow Accelerated Corrosion	3	7				1		3	1		2	
PWR	SS	FWC	FAC - Flow Accelerated Corrosion	4	11		1			1	2	3		2	2
PWR	SS	FWC	FAC - Flow Accelerated Corrosion	5	27				1	2	1	11		4	8
PWR	SS	FWC	FAC - Flow Accelerated Corrosion	6	67				1	1		7		8	50
PWR	SS	FWC	Fatigue	2	3								1	2	
PWR	SS	FWC	Fatigue	3	1									1	
PWR	SS	FWC	Fatigue	4	1									1	
PWR	SS	FWC	Galvanic Corrosion	3	2					2					
PWR	SS	FWC	HF.CONSTANST	2	2					1				1	
PWR	SS	FWC	HF.CONSTANST	4	2									2	
PWR	SS	FWC	HF CONSTANST	6	1										1
PWR	SS	FWC	HF.Design error	1	1									1	
PWR	SS	FWC	HF.Fabrication Error	4	1										1
PWR	SS	FWC	HF:REPAIR/MAINT	4	1						1				
PWR	SS	FWC	HF:REPAIR/MAINT	6	1									1	
PWR	SS	FWC	HF.Welding Error	1	1									1	
PWR	SS	FWC	HF.Welding Error	2	2						2				
PWR	SS	FWC	HF.Welding error	3	2						1			1	
PWR	SS	FWC	HF.Welding error	5	1									1	
PWR	SS	FWC	HF.Welding Error	6	3		1				1			1	
PWR	SS	FWC	Severe overloading	2	5		1							4	
PWR	SS	FWC	Severe overloading	3	1							1			
PWR	SS	FWC	Severe overloading	4	2			1						1	
PWR	SS	FWC	Severe overloading	5	2		1					1			
PWR	SS	FWC	Severe overloading	6	6		1					4		1	
PWR	SS	FWC	Thermal Fatigue	2	2							1		1	
PWR	SS	FWC	Thermal Fatigue	3	2							1		1	
PWR	SS	FWC	Thermal Fatigue	6	13		9			1				3	
PWR	SS	FWC	Thermal Fatigue - Cycling	6	1									1	
PWR	SS	FWC	Thermal Fatigue - Stratification	6	5		5								
PWR	SS	FWC	Vibration-fatigue	1	5							3		2	
PWR	SS	FWC	Vibration-Fatigue	2	23					1		2	2	18	
PWR	SS	FWC	Vibration-fatigue	3	5	1						3		1	
PWR	SS	FWC	Vibration-Fatigue	4	2					1				1	
PWR	SS	FWC	Vibration-Fatigue	5	4	1	1							2	
PWR	SS	FWC	Vibration-fatigue	6	5		4							1	
PWR	SS	FWC	Water Hammer	5	1							1			
PWR	SS	FWC	Water Hammer	6	1					1					
PWR	CS	IA-SA	Fatigue	2	1								1		
PWR	CS	IA-SA	HF.Human error	1	2							1	1		
PWR	CS	IA-SA	HF Human error	2	2								2		
PWR	CS	IA-SA	Severe overloading	2	1									1	
PWR	CS	IA-SA	Severe overloading	3	1								1		
PWR	CS	IA-SA	Vibration-fatigue	1	4							1	2	1	
PWR	CS	IA-SA	Vibration-fatigue	2	11							6	4	2	
PWR	CS	PCS	Corrosion	2	1									1	
PWR	CS	PCS	Erosion	5	2									2	
PWR	CS	PCS	Erosion	6	1		1								
PWR	CS	PCS	FAC - Flow Accelerated Corrosion	2	4							1		3	
PWR	CS	PCS	FAC - Flow Accelerated Corrosion	3	7							2		5	
PWR	CS	PCS	FAC - Flow Accelerated Corrosion	4	9					1		4		3	1
PWR	CS	PCS	FAC - Flow Accelerated Corrosion	5	28					3		6		20	
PWR	CS	PCS	FAC - Flow Accelerated Corrosion	6	12					2		3		7	
PWR	CS	PCS	Fatigue	5	1									1	
PWR	CS	PCS	Fretting	3	1									1	
PWR	CS	PCS	HF:Welding error	5	1					1					
PWR	CS	PCS	PWSCC	4	1									1	
PWR	CS	PCS	Severe overloading	2	1							1			

PWR	CS	PCS	Severe overloading	6	2							2			
PWR	CS	PCS	Thermal fatigue	3	1									1	
PWR	CS	PCS	Vibration-Fatigue	1	2								1	1	
PWR	CS	PCS	Vibration-fatigue	2	10								1	9	
PWR	CS	PCS	Vibration-fatigue	3	1									1	
PWR	CS	PCS	Vibration-fatigue	6	4									4	
PWR	SS	RAS	B/A-SCC	2	2						1			1	
PWR	SS	RAS	B/A-SCC	3	5		1							4	
PWR	SS	RAS	Brittle-Fracture	1	1				1						
PWR	SS	RAS	Cavitation-erosion	6	1									1	
PWR	SS	RAS	Corrosion	1	1									1	
PWR	SS	RAS	Corrosion	2	2						1			1	
PWR	SS	RAS	Corrosion	4	5					1	3			1	
PWR	SS	RAS	Corrosion	5	2						1			1	
PWR	SS	RAS	ECSCC - External Chloride Induced SCC	1	6						4			2	
PWR	SS	RAS	ECSCC - External Chloride Induced SCC	2	1									1	
PWR	SS	RAS	ECSCC - External Chloride Induced SCC	3	1									1	
PWR	SS	RAS	ECSCC - External Chloride Induced SCC	4	2									2	
PWR	SS	RAS	Erosion-cavitation	4	2									2	
PWR	SS	RAS	Excessive Vibration	3	1									1	
PWR	SS	RAS	FAC - Flow Accelerated Corrosion	2	1									1	
PWR	SS	RAS	FAC - Flow Accelerated Corrosion	3	1									1	
PWR	SS	RAS	Fretting	1	1									1	
PWR	SS	RAS	Fretting	3	1									1	
PWR	SS	RAS	HF.CONST/INST	1	3				1		1			1	
PWR	SS	RAS	HF:CONST/INST	2	6				1					5	
PWR	SS	RAS	HF.CONST/INST	3	5						1			4	
PWR	SS	RAS	HF:CONST/INST	4	3									3	
PWR	SS	RAS	HF.Fabrication Error	2	1									1	
PWR	SS	RAS	HF:Human error	2	1									1	
PWR	SS	RAS	HF:Human error	3	1						1				
PWR	SS	RAS	HF.REPAIR/MAINT	1	1									1	
PWR	SS	RAS	HF.Welding Error	1	4						1			3	
PWR	SS	RAS	HF.Welding Error	2	7					1	2			4	
PWR	SS	RAS	HF.Welding Error	3	4	2					1			1	
PWR	SS	RAS	HF.Welding error	4	2						1			1	
PWR	SS	RAS	IGSCC - Intergranular SCC	4	1					1					
PWR	SS	RAS	MIC - Microbiologically Induced Corrosion	2	1									1	
PWR	SS	RAS	Overpressurization	5	1							1			
PWR	SS	RAS	PWSCC	2	2					1				1	
PWR	SS	RAS	PWSCC	3	7						1			6	
PWR	SS	RAS	PWSCC	4	5					1				4	
PWR	SS	RAS	PWSCC	5	3						1			2	
PWR	SS	RAS	Severe overloading	2	1									1	
PWR	SS	RAS	Severe overloading	3	3		3								
PWR	SS	RAS	TGSCC - Transgranular SCC	1	5									5	
PWR	SS	RAS	TGSCC - Transgranular SCC	2	1	1									
PWR	SS	RAS	TGSCC - Transgranular SCC	3	3						1			2	
PWR	SS	RAS	TGSCC - Transgranular SCC	4	1									1	
PWR	SS	RAS	Thermal Fatigue	3	5				1	1				3	
PWR	SS	RAS	Thermal Fatigue	4	2				1					1	
PWR	SS	RAS	Thermal Fatigue - Cycling	3	1		1								
PWR	SS	RAS	Unreported	4	1									1	
PWR	SS	RAS	Unreported	5	1						1				
PWR	SS	RAS	Vibration-fatigue	1	10		1					1		8	
PWR	SS	RAS	Vibration-fatigue	2	105		2		7	3	12	2	3	76	
PWR	SS	RAS	Vibration-fatigue	3	44	1	2		2	7	7			25	
PWR	SS	RAS	Vibration-fatigue	4	10				1		2			7	
PWR	SS	RAS	Vibration-fatigue	5	4		1							3	
PWR	SS	RAS	Vibration-fatigue	6	1									1	
PWR	SS	RCPB	B/A-SCC	1	1									1	
PWR	SS	RCPB	B/A-SCC	2	1									1	
PWR	SS	RCPB	Corrosion	2	2		1			1					
PWR	SS	RCPB	Corrosion-fatigue	2	1				1						
PWR	SS	RCPB	Corrosion-fatigue	4	1							1			
PWR	SS	RCPB	ECSCC - External Chloride Induced SCC	1	1	1									
PWR	SS	RCPB	Fretting	1	1		1								

PWR	SS	RCPB	HF.CONST/INST	1	5				2					3	
PWR	SS	RCPB	HF.CONST/INST	2	12	4			1					7	
PWR	SS	RCPB	HF.CONST/INST	3	2									2	
PWR	SS	RCPB	HF CONST/INST	4	1									1	
PWR	SS	RCPB	HF.CONST/INST	5	1									1	
PWR	SS	RCPB	HF.Design Error	1	1									1	
PWR	SS	RCPB	HF:Design error	2	1							1			
PWR	SS	RCPB	HF:REPAIR/MAINT	1	1							1			
PWR	SS	RCPB	HF Welding Error	1	3						2			1	
PWR	SS	RCPB	HF.Welding Error	2	11					1			1	9	
PWR	SS	RCPB	HF.Welding Error	3	2									2	
PWR	SS	RCPB	HF.Welding error	6	1		1								
PWR	SS	RCPB	Hydrogen embrittlement	1	1				1						
PWR	SS	RCPB	IGSCC - Intergranular SCC	5	1		1								
PWR	SS	RCPB	PWSCC	1	2						1			1	
PWR	SS	RCPB	PWSCC	2	44	26	2			1	4		1	10	
PWR	SS	RCPB	PWSCC	3	6		1							5	
PWR	SS	RCPB	PWSCC	4	3		1							2	
PWR	SS	RCPB	PWSCC	5	2		1							1	
PWR	SS	RCPB	PWSCC	6	7		2				2			3	
PWR	SS	RCPB	Severe overloading	2	3									3	
PWR	SS	RCPB	Severe overloading	3	1							1			
PWR	SS	RCPB	TGSCC - Transgranular SCC	1	7	1	1				1			4	
PWR	SS	RCPB	TGSCC - Transgranular SCC	2	5						1			4	
PWR	SS	RCPB	TGSCC - Transgranular SCC	5	1					1					
PWR	SS	RCPB	Thermal fatigue	1	4									4	
PWR	SS	RCPB	Thermal fatigue	2	1									1	
PWR	SS	RCPB	Thermal fatigue	3	4		1			1	1			1	
PWR	SS	RCPB	Thermal fatigue	6	1		1								
PWR	SS	RCPB	Thermal Fatigue - Cycling	3	1									1	
PWR	SS	RCPB	Thermal Fatigue - Cycling	6	1		1								
PWR	SS	RCPB	Vibration-Fatigue	1	31				1	5			1	24	
PWR	SS	RCPB	Vibration-Fatigue	2	82	2			3	10	1			66	
PWR	SS	RCPB	Vibration-fatigue	3	11					4				7	
PWR	SS	RCPB	Vibration-fatigue	4	2					1				1	
PWR	SS	RCPB	Vibration-Fatigue	6	2									2	
PWR	SS	RCS-INSTR	Fatigue	1	1									1	
PWR	SS	RCS-INSTR	HF.CONST/INST	1	1					1					
PWR	SS	RCS-INSTR	HF:CONST/INST	2	1				1						
PWR	SS	RCS-INSTR	Vibration-Fatigue	1	1									1	
PWR	SS	RCS-INSTR	Vibration-fatigue	2	1									1	
PWR	CS	SG	Corrosion	1	1									1	
PWR	CS	SG	Deformation/Thermal Fatigue	2	1									1	
PWR	CS	SG	FAC - Flow Accelerated Corrosion	3	3							1		2	
PWR	CS	SG	HF.Welding Error	6	1						1				
PWR	CS	SG	PWSCC	1	3	3									
PWR	CS	SG	TGSCC - Transgranular SCC	2	1									1	
PWR	CS	SG	Vibration-Fatigue	2	2									2	
PWR	CS	SG	Vibration-fatigue	4	1									1	
PWR	SS	SIR	B/A-SCC	3	1									1	
PWR	SS	SIR	B/A-SCC	5	3		1							2	
PWR	SS	SIR	Cavitation-erosion	3	1							1			
PWR	SS	SIR	Cavitation-erosion	5	2									2	
PWR	SS	SIR	Corrosion	2	1									1	
PWR	SS	SIR	ECSCC - External Chloride Induced SCC	5	3		2				1				
PWR	SS	SIR	ECSCC - External Chloride Induced SCC	6	1						1				
PWR	SS	SIR	Erosion-cavitation	2	3						1			2	
PWR	SS	SIR	FAC - Flow Accelerated Corrosion	2	1						1				
PWR	SS	SIR	Freezing	1	1	1									
PWR	SS	SIR	Fretting	6	1										1
PWR	SS	SIR	HF.CONST/INST	1	1									1	
PWR	SS	SIR	HF:CONST/INST	2	4						1			3	
PWR	SS	SIR	HF.CONST/INST	5	2					1				1	
PWR	SS	SIR	HF Human error	2	1									1	
PWR	SS	SIR	HF.REPAIR/MAINT	6	1									1	
PWR	SS	SIR	HF.Welding Error	1	3						2			1	
PWR	SS	SIR	HF.Welding error	2	7					1	1	1		4	

PWR	SS	SIR	HF.Welding Error	3	1									1	
PWR	SS	SIR	HF.Welding Error	4	2						1			1	
PWR	SS	SIR	HF.Welding Error	5	2	1	1								
PWR	SS	SIR	HF.Welding Error	6	1		1								
PWR	SS	SIR	Overstressed	1	3									3	
PWR	SS	SIR	PWSCC	2	1						1				
PWR	SS	SIR	PWSCC	3	5									5	
PWR	SS	SIR	PWSCC	4	2		2								
PWR	SS	SIR	PWSCC	5	17		2			2	3			10	
PWR	SS	SIR	Severe Overloading	1	1									1	
PWR	SS	SIR	Severe overloading	2	3							2		1	
PWR	SS	SIR	Severe overloading	5	2		1							1	
PWR	SS	SIR	Severe overloading	6	2		1	1							
PWR	SS	SIR	TGSCC - Transgranular SCC	1	1	1									
PWR	SS	SIR	TGSCC - Transgranular SCC	2	1									1	
PWR	SS	SIR	TGSCC - Transgranular SCC	4	1						1				
PWR	SS	SIR	TGSCC - Transgranular SCC	5	1		1								
PWR	SS	SIR	Thermal fatigue	3	1		1								
PWR	SS	SIR	Thermal fatigue	4	3		2		1						
PWR	SS	SIR	Thermal fatigue	5	8		2		2	4					
PWR	SS	SIR	Thermal Fatigue - Cycling	3	1		1								
PWR	SS	SIR	Thermal Fatigue - Cycling	4	1									1	
PWR	SS	SIR	Unreported	3	2									2	
PWR	SS	SIR	Unreported	5	1		1								
PWR	SS	SIR	Unreported	6	1						1				
PWR	SS	SIR	Vibration-fatigue	0	3					1		1		1	
PWR	SS	SIR	Vibration-fatigue	1	8							2		6	
PWR	SS	SIR	Vibration-fatigue	2	42		2		1	3	3	2		31	
PWR	SS	SIR	Vibration-fatigue	3	9		1						1	7	
PWR	SS	SIR	Vibration-fatigue	4	3									3	
PWR	SS	SIR	Vibration-fatigue	5	7	1	1			1				4	
PWR	CS	STEAM	Corrosion	3	1					1					
PWR	CS	STEAM	Corrosion-fatigue	6	1									1	
PWR	CS	STEAM	Erosion	4	1									1	
PWR	CS	STEAM	Erosion	5	1						1				
PWR	CS	STEAM	FAC - Flow Accelerated Corrosion	2	10							1		9	
PWR	CS	STEAM	FAC - Flow Accelerated Corrosion	3	9									9	
PWR	CS	STEAM	FAC - Flow Accelerated Corrosion	4	8					1	1	1		5	
PWR	CS	STEAM	FAC - Flow Accelerated Corrosion	5	14					1		3		9	1
PWR	CS	STEAM	FAC - Flow Accelerated Corrosion	6	14					1		1		10	2
PWR	CS	STEAM	Fretting	3	1						1				
PWR	CS	STEAM	HF.CONST/INST	2	3							1		2	
PWR	CS	STEAM	HF.Human Error	2	1							1			
PWR	CS	STEAM	HF Human error	6	1									1	
PWR	CS	STEAM	HF.Welding Error		1						1				
PWR	CS	STEAM	HF.Welding Error	3	1						1				
PWR	CS	STEAM	HF.Welding error	6	2		2								
PWR	CS	STEAM	Overstressed	1	1					1					
PWR	CS	STEAM	Severe overloading	4	1									1	
PWR	CS	STEAM	Severe overloading	5	2							2			
PWR	CS	STEAM	Severe overloading	6	3		2					1			
PWR	CS	STEAM	Vibration-fatigue	1	2							1		1	
PWR	CS	STEAM	Vibration-fatigue	2	9		1					1	1	6	
PWR	CS	STEAM	Vibration-fatigue	3	2							1		1	
PWR	CS	STEAM	Vibration-fatigue	4	1									1	
PWR	CS	STEAM	Vibration-fatigue	6	1									1	

PLANT TYPE	PIPE TYPE	SYSTEM GROUP	APPARENT CAUSE	PIPE SIZE GROUP	TOTAL NO. OF RECORDS	Crack-Full	Crack-Part	Deformation	Large Leak	Leak	P/H-Leak	Rupture	Severance	Small Leak	Wall thinning
BWR	CS	AUXC	Corrosion	1	1				1						
BWR	CS	AUXC	Corrosion	2	4						1			3	
BWR	CS	AUXC	Corrosion	3	2					1				1	
BWR	CS	AUXC	Corrosion	4	3					1	1			1	
BWR	CS	AUXC	Corrosion	5	4					1	1			1	1
BWR	CS	AUXC	Corrosion	6	7				2		2			2	1
BWR	CS	AUXC	Erosion-cavitation	3	1						1				
BWR	CS	AUXC	Erosion-cavitation	6	1						1				
BWR	CS	AUXC	Erosion-corrosion	3	4						2			2	
BWR	CS	AUXC	Erosion-corrosion	4	7				1	2	1			3	
BWR	CS	AUXC	Erosion-corrosion	5	9						3			5	1
BWR	CS	AUXC	Erosion-corrosion	6	15					2	8			2	3
BWR	CS	AUXC	HF.CONST/INST	2	1									1	
BWR	CS	AUXC	HF:CONST/INST	5	1						1				
BWR	CS	AUXC	HF:Fabrication Error	5	1		1								
BWR	CS	AUXC	MIC - Microbiologically Induced Corrosion	2	1					1					
BWR	CS	AUXC	MIC - Microbiologically Induced Corrosion	4	2						2				
BWR	CS	AUXC	MIC - Microbiologically Induced Corrosion	5	1						1				
BWR	CS	AUXC	MIC - Microbiologically Induced Corrosion	6	1									1	
BWR	CS	AUXC	Severe overloading	3	3									3	
BWR	CS	AUXC	Severe overloading	5	2							1		1	
BWR	CS	AUXC	Severe overloading	6	2								2		
BWR	CS	AUXC	Unreported	6	1									1	
BWR	CS	AUXC	Vibration-fatigue	2	11					1			2	8	
BWR	CS	AUXC	Vibration-Fatigue	3	1									1	
BWR	CS	AUXC	Vibration-Fatigue	4	1									1	
BWR	CS	AUXC	Vibration-Fatigue	5	1	1									
BWR	SS	Containment System	Brittle fracture	6	1		1								
BWR	SS	Containment System	Corrosion	2	1									1	
BWR	SS	Containment System	HF.CONST/INST	5	1		1								
BWR	SS	Containment System	IGSCC - Intergranular SCC	5	1		1								
BWR	SS	Containment System	Severe overloading	5	1								1		
BWR	SS	Containment System	Severe overloading	6	2	1								1	
BWR	SS	Containment System	Vibration-Fatigue	1	1								1		
BWR	SS	CS	Fatigue	1	1							1			
BWR	SS	CS	HF.Welding Error	0	1										1
BWR	SS	CS	IGSCC - Intergranular SCC	4	1						1				
BWR	SS	CS	TGSCC - Transgranular SCC	5	1									1	
BWR	CS	EHC		2	1					1					
BWR	CS	EHC	Fretting	1	2					1	1				
BWR	CS	EHC	HF:CONST/INST	1	1									1	
BWR	CS	EHC	HF:Human error	1	1									1	
BWR	CS	EHC	HF.Human error	4	1									1	
BWR	CS	EHC	HF.Welding Error	2	1							1			
BWR	CS	EHC	Vibration-Fatigue	1	3							3			
BWR	CS	EHC	Vibration-fatigue	2	7				1	2		2		2	
BWR	CS	EHC	Vibration-fatigue	3	1									1	
BWR	SS	EPS	Fatigue	1	1								1		
BWR	SS	EPS	Vibration-fatigue	1	7							1	2	4	
BWR	SS	EPS	Vibration-fatigue	2	2									2	
BWR	CS	FPS	Corrosion	1	1						1				
BWR	CS	FPS	Corrosion	4	1						1				
BWR	CS	FPS	Corrosion	5	2					1	1				
BWR	CS	FPS	FAC - Flow Accelerated Corrosion	4	1						1				
BWR	CS	FPS	Fretting	5	1									1	
BWR	CS	FPS	HF.CONST/INST	5	1								1		
BWR	CS	FPS	HF.Human error	3	1							1			
BWR	CS	FPS	HF:Human Error	6	1				1						
BWR	CS	FPS	HF.INST/CONST	5	1									1	
BWR	CS	FPS	HF.Welding Error	4	1						1				
BWR	CS	FPS	MIC - Microbiologically Induced Corrosion	3	1						1				
BWR	CS	FPS	Severe overloading	4	1							1			
BWR	CS	FPS	Severe Overloading	5	2									2	
BWR	CS	FPS	Vibration-fatigue	1	1									1	
BWR	CS	FPS	Vibration-fatigue	3	1								1		

BWR	SS	FWC	Corrosion	2	2									2	
BWR	SS	FWC	Corrosion	3	1				1						
BWR	SS	FWC	Corrosion	4	2									2	
BWR	SS	FWC	Corrosion	5	2									2	
BWR	SS	FWC	Corrosion	6	1									1	
BWR	SS	FWC	Corrosion-fatigue	2	1		1								
BWR	SS	FWC	Corrosion-fatigue	3	1									1	
BWR	SS	FWC	ECSCC - External Chloride Induced SCC	1	1						1				
BWR	SS	FWC	Erosion	2	2									2	
BWR	SS	FWC	Erosion	3	1						1				
BWR	SS	FWC	Erosion	4	1									1	
BWR	SS	FWC	Erosion	5	1									1	
BWR	SS	FWC	Erosion-cavitation	4	2		1				1				
BWR	SS	FWC	Erosion-cavitation	5	2						2				
BWR	SS	FWC	FAC - Flow Accelerated Corrosion	1	1									1	
BWR	SS	FWC	FAC - Flow Accelerated Corrosion	2	4					1				3	
BWR	SS	FWC	FAC - Flow Accelerated Corrosion	3	2				1					1	
BWR	SS	FWC	FAC - Flow Accelerated Corrosion	4	3						1			2	
BWR	SS	FWC	FAC - Flow Accelerated Corrosion	5	22		1			1	1	1		10	8
BWR	SS	FWC	FAC - Flow Accelerated Corrosion	6	20							2		1	17
BWR	SS	FWC	Fatigue	6	1									1	
BWR	SS	FWC	HF:CONST/INST	4	1									1	
BWR	SS	FWC	HF:CONST/INST	5	1									1	
BWR	SS	FWC	HF:CONST/INST	6	1		1								
BWR	SS	FWC	HF:Human error	1	1								1		
BWR	SS	FWC	HF:Welding Error	2	2									2	
BWR	SS	FWC	HF Welding error	5	1									1	
BWR	SS	FWC	IGSCC - Intergranular SCC	4	1						1				
BWR	SS	FWC	Severe overloading	1	1								1		
BWR	SS	FWC	Severe overloading	3	1							1			
BWR	SS	FWC	Severe overloading	4	1							1			
BWR	SS	FWC	Severe overloading	5	3							2		1	
BWR	SS	FWC	Severe overloading	6	1							1			
BWR	SS	FWC	SICC - Strain-rate Induced Corrosion Cracking	2	1									1	
BWR	SS	FWC	SICC - Strain-rate Induced Corrosion Cracking	4	1									1	
BWR	SS	FWC	SICC - Strain-rate Induced Corrosion Cracking	5	3		1							2	
BWR	SS	FWC	SICC - Strain-rate Induced Corrosion Cracking	6	4		3							1	
BWR	SS	FWC	Thermal fatigue	2	3									3	
BWR	SS	FWC	Thermal Fatigue	3	3		1			1		1			
BWR	SS	FWC	Thermal fatigue	5	5		5								
BWR	SS	FWC	Thermal fatigue	6	5		4							1	
BWR	SS	FWC	Unreported	3	1									1	
BWR	SS	FWC	Unreported	4	1									1	
BWR	SS	FWC	Unreported	6	2		1					1			
BWR	SS	FWC	Vibration-fatigue	1	2				1					1	
BWR	SS	FWC	Vibration-fatigue	2	21					1		3	2	15	
BWR	SS	FWC	Vibration-fatigue	3	8		1				1	1		6	
BWR	SS	FWC	Vibration-fatigue	4	3							1		2	
BWR	SS	FWC	Vibration-fatigue	5	5					1		1	1	2	
BWR	SS	FWC	Vibration-fatigue	6	1		1								
BWR	CS	IA-SA		2	1					1					
BWR	CS	IA-SA	Corrosion	2	1							1			
BWR	CS	IA-SA	Fretting	2	1					1					
BWR	CS	IA-SA	HF:Human error	1	1								1		
BWR	CS	IA-SA	IGSCC - Intergranular SCC	2	1									1	
BWR	CS	IA-SA	Severe Overloading	1	1								1		
BWR	CS	IA-SA	Severe Overloading	2	1									1	
BWR	CS	IA-SA	Vibration-fatigue	1	5					1		1	3		
BWR	CS	IA-SA	Vibration-Fatigue	2	4					1		1	1	1	
BWR	CS	PCS			1					1					
BWR	CS	PCS	Corrosion	1	1									1	
BWR	CS	PCS	Corrosion	3	1									1	
BWR	CS	PCS	Erosion	5	1									1	
BWR	CS	PCS	FAC - Flow Accelerated Corrosion	2	2				1					1	
BWR	CS	PCS	FAC - Flow Accelerated Corrosion	3	1									1	
BWR	CS	PCS	FAC - Flow Accelerated Corrosion	4	6									6	
BWR	CS	PCS	FAC - Flow Accelerated Corrosion	5	12							4		8	

BWR	CS	PCS	FAC - Flow Accelerated Corrosion	6	2							1		1	
BWR	CS	PCS	HF.Welding error	2	1									1	
BWR	CS	PCS	Severe overloading	2	2					1				1	
BWR	CS	PCS	Severe overloading	6	2							1		1	
BWR	CS	PCS	Thermal fatigue	2	1							1			
BWR	CS	PCS	Vibration-fatigue	1	1							1			
BWR	CS	PCS	Vibration-fatigue	2	7							4		3	
BWR	CS	PCS	Vibration-fatigue	3	1							1			
BWR	CS	PCS	Vibration-fatigue	4	2									2	
BWR	SS	RAS	Cavitation-erosion	5	1						1				
BWR	SS	RAS	Corrosion	2	3					2			1		
BWR	SS	RAS	Corrosion	3	4									4	
BWR	SS	RAS	Corrosion	4	6									6	
BWR	SS	RAS	Corrosion	5	3									3	
BWR	SS	RAS	Corrosion-fatigue	1	1									1	
BWR	SS	RAS	ECSCC - External Chloride Induced SCC	1	1									1	
BWR	SS	RAS	ECSCC - External Chloride Induced SCC	2	17		8							9	
BWR	SS	RAS	ECSCC - External Chloride Induced SCC	3	2	2									
BWR	SS	RAS	FAC - Flow Accelerated Corrosion	3	1						1				
BWR	SS	RAS	Fatigue	4	1		1								
BWR	SS	RAS	HF.CONST/INST	2	1									1	
BWR	SS	RAS	HF.CONST/INST	3	1						1				
BWR	SS	RAS	HF.CONST/INST	4	1									1	
BWR	SS	RAS	HF.CONST/INST	5	1									1	
BWR	SS	RAS	HF.Human error	1	1								1		
BWR	SS	RAS	HF:Human error	2	2				1				1		
BWR	SS	RAS	HF REPAIR/MAINT	1	1								1		
BWR	SS	RAS	HF REPAIR/MAINT	2	1									1	
BWR	SS	RAS	HF.REPAIR/MAINT	4	1		1								
BWR	SS	RAS	HF.Welding error	2	2						2				
BWR	SS	RAS	HF.Welding error	3	2						1			1	
BWR	SS	RAS	HF.Welding error	4	1									1	
BWR	SS	RAS	HF.Welding Error	5	4		1				1			2	
BWR	SS	RAS	IDSCC - Interdendritic SCC	4	1					1					
BWR	SS	RAS	IGSCC - Intergranular SCC	2	5						1			4	
BWR	SS	RAS	IGSCC - Intergranular SCC	3	4						2			2	
BWR	SS	RAS	IGSCC - Intergranular SCC	4	56	1	32				9		1	13	
BWR	SS	RAS	IGSCC - Intergranular SCC	5	56	2	35			4	8			7	
BWR	SS	RAS	IGSCC - Intergranular SCC	6	2		1				1				
BWR	SS	RAS	Severe overloading	1	1							1			
BWR	SS	RAS	Severe overloading	2	3			1				2			
BWR	SS	RAS	Severe overloading	4	1							1			
BWR	SS	RAS	TGSCC - Transgranular SCC	1	1									1	
BWR	SS	RAS	TGSCC - Transgranular SCC	2	7	1	1				1			4	
BWR	SS	RAS	TGSCC - Transgranular SCC	3	7		6							1	
BWR	SS	RAS	TGSCC - Transgranular SCC	4	96		96								
BWR	SS	RAS	TGSCC - Transgranular SCC	5	1					1					
BWR	SS	RAS	Thermal fatigue	1	1									1	
BWR	SS	RAS	Thermal fatigue	2	2						1			1	
BWR	SS	RAS	Thermal fatigue	3	1		1								
BWR	SS	RAS	Thermal Fatigue	4	1									1	
BWR	SS	RAS	Thermal fatigue	5	10		5							5	
BWR	SS	RAS	Thermal Fatigue - Cycling	4	3									3	
BWR	SS	RAS	Thermal Fatigue - Cycling	5	1		1								
BWR	SS	RAS	Thermal Fatigue - Cycling	6	1		1								
BWR	SS	RAS	Unreported	3	1		1								
BWR	SS	RAS	Unreported	5	1									1	
BWR	SS	RAS	Vibration-fatigue	1	4		1							3	
BWR	SS	RAS	Vibration-fatigue	2	15				1		1	1	1	11	
BWR	SS	RAS	Vibration-fatigue	3	7		1		1	1				4	
BWR	SS	RAS	Vibration-fatigue	4	2		1							1	
BWR	SS	RAS	Vibration-fatigue	5	1									1	
BWR	SS	RAS	Water Hammer	1	1				1						
BWR	SS	RCPB		2	1										1
BWR	SS	RCPB	Corrosion	1	1									1	
BWR	SS	RCPB	Corrosion	2	1						1				
BWR	SS	RCPB	ECSCC - External Chloride Induced SCC	1	3	2								1	

BWR	SS	RCPB	ECSCC - External Chloride Induced SCC	4	1		1								
BWR	SS	RCPB	Erosion	2	1					1					
BWR	SS	RCPB	external damage	3	1			1							
BWR	SS	RCPB	HF:CONSTANST	1	1						1				
BWR	SS	RCPB	HF:CONSTANST	6	2		2								
BWR	SS	RCPB	HF:Fabrication Error	2	1						1				
BWR	SS	RCPB	HF:Fabrication Error	3	1									1	
BWR	SS	RCPB	HF:Fabrication Error	6	1		1								
BWR	SS	RCPB	HF:REPAIR/MAINT	2	1									1	
BWR	SS	RCPB	HF:Welding error	1	1						1				
BWR	SS	RCPB	HF:Welding error	2	2									2	
BWR	SS	RCPB	HF:Welding Error	3	7	1				1	1			4	
BWR	SS	RCPB	HF:Welding error	5	1									1	
BWR	SS	RCPB	HF:Welding error	6	8		8								
BWR	SS	RCPB	Hot cracking	4	1									1	
BWR	SS	RCPB	IGSCC - Intergranular SCC	1	4		2			1				1	
BWR	SS	RCPB	IGSCC - Intergranular SCC	2	3						2			1	
BWR	SS	RCPB	IGSCC - Intergranular SCC	3	2						2				
BWR	SS	RCPB	IGSCC - Intergranular SCC	4	20	2	5			2	7			4	
BWR	SS	RCPB	IGSCC - Intergranular SCC	5	10		7			1	2				
BWR	SS	RCPB	IGSCC - Intergranular SCC	6	203	3	174			1	22			3	
BWR	SS	RCPB	Overpressurization	4	2	1						1			
BWR	SS	RCPB	Severe Overloading	4	1			1							
BWR	SS	RCPB	SICC - Strain-rate Induced Corrosion Cracking	6	1		1								
BWR	SS	RCPB	TGSCC - Transgranular SCC	1	1	1									
BWR	SS	RCPB	TGSCC - Transgranular SCC	2	1		1								
BWR	SS	RCPB	TGSCC - Transgranular SCC	3	1									1	
BWR	SS	RCPB	Thermal Fatigue	2	2									2	
BWR	SS	RCPB	Thermal Fatigue	3	1									1	
BWR	SS	RCPB	Vibration-fatigue	1	3									3	
BWR	SS	RCPB	Vibration-Fatigue	2	42	2	1			4	2			33	
BWR	SS	RCPB	Vibration-Fatigue	3	4									4	
BWR	SS	RCPB	Vibration-fatigue	4	1									1	
BWR	SS	RCS-INSTR	ECSCC - External Chloride Induced SCC	2	1		1								
BWR	SS	RCS-INSTR	ECSCC - External Chloride Induced SCC	3	1		1								
BWR	SS	RCS-INSTR	HF:Welding error	2	2					1				1	
BWR	SS	RCS-INSTR	IGSCC - Intergranular SCC	4	2						1			1	
BWR	SS	RCS-INSTR	TGSCC - Transgranular SCC	1	2					1				1	
BWR	SS	RCS-INSTR	TGSCC - Transgranular SCC	2	1									1	
BWR	SS	SIR		0	1	1									
BWR	SS	SIR	Brittle fracture	5	4		4								
BWR	SS	SIR	Corrosion	3	1									1	
BWR	SS	SIR	Corrosion-fatigue	5	1									1	
BWR	SS	SIR	ECSCC - External Chloride Induced SCC	1	1									1	
BWR	SS	SIR	ECSCC - External Chloride Induced SCC	6	1		1								
BWR	SS	SIR	Erosion	2	2						1			1	
BWR	SS	SIR	Erosion	5	1										1
BWR	SS	SIR	FAC - Flow Accelerated Corrosion	2	4									4	
BWR	SS	SIR	FAC - Flow Accelerated Corrosion	3	4				1					2	1
BWR	SS	SIR	FAC - Flow Accelerated Corrosion	4	2						1				1
BWR	SS	SIR	Fatigue	1	1									1	
BWR	SS	SIR	Fatigue	2	1					1					
BWR	SS	SIR	Fatigue	5	1									1	
BWR	SS	SIR	Fatigue	6	1									1	
BWR	SS	SIR	HF:CONSTANST	2	2									2	
BWR	SS	SIR	HF:CONSTANST	3	1									1	
BWR	SS	SIR	HF:CONSTANST	4	1										1
BWR	SS	SIR	HF:CONSTANST	5	1									1	
BWR	SS	SIR	HF:Fabrication Error	6	2		2								
BWR	SS	SIR	HF:Fabrication Error	6	1		1								
BWR	SS	SIR	HF:Human error	1	1									1	
BWR	SS	SIR	HF:Human error	2	1									1	
BWR	SS	SIR	HF:Welding Error	2	2									2	
BWR	SS	SIR	HF:Welding Error	4	1								1		
BWR	SS	SIR	HF:Welding Error	5	10		9			1					
BWR	SS	SIR	HF:Welding Error	6	6	1	2					1		2	
BWR	SS	SIR	IGSCC - Intergranular SCC	2	3	1	1							1	

BWR	SS	SIR	IGSCC - Intergranular SCC	4	4	1					2			1	
BWR	SS	SIR	IGSCC - Intergranular SCC	5	64	2	51				6			5	
BWR	SS	SIR	IGSCC - Intergranular SCC	6	22		18				4				
BWR	SS	SIR	MIC - Microbiologically Induced Corrosion	5	1							1			
BWR	SS	SIR	Overpressurization	6	1							1			
BWR	SS	SIR	Overstressed	2	2									2	
BWR	SS	SIR	Severe overloading	2	2								1	1	
BWR	SS	SIR	Severe overloading	4	1									1	
BWR	SS	SIR	Severe overloading	6	1			1							
BWR	SS	SIR	TGSCC - Transgranular SCC	5	1					1					
BWR	SS	SIR	TGSCC - Transgranular SCC	6	1		1								
BWR	SS	SIR	Thermal fatigue	2	3									3	
BWR	SS	SIR	Thermal fatigue	5	3		3								
BWR	SS	SIR	Thermal fatigue	6	1		1								
BWR	SS	SIR	Thermal Fatigue - Cycling	5	2		1							1	
BWR	SS	SIR	Unreported	5	1									1	
BWR	SS	SIR	Vibration-Fatigue	0	2					2					
BWR	SS	SIR	Vibration-fatigue	1	6		1							5	
BWR	SS	SIR	Vibration-fatigue	2	27		2			1	1	1	1	21	
BWR	SS	SIR	Vibration-fatigue	3	3		1							2	
BWR	SS	SIR	Vibration-fatigue	4	2									2	
BWR	SS	SIR	Vibration-fatigue	5	1									1	
BWR	SS	SIR	Vibration-fatigue	6	1				1						
BWR	CS	STEAM	Corrosion	2	1									1	
BWR	CS	STEAM	ECSCC - External Chloride Induced SCC	1	1							1			
BWR	CS	STEAM	Erosion	3	1									1	
BWR	CS	STEAM	Erosion	4	1									1	
BWR	CS	STEAM	FAC - Flow Accelerated Corrosion	2	16						3	1		12	
BWR	CS	STEAM	FAC - Flow Accelerated Corrosion	3	7									6	1
BWR	CS	STEAM	FAC - Flow Accelerated Corrosion	4	3									3	
BWR	CS	STEAM	FAC - Flow Accelerated Corrosion	5	7									7	
BWR	CS	STEAM	FAC - Flow Accelerated Corrosion	6	1									1	
BWR	CS	STEAM	Fatigue	2	3					1			1	1	
BWR	CS	STEAM	HF:CONSTANST	2	1									1	
BWR	CS	STEAM	HF:CONSTANST	3	1									1	
BWR	CS	STEAM	HF:CONSTANST	4	1					1					
BWR	CS	STEAM	HF:REPAIR/MAINT	1	1								1		
BWR	CS	STEAM	HF:Welding error	2	2									2	
BWR	CS	STEAM	HF:Welding error	3	2									2	
BWR	CS	STEAM	HF:Welding error	5	1					1					
BWR	CS	STEAM	HF:Welding Error	6	1		1								
BWR	CS	STEAM	IGSCC - Intergranular SCC	5	1		1								
BWR	CS	STEAM	Overpressurization	2	1							1			
BWR	CS	STEAM	Severe overloading	4	1							1			
BWR	CS	STEAM	SICC - Strain-rate Induced Corrosion Cracking	5	1		1								
BWR	CS	STEAM	SICC - Strain-rate Induced Corrosion Cracking	6	3		3								
BWR	CS	STEAM	TGSCC - Transgranular SCC	1	10		4			2				4	
BWR	CS	STEAM	TGSCC - Transgranular SCC	2	2		1							1	
BWR	CS	STEAM	Thermal fatigue	2	1									1	
BWR	CS	STEAM	Thermal fatigue	3	1									1	
BWR	CS	STEAM	Thermal fatigue	6	1									1	
BWR	CS	STEAM	Vibration-Fatigue	1	2							1		1	
BWR	CS	STEAM	Vibration-fatigue	2	12					1	1	2	2	6	
BWR	CS	STEAM	Vibration-fatigue	3	2									2	
BWR	CS	STEAM	Vibration-Fatigue	6	1									1	
BWR	CS	STEAM	Water Hammer	5	1		1								
BWR	CS	STEAM	Water Hammer	6	1			1							

Appendix B

Haddam Neck	PWR	CS	2.25	4	Erosion	GL 89-08
CANDU	PWR	CS	4	4	Thermal Fatigue	Korean
CANDU	PWR	CS	4	4	Thermal Fatigue	Korean
CANDU	PWR	CS	4	4	Thermal Fatigue	Korean
CANDU	PWR	CS	4	4	Thermal Fatigue	Korean
Millstone Unit 3	PWR	CS	6	5	Erosion/Corrosion	IN 91-18
Arkansas Nuclear One Unit 2	PWR	CS	14	6	Erosion	IN 89-53
DC Cook Unit 2	PWR	CS	16	6	Erosion	Bulletin 79-13
DC Cook Unit 2	PWR	CS	16	6	Erosion	Bulletin 79-13
Fort Calhoun Station	PWR	CS	12	6	FAC	IN 97-84
Surry Unit 1	PWR	CS	30	6	Not yet determined	IN 81-04
Surry Unit 2	PWR	CS	18	6	Erosion/Corrosion	IN 86-106
Trojan 1	PWR	CS	14	6	Erosion	IN 87-36
Zion 1	PWR	CS	24	6	Human Factor	IN 82-25
FR (Framatome Reactors)	PWR	CS	10	6	Corrosion	Korean
FR (Framatome Reactors)	PWR	CS	28	6	Corrosion	Korean
Diablo Canyon Unit	PWR	CS			Thermal Fatigue	IN 92-20
Lovilsa Unit 1	PWR	CS			Erosion/Corrosion	IN 91-18
Sequoyah Unit 1	PWR	CS			Thermal Fatigue	IN 92-20
Surry Unit 1	PWR	CS			Erosion/Corrosion	IN 91-18
Wolf Creek	PWR	SS	0.25	1	Vibration	IN 89-07
KSNP Korean Standard Nuclear Power Plant	PWR	SS	0.375	1	Thermal Fatigue	Korean
Oconee Unit 3	PWR	SS	0.75	1	Mechanical Failure	IN 92-15
WH-3	PWR	SS	0.75	1	Flow Induced Vibration	Korean
WH-3	PWR	SS	0.75	1	Flow Induced Vibration	Korean
H.B. Robinson Unit 2	PWR	SS	2	3	SCC	IN 91-05
Oconee Unit 2	PWR	SS	2	3	Vibration	IN 97-46
Prairie Island Unit 2	PWR	SS	2	3	SCC	IN 91-05
WH-3	PWR	SS	2	3	Flow Induced Vibration	Korean
WH-3	PWR	SS	2	3	Flow Induced Vibration	Korean
WH-3	PWR	SS	2	3	Flow Induced Vibration	Korean
Crystal River Unit 3	PWR	SS	2.5	4	Fatigue	IN 82-09
Fort Calhoun Station	PWR	SS	3.5	4	SCC	IN 82-02
Maine Yankee	PWR	SS	3.5	4	SCC	IN 82-02
Maine Yankee	PWR	SS	3.5	4	SCC	IN 82-02
Maine Yankee	PWR	SS	3.5	4	SCC	IN 82-02
Maine Yankee	PWR	SS	3.5	4	SCC	IN 82-02
Maine Yankee	PWR	SS	3.5	4	SCC	IN 82-02
Maine Yankee	PWR	SS	3.5	4	SCC	IN 82-02
Ginna	PWR	SS	8	5	SCC	IE Circular76-06
Foreign	PWR	SS	8	5	Thermal Stress	Bulletin 88-08
Arkansas Nuclear One Unit 1	PWR	SS	10	6	SCC	IE Circular76-06
Oconee Unit 2	PWR	SS	24	6	Erosion	IN 82-22
Sequoyah Unit 1	PWR	SS	16	6	Fatigue	IN 95-11
Sequoyah Unit 2	PWR	SS	10	6	Human Factor	IN 97-19
Surry Unit 2	PWR	SS	10	6	SCC	IE Circular76-06
Palo Verde	PWR	SS	Var		Human Factor	Bulletin 79-03
[illegible]	[illegible]	[illegible]	[illegible]		[illegible]	[illegible]

Appendix B (cont.)

Plant	Type	Material	Diameter	Pipe Size Group	Failure Mechanism	Reference
Dresden Unit 2	BWR	CS	4	4	Human Factor	Bulletin 74-10
Nine Mile Point Unit 2	BWR	CS	8	5	Fatigue	Event 36016
Vermont Yankee	BWR	CS	12	6	SCC	IN 82-22
Cooper Station	BWR	SS	0.25	1	Vibration	IN 89-07
Pilgrim	BWR	SS	1	2	Corrosion	IN 85-34
Browns Ferry 3	BWR	SS	4	4	SCC	IN 84-41
Browns Ferry 3	BWR	SS	4	4	SCC	IN 84-41
Nine Mile Point Unit 1	BWR	SS	6	5	SCC	Bulletin 76-04
Dreseden Unit 2	BWR	SS	10	6	Thermal Fatigue	IN 75-01
Dreseden Unit 2	BWR	SS	10	6	Thermal Fatigue	IN 75-01
Dreseden Unit 2	BWR	SS	10	6	Thermal Fatigue	IN 75-01
Dreseden Unit 2	BWR	SS	10	6	Thermal Fatigue	IN 75-01
Dreseden Unit 2	BWR	SS	10	6	Thermal Fatigue	IN 75-01
Hatch Unit 1	BWR	SS	22	6	SCC	IN 83-02
Hatch Unit 1	BWR	SS	22	6	SCC	IN 83-02
Hatch Unit 1	BWR	SS	22	6	SCC	IN 83-02
Hatch Unit 1	BWR	SS	22	6	SCC	IN 83-02
Hatch Unit 1	BWR	SS	22	6	SCC	IN 83-02
Hatch Unit 1	BWR	SS	20	6	SCC	IN 83-02
Hatch Unit 1	BWR	SS	24	6	SCC	IN 83-02
Montecello	BWR	SS	22	6	SCC	IN 83-02
Montecello	BWR	SS	12	6	SCC	IN 83-02
Montecello	BWR	SS	12	6	SCC	IN 83-02
Montecello	BWR	SS	12	6	SCC	IN 83-02
Montecello	BWR	SS	12	6	SCC	IN 83-02
Montecello	BWR	SS	12	6	SCC	IN 83-02
Browns Ferry 1	BWR					IN 82-24
Dresden Unit 1	BWR				Freezing	IN 94-38

Highlighted plants were not used in the data analysis due to missing information.

Appendix C. Collapsed OPDE Database

Collapsed OPDE Raw Data as function of Pipe Size

Plant Type	Pipe Size Group (inches)	Resulting Number of Failures		
		CS	SS	CS+SS
PWR	0.0-1.0	154	544	698
	1.0-2.0	74	154	228
	2.0-4.0	78	75	153
	4.0-10.0	126	112	238
	> 10.0	93	126	219
	Total	*525*	*1011*	*1536*
BWR	0.0-1.0	118	257	375
	1.0-2.0	32	75	107
	2.0-4.0	32	227	259
	4.0-10.0	50	234	284
	> 10.0	39	291	330
	Total	*271*	*1084*	*1355*
PWR+BWR	0.0-1.0	272	801	1073
	1.0-2.0	106	229	335
	2.0-4.0	110	302	412
	4.0-10.0	176	346	522
	> 10.0	132	417	549
	Total	*796*	*2095*	*2891*

Collapsed OPDE Raw Data as function of Failure Mechanism

Plant Type	Failure Mechanism	Resulting Number of Failures		
		CS	SS	CS+SS
PWR	Corrosion	106	28	134
	FAC	119	121	240
	MIC	43	1	44
	Erosion	96	12	108
	Fatigue	92	501	593
	Human Factors	36	126	162
	Mechanical Failures	22	37	59
	SCC	5	169	174
	Water Hammer	0	2	2
	Misc	6	14	20
	Total	*525*	*1011*	*1536*
BWR	Corrosion	29	32	61
	FAC	58	63	121
	MIC	6	1	7
	Erosion	40	9	49
	Fatigue	71	225	296
	Human Factors	24	85	109
	Mechanical Failures	18	25	43
	SCC	19	624	643
	Water Hammer	2	1	3
	Misc	4	19	23
	Total	*271*	*1084*	*1355*
PWR+BWR	Corrosion	135	60	195
	FAC	177	184	361
	MIC	49	2	51
	Erosion	136	21	157
	Fatigue	163	726	889
	Human Factors	60	211	271
	Mechanical Failures	40	62	102
	SCC	24	793	817
	Water Hammer	2	3	5
	Misc	10	33	43
	Total	*796*	*2095*	*2891*

NEC-UW_16

THIS EXHIBIT CONTAINS PROPRIETARY INFORMATION AND HAS BEEN REMOVED.

NEC-UW_17

THIS EXHIBIT CONTAINS PROPRIETARY INFORMATION AND HAS BEEN REMOVED.

Power Uprate History

Date	Reactor		Event
19770926	Calvert Cliffs	Unit 1	The NRC approved a 5.5 percent increase in the maximum licensed power level.
19770926	Calvert Cliffs	Unit 2	The NRC approved a 5.5 percent increase in the maximum licensed power level.
19790625	Millstone	Unit 2	The NRC approved a 5 percent increase in the maximum licensed power level.
19790629	H. B. Robinson	Unit 2	The NRC approved a 4.5 percent increase in the maximum licensed power level.
19800815	Fort Calhoun	Unit 1	The NRC approved a 5.6 percent increase in the maximum licensed power level.
19811123	St. Lucie	Unit 1	The NRC approved a 5.5 percent increase in the maximum licensed power level.
19850301	St. Lucie	Unit 2	The NRC approved a 5.5 percent increase in the maximum licensed power level.
19850327	Duane Arnold		The NRC approved a 4.1 percent increase in the maximum licensed power level.
19860206	Salem	Unit 1	The NRC approved a 2 percent increase in the maximum licensed power level.
19860825	North Anna	Unit 1	The NRC approved a 4.2 percent increase in the maximum licensed power level.
19860825	North Anna	Unit 2	The NRC approved a 4.2 percent increase in the maximum licensed power level.
19880330	Callaway	Unit 1	The NRC approved a 4.5 percent increase in the maximum licensed power level.
19880726	Three Mile Island	Unit 1	The NRC approved a 1.3 percent increase in the maximum licensed power level.
19920909	Fermi	Unit 2	The NRC approved a 4 percent increase in the maximum licensed power level.
19930322	Alvin W. Vogtle	Unit 1	The NRC approved a 4.5 percent increase in the maximum licensed power level.
19930322	Alvin W. Vogtle	Unit 2	The NRC approved a 4.5 percent increase in the maximum licensed power level.
19931110	Wolf Creek	Unit 1	The NRC approved a 4.5 percent increase in the maximum licensed power level.
19940411	Susquehanna	Unit 2	The NRC approved a 4.5 percent increase in the maximum licensed power level.
19941018	Peach Bottom	Unit 2	The NRC approved a 5 percent increase in the maximum licensed power level.
19950216	Limerick	Unit 2	The NRC approved a 5 percent increase in the maximum licensed power level.
19950222	Susquehanna	Unit 1	The NRC approved a 4.5 percent increase in the maximum licensed power level.
19950428	Nine Mile Point	Unit 2	The NRC approved a 4.3 percent increase in the maximum licensed power level.
19950502	Columbia Generating Sta		The NRC approved a 4.9 percent increase in the maximum licensed power level.
19950718	Peach Bottom	Unit 3	The NRC approved a 5 percent increase in the maximum licensed power level.
19950803	Surry	Unit 1	The NRC approved a 4.3 percent increase in the maximum licensed power level.
19950803	Surry	Unit 2	The NRC approved a 4.3 percent increase in the maximum licensed power level.
19950831	Edwin I. Hatch	Unit 1	The NRC approved a 5 percent increase in the maximum licensed power level.
19950831	Edwin I. Hatch	Unit 2	The NRC approved a 5 percent increase in the maximum licensed power level.
19960124	Limerick	Unit 1	The NRC approved a 5 percent increase in the maximum licensed power level.
19960412	Virgil C. Summer		The NRC approved a 4.5 percent increase in the maximum licensed power level.
19960523	Palo Verde	Unit 1	The NRC approved a 2 percent increase in the maximum licensed power level.
19960523	Palo Verde	Unit 2	The NRC approved a 2 percent increase in the maximum licensed power level.
19960523	Palo Verde	Unit 3	The NRC approved a 2 percent increase in the maximum licensed power level.
19960926	Turkey Point	Unit 3	The NRC approved a 4.5 percent increase in the maximum licensed power level.
19960926	Turkey Point	Unit 4	The NRC approved a 4.5 percent increase in the maximum licensed power level.
19961101	Brunswick	Unit 1	The NRC approved a 5 percent increase in the maximum licensed power level.
19961101	Brunswick	Unit 2	The NRC approved a 5 percent increase in the maximum licensed power level.

Power Uprate History

Date	Reactor		Event
19961206	James A. FitzPatrick		The NRC approved a 4 percent increase in the maximum licensed power level.
19980429	Joseph M. Farley	Unit 1	The NRC approved a 5 percent increase in the maximum licensed power level.
19980429	Joseph M. Farley	Unit 2	The NRC approved a 5 percent increase in the maximum licensed power level.
19980908	Browns Ferry	Unit 2	The NRC approved a 5 percent increase in the maximum licensed power level.
19980908	Browns Ferry	Unit 3	The NRC approved a 5 percent increase in the maximum licensed power level.
19980916	Monticello		The NRC approved a 6.3 percent increase in the maximum licensed power level.
19981022	Edwin I. Hatch	Unit 1	The NRC approved a 8 percent increase in the maximum licensed power level.
19981022	Edwin I. Hatch	Unit 2	The NRC approved a 8 percent increase in the maximum licensed power level.
19990930	Comanche Peak	Unit 1	The NRC approved a 1 percent increase in the maximum licensed power level.
20000509	LaSalle County	Unit 1	The NRC approved a 5 percent increase in the maximum licensed power level.
20000509	LaSalle County	Unit 2	The NRC approved a 5 percent increase in the maximum licensed power level.
20000601	Perry	Unit 1	The NRC approved a 5 percent increase in the maximum licensed power level.
20001006	River Bend	Unit 1	The NRC approved a 5 percent increase in the maximum licensed power level.
20001026	Diablo Canyon	Unit 1	The NRC approved a 2 percent increase in the maximum licensed power level.
20010119	Watts Bar	Unit 1	The NRC approved a 1.4 percent increase in the maximum licensed power level.
20010504	Braidwood	Unit 1	The NRC approved a 5 percent increase in the maximum licensed power level.
20010504	Braidwood	Unit 2	The NRC approved a 5 percent increase in the maximum licensed power level.
20010504	Byron	Unit 1	The NRC approved a 5 percent increase in the maximum licensed power level.
20010504	Byron	Unit 2	The NRC approved a 5 percent increase in the maximum licensed power level.
20010525	Salem	Unit 1	The NRC approved a 1.4 percent increase in the maximum licensed power level.
20010525	Salem	Unit 2	The NRC approved a 1.4 percent increase in the maximum licensed power level.
20010706	San Onofre	Unit 2	The NRC issued license amendment 180 increasing the maximum reactor power level to 3,438 megawatts from 3,390 megawatts.
20010706	San Onofre	Unit 2	The NRC approved a 1.4 percent increase in the maximum licensed power level.
20010706	San Onofre	Unit 3	The NRC approved a 1.4 percent increase in the maximum licensed power level.
20010706	San Onofre	Unit 3	The NRC issued license amendment 171 increasing the maximum reactor power level to 3,438 megawatts from 3,390 megawatts.
20010706	Susquehanna	Unit 1	The NRC approved a 1.4 percent increase in the maximum licensed power level.
20010706	Susquehanna	Unit 2	The NRC approved a 1.4 percent increase in the maximum licensed power level.
20010719	San Onofre	Unit 3	The NRC issued license amendment raising maximum reactor power level to 3,438 megawatts.
20010730	Hope Creek	Unit 1	The NRC approved a 1.4 percent increase in the maximum licensed power level.
20010924	Beaver Valley	Unit 1	The NRC approved a 1.4 percent increase in the maximum licensed power level.
20010924	Beaver Valley	Unit 2	The NRC approved a 1.4 percent increase in the maximum licensed power level.
20011012	Comanche Peak	Unit 1	The NRC approved a 1.4 percent increase in the maximum licensed power level.
20011012	Comanche Peak	Unit 2	The NRC approved a 0.4 percent increase in the maximum licensed power level.
20011012	Shearon Harris	Unit 1	The NRC approved a 4.5 percent increase in the maximum licensed power level.
20011106	Duane Arnold		The NRC approved a 15.3 percent increase in the maximum licensed power level.

Power Uprate History

Date	Reactor		Event
20011107	Duane Arnold		The NRC issued license amendment 243 increasing the maximum reactor power level to 1,912 megawatts.
20011221	Dresden	Unit 2	The NRC approved a 17 percent increase in the maximum licensed power level.
20011221	Dresden	Unit 3	The NRC approved a 17 percent increase in the maximum licensed power level.
20011221	Quad Cities	Unit 1	The NRC approved a 17.8 percent increase in the maximum licensed power level.
20011221	Quad Cities	Unit 2	The NRC approved a 17.8 percent increase in the maximum licensed power level.
20020329	Waterford	Unit 3	The NRC approved a 1.5 percent increase in the maximum licensed power level.
20020405	Clinton	Unit 1	The NRC approved a 20 percent increase in the maximum licensed power level.
20020412	South Texas Project	Unit 1	The NRC approved a 1.4 percent increase in the maximum licensed power level.
20020412	South Texas Project	Unit 2	The NRC approved a 1.4 percent increase in the maximum licensed power level.
20020424	Arkansas Nuclear One	Unit 2	The NRC approved a 7.5 percent increase in the maximum licensed power level.
20020430	Sequoyah	Unit 1	The NRC approved a 1.4 percent increase in the maximum licensed power level.
20020430	Sequoyah	Unit 2	The NRC approved a 1.4 percent increase in the maximum licensed power level.
20020531	Brunswick	Unit 1	The NRC approved a 15 percent increase in the maximum licensed power level.
20020531	Brunswick	Unit 2	The NRC approved a 15 percent increase in the maximum licensed power level.
20021010	Grand Gulf	Unit 1	The NRC approved a 1.7 percent increase in the maximum licensed power level.
20021105	H. B. Robinson	Unit 2	The NRC approved a 1.7 percent increase in the maximum licensed power level.
20021122	Peach Bottom	Unit 2	The NRC approved a 1.62 percent increase in the maximum licensed power level.
20021122	Peach Bottom	Unit 3	The NRC approved a 1.62 percent increase in the maximum licensed power level.
20021126	Indian Point	Unit 3	The NRC approved a 1.4 percent increase in the maximum licensed power level.
20021129	Point Beach	Unit 1	The NRC approved a 1.4 percent increase in the maximum licensed power level.
20021129	Point Beach	Unit 2	The NRC approved a 1.4 percent increase in the maximum licensed power level.
20021204	Crystal River	Unit 3	The NRC approved a 0.9 percent increase in the maximum licensed power level.
20021220	Donald C. Cook	Unit 1	The NRC approved a 1.66 percent increase in the maximum licensed power level.
20030131	River Bend	Unit 1	The NRC approved a 1.7 percent increase in the maximum licensed power level.
20030204	Crystal River	Unit 3	The NRC approved license amendment 205 increasing the maximum reactor power level to 2,568 megawatts.
20030502	Donald C. Cook	Unit 2	The NRC approved a 1.66 percent increase in the maximum licensed power level.
20030509	Pilgrim	Unit 1	The NRC approved a 1.5 percent increase in the maximum licensed power level.
20030522	Indian Point	Unit 2	The NRC approved a 1.4 percent increase in the maximum licensed power level.
20030523	Indian Point	Unit 2	The NRC issued license amendment 237 increasing the maximum reactor power level to 3,114.4 megawatts.
20030708	Kewaunee		The NRC approved a 1.4 percent increase in the maximum licensed power level.
20030923	Edwin I. Hatch	Unit 1	The NRC approved a 1.5 percent increase in the maximum licensed power level.
20030923	Edwin I. Hatch	Unit 2	The NRC approved a 1.5 percent increase in the maximum licensed power level.
20030929	Palo Verde	Unit 2	The NRC approved a 2.9 percent increase in the maximum licensed power level.
20040227	Kewaunee		The NRC approved a 6 percent increase in the maximum licensed power level.
20040623	Palisades		The NRC approved a 1.4 percent increase in the maximum licensed power level.
20041028	Indian Point	Unit 2	The NRC approved a 3.26 percent increase in the maximum licensed power level.

Power Uprate History

Date	Reactor		Event
20050228	Seabrook	Unit 1	The NRC approved a 5.2 percent increase in the maximum licensed power level.
20050324	Indian Point	Unit 3	The NRC approved a 4.85 percent increase in the maximum licensed power level.
20050415	Waterford	Unit 3	The NRC approved a 8 percent increase in the maximum licensed power level.
20051116	Palo Verde	Unit 1	The NRC approved a 2.9 percent increase in the maximum licensed power level.
20051116	Palo Verde	Unit 3	The NRC approved a 2.9 percent increase in the maximum licensed power level.
20060302	Vermont Yankee		The NRC approved a 20 percent increase in the maximum licensed power level.
20060522	Seabrook	Unit 1	The NRC approved a 1.7 percent increase in the maximum licensed power level.
20060711	R. E. Ginna		The NRC approved a 16.8 percent increase in the maximum licensed power level.
20060719	Beaver Valley	Unit 1	The NRC approved a 8 percent increase in the maximum licensed power level.
20060719	Beaver Valley	Unit 2	The NRC approved a 8 percent increase in the maximum licensed power level.
20070306	Browns Ferry	Unit 1	The NRC approved a 5 percent increase in the maximum licensed power level.

VERMONT YANKEE NUCLEAR POWER STATION

PROGRAM PROCEDURE

PP7028

ORIGINAL

PIPING FLOW ACCELERATED CORROSION INSPECTION PROGRAM

USE CLASSIFICATION: **INFORMATION**

LPC No.	Effective Date	Affected Pages
1	12/06/01	3-5 & 13-15 of 15

Implementation Statement: This procedure supercedes VY Procedure DP 4023 and use of the Vermont Yankee Piping Flow Accelerated Corrosion Program Manual, Revision 2a, prepared for Vermont Yankee by Yankee Atomic - Nuclear Services Division.

Issue Date: 05/10/01

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1.0 PURPOSE, SCOPE, AND DISCUSSION

1.1. Purpose

The purpose of the Vermont Yankee Piping Flow Accelerated Corrosion (FAC) Inspection Program is to provide a systematic approach to ensure that PAC does not lead to degradation of plant piping systems and feedwater heaters. This Program Procedure controls the engineering and inspection activities performed to predict, detect, monitor, and evaluate wall thinning due to PAC at the Vermont Yankee Nuclear Power Station.

1.2. Scope

LPC 1

The scope of this program is limited to evaluation and inspection of plant piping systems and feedwater heater shells that could be susceptible to FAC.

FAC is known to occur in piping systems constructed of carbon or low-alloy steels, which carry water or wet steam. All plant piping systems have been screened for susceptibility to damage from FAC. A separate document titled "FAC Susceptible Piping Identification" has been developed to identify, on a line by line basis, the piping which is susceptible to damage from FAC. This document is maintained by the Piping FAC Inspection Program coordinator and is updated as required to reflect changes in plant operation and configuration.

There is no finite scope of piping components to be scheduled for inspection on a periodic basis. Each refueling outage inspection efforts will be optimized to focus on piping components which have been identified as wearing, or potentially wearing due to FAC. The components selected for inspection each refueling outage are identified using:

- Results of ultrasonic thickness (UT) inspections from previous refueling outages.
- Results of the CHECWORKS predictive software, which incorporates actual inspection data.
- Operating conditions at VY, which may indicate PAC damage is occurring.
- Operating experience and events from other plants.

Carbon steel feedwater heater shells have experienced thinning and through wall leaks due to PAC. Vermont Yankee has replaced all low pressure feedwater heaters with new heaters constructed of materials resistant to FAC. The four remaining high pressure feedwater heater shells are carbon steel. Long term monitoring of shell thickness for plant feedwater heaters is included in the scope of this program.

1.3. Discussion

Following the December 1986 Surry pipe rupture the industry has worked steadily to develop and implement monitoring programs to prevent the rupture of high energy piping due to single phase erosion-corrosion (FAC). In March 1987 INFO issued Significant Operating Experience Report (SOER) 87-3 which recommended that a continuing program be established at all U.S. nuclear power plants including analyses to predict wear rates and to plan and schedule periodic inspections. USNRC Generic Letter GL 89-08, requires all holders of operating licenses to provide assurances that a systematic program has been implemented to ensure that Flow Accelerated Corrosion does not lead to degradation of plant piping systems.

This Program Procedure (PP) controls engineering and inspection activities performed to assess the susceptible plant piping. This procedure defines the methods and criteria used in the evaluation and inspection of plant piping components which are susceptible to wall thinning due to FAC. The program is based on current industry practice and the latest EPRI recommendations (REF 5.4.8.).

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Long term monitoring of plant feedwater heater shell thickness is included in the scope of this program. Previous heater inspection efforts were performed by Project Engineering and Design Engineering in conjunction with feedwater heater repair and replacement efforts. All six of the low pressure feedwater heaters have been replaced with new heaters constructed of materials resistant to FAC. The four remaining high pressure feedwater heater shells are carbon steel. Design criteria used in the feedwater heater repair and replacement activities are included in the documentation for the corresponding design change or work order which implemented the repair or replacement.

Overall health of the feedwater heaters is not only determined by the condition of the shell and nozzles, but is also dependent on the condition of the heater internals: tubes, tube support plates, impingement plates, tie rods, drain cooler end plates, etc. Evaluation of the overall component health is the responsibility of the Maintenance Department. Shell and nozzle inspections of feedwater heaters will be coordinated through the responsible System Engineer and the Maintenance Support Department. UT inspections of the heater shells will be performed in conjunction with internal visual inspections and eddy current testing of the heater tubes under Preventive Maintenance (PM) work orders.

Elements of the program controlled by this procedure are:

- Criteria for selection of piping systems and components susceptible to FAC and for maintenance of a "FAC Susceptible Piping Identification", which identifies all plant piping susceptible to FAC.
- Criteria for ongoing program maintenance including; benchmarking with current industry practice, evaluation of industry events, and participation in industry working groups.
- Criteria for use and control of the CHECWORKS predictive software used to evaluate piping, plan inspections, track inspection results, wear rates, piping component data, and repair and/or replacement history.
- Criteria for selection and scheduling of components to be inspected during refueling outages including initial inspections, follow-on inspections, and scope expansion / reduction.
- Criteria and procedures for evaluation of thinned piping components and, if required, for repair and replacements.
- Documentation requirements and criteria for maintenance and storage of inspection data.

NOTE

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The program only addresses wall thinning due to FAC in pressure boundary piping components and feedwater heater shells. Wear in other pressure vessels, pumps, valves, and in-line items is not included. However, detected wear in the attached piping may indicate wear in the component and should be ursued.

The primary purpose of performing UT inspections each outage is to locate piping components degraded by FAC prior to the time that an immediate repair or replacement is reqnired. This allows sufficient lead time for a planned replacement which will have a minimum impact on plant operation.

Given the costs of inspection and replacement of piping components, a long term approach for mitigating the effects of FAC taken under this program will be towards reducing component wear rates. To accomplish this, components found with significant wall loss due to FAC under this program, will be preferably replaced with materials which are more resistant to FAC damage.

2.0 DEFINITIONS

2.1. Flow Accelerated Corrosion (FAC): A corrosion process that causes thinning of steel piping exposed to flowing water or wet steam. The rate of loss is dependent on several parameters, which include flow regime, service life, water chemistry, piping material, piping geometry, and hydrodynamics.

LPC 1

2.2. Program: A set of activities that benefit from the existence of a formal, high level "Program Document." Such documents are meant to provide for a common understanding of program depth, breath and technical bases as well as the responsibilities of the program owner and those helping to implement the program. "Program Documents" are typically created to ensure regulatory requirements are satisfied. They can also be used to layout the technical bases and personnel responsibilities related to complex, multi-departmental processes.

2.3. Program Owner: The individual responsible for maintaining the program, program documents, and assuring proper execution of the program requirements. Each program shall have an individual assigned as the program owner. The appropriate Job title is determined by the responsible Department Manager. A summary of expectations for the program owner are contained in Appendix A of AP 0098 and shall be referenced in all Program Procedures.

2.4. Single-Phase Flow: The flow in the piping system remains in the liquid phase at all design and operating pressures and temperatures.

2.5. Two-Phase Flow: The flow in the piping system may vary from liquid to wet steam. This depends on the operating pressures and temperatures and varies with the specific location in the piping system.

3.0 PRIMARY RESPONSIBILITIES

Implementation of the tasks performed under this program involve several plant departments. The organization for personnel performing tasks under this program is shown in Figure 1.

3.1. The VY Design Engineering Mechanical! Structural (DE *MIS)* Department is responsible for the Piping FAC Inspection Program. The DE MIS Lead Design Engineer (LDE) has responsibility for the overall program management and administration and, for structural evaluation of thinned piping components.

3.1.1. Establishment and maintenance of criteria and procedures for evaluation of thinned wall piping components.

3.1.2. Performing structural evaluations of thinned wall piping components.

3.2. The Vermont Yankee Piping FAC Inspection Program Coordinator (FACPC) works within the Mechanical Structural (DE *MIS)* Department under the direction of the DE MIS LOE. The responsibilities of the FAC Program Coordinator are:

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3.2.1. Maintenance of the Vermont Yankee Piping FAC Inspection Program Procedure and supporting documents to ensure that program meets commitments to GL 89-08 and the "Expectations of Program Owners" as defined in Appendix A of AP 0098.

3.2.2. Continual assessment of FAC inspection program to insure program effectiveness.

3.2.3. Participation in relevant industry working groups, benchmarking with current industry practice, evaluation of industry events; and implementation of revisions, changes, and process improvements which result from the participation.

3.2.4. Establishment and maintenance of criteria for selection of piping systems and components susceptible to FAC and for maintenance of the "FAC Susceptible Piping Identification" document which screens all current plant piping systems and identifies piping susceptible to FAG

3.2.5. Establishment and maintenance of criteria for selection and scheduling of components to be inspected during refueling outages including: initial inspections, follow-on inspections, and scope expansion and/or reduction.

3.2.6. Establishment and maintenance of criteria for use and control of the CHECWORKS predictive software used to evaluate piping, plan inspections, track inspection results, wear rates, piping component data, and repair and/or replacement history.

3.2.7. Review of design change and maintenance documents as necessary to assess the impact of the proposed tasks on the inspection program, and recommend action when appropriate.

3.2.8. Ensure that all physical and operational changes or additions to plant piping systems are incorporated into the program.

3.2.9, Analytical evaluation of plant piping systems for FAC using the EPRI CHECWORKS codes as appropriate.

3.2.10. Pre-outage activities including:

- Development of inspection scope for each refueling outage.
- Perform/update analytical evaluations (CHECWORKS models) as required.
- Provide pre-inspection implementation support.

3.2.11. Outage activities including:

- Providing engineering support for inspection implementation.
- Evaluation and disposition of all inspection results.
- Recommend changes to the planned inspection scope upon discovery of unacceptable conditions.
- Providing assistance as required in the development of repair/replacement options.
- Providing written summary of inspection results to ISIPC prior to plant startup.
- Ensure that cognizant departments and the Control Room are informed of unacceptable conditions discovered during evaluation of inspection results and facilitate completion of appropriate paperwork (ER's, WOR, IDR, etc.).

3.2.12. Post-outage activities including:

- Development of outage inspection report including trending analyses and long term recommendations.
- Update/maintain the plant CHECWORKS models and maintain a history of all piping inspections.
- Update/maintain "FAC Susceptible Piping Identification" document to reflect plant changes as required.

3.2.13. Keep DE *MIS* LDE informed on the progress of FAC related tasks.

3.3. The Vennont Yankee In-Service Inspection Program Coordinator (ISIPC): works within the System Engineering Department under the direction of the Superintendent of System Engineering. The responsibilities of the ISIPC include:

3.3.1. Provide for overall coordination with the Vermont Yankee In-Service Inspection Program if inspection results on safety class piping indicate violations of the piping design code.

3.3.2. Coordination of pre-outage activities including:

- Input to the development of outage schedules and budgets relative to FAC activities.
- Providing oversight of work order planning and coordination with ISI Program resources.
- Arrange on-site services as required.

3.3.3. Coordination of outage activities including:

- Ensure components scheduled for inspection are properly prepared and accessible.
- Perfonnance of inspections.
- Post inspection restoration of components.
- Repair/replacement effort of unacceptable components.

3.3.4. Interface with the cognizant departments, as needed to insure all safety related repair/replacement ISI examination requirements are satisfied.

3.3.5. Ensure that required piping repairs and/or replacements are perfonned according to plant procedures and repairs to safety class piping and components are performed in accordance with ASME Section XI requirements.

3.3.6. Ensure that cognizant departments and the Control Room are informed of unacceptable conditions discovered during evaluation of inspection results and facilitate completion of appropriate paperwork (ER's, WOR, IDR, etc.).

3.3.7. Ensure that inspection records are temporarily stored per AP 6807 and permanently stored per AP 6809 and available far the plant lifetime.

3.3.8. Keep the Superintendent af System Engineering informed on the progress af FAC related tasks.

3.3.9. Provide technical advice on implementation and inspection aspects of the FAC program.

3.3.10. NDE procedure development and maintenance.

3.4. Level III / ISI Supervisor is a certified Level III UT examiner and works under the direction of the ISIPC. The responsibilities of the Level III /ISI Supervisor include:

3.4.1. Review of applicable NDE procedures used in pipe tJT wall thickness measurements.

3.4.2. Ensuring that UT inspectors are properly qualified and trained to the applicable inspection procedures.

3.4.3. Review of inspection results for compliance to the applicable procedures.

3.4.4. Resolution of anomalies found in inspection data.

3.4.5. Recommendations for augmented or special NDE procedures or techniques as required.

3.4.6. Direct supervision of inspection personnel to ensure that the inspection personnel accurately and efficiently execute the inspection plan, complete inspections, and appropriately document inspection results.

3.4.7. Control of all inspection data during the refueling outage.

3.4.8. At the completion of inspections forwarding all inspection records to the ISIPC for pennanent storage per the requirements of Section 6.2

3.5. Non Destructive Examination (NDE) Personnel

3.5.1. Meet Applicable qualification Standards. Personnel perfonning ultrasonic inspections shall be qualified to the requirements of NE 8043.

3.5.2. Perfonn assigned setup, calibrations, and examinations.

3.5.3. Documentation of results in accordance with approved procedures.

3.6. Plant Support Services

The Project Engineering Department is responsible for providing staging, lighting, insulation removal, surface preparation of piping components, and for component restoration after inspections are performed. Activities are controlled through the VY Work Order process in accordance with plant procedures.

4.0 PROCEDURE

4.1. Program Maintenance

The FACPC shall maintain the Yankee Piping FAC Inspection Program Procedure, PP 7028 and supporting documents to ensure that program meets commitments to GL 89-08 by:

4.1.1. Continual reassessment of the piping FAC inspection program to insure program effectiveness. A FAC Program Self Assessment shall be performed at least once per operating cycle.

4.1.2. Participation in relevant industry working groups, benchmarking with current industry practice, evaluation of industry events; and implementation of revisions, changes, and process improvements which result from the participation.

4.1.3. Adaptation of current or developing industry practices: for selection and scheduling of components to be inspected, follow-on inspections, scope expansion and/or reductions, and criteria and procedures for evaluation of thinned wall piping components.

4.1.4. Review design change and maintenance documents as necessary to assess the impact of the proposed tasks on the inspection program, and recommend action when appropriate.

4.1.5. Incorporate all physical and operational changes or additions to plant piping systems into the program as applicable.

4.2. Initial Screening and Identification of FAC Susceptible Piping

4.2.1. A screening and evaluation of all plant piping systems for susceptibility to FAC shall be performed. The screening shall use the EPRI Guidelines from reference 5.4.8., industry experience, and previous Vermont Yankee inspection results. The evaluation shall be performed and reviewed by engineers with FAC experience and familiar with plant systems. The resulting document shall be controlled by the FACPC.

4.2.2. The FACPC shall revise the "FAC Susceptible Piping Identification" document as required to reflect changes in plant operation, piping configuration, and/or materials.

4.3. CHECWORKS Modeling

4.3.1. Evaluate the susceptible plant piping systems for FAC using the EPRI CHECWORKS code. The evaluations shall be performed, reviewed, and documented per the requirements of Appendix D.

4.4. Outage to Outage Activities

Inspection and evaluation efforts performed under the program follow a cyclic pattern. Once inspection data from a given outage is obtained, it is incorporated into the appropriate predictive model and the results are then used in conjunction with other FAC related information to establish the inspection scope for the next refueling outage.

NOTE

Each large bore piping component within the scope ofthis program has been given a unique identification number as described in Appendix A. The location (building and elevation) ofeach large bore component is obtained from the Component Location Sketches in Appendix A. Small bore piping inspection locations included in the program are identified in Appendix B.

The tasks performed each refueling outage to implement the piping inspections under the FAC inspection program are detailed below. These are also broken out chronologically in a flow chart included here as Figure 2.

4.4.1. The outage inspection scope is determined by the FACPC using previous inspection data, the results ofthe CHECWORKS models, industry experience, and the guidelines contained in Appendix E.

4.4.2. The outage inspection scope is reviewed by the ISIPC for impact on and conflicts with the overall outage plan. The ISIPC will plan and organize the on-site resources required to implement the piping inspections.

4.4.3. A work package is assembled for each piping component or group ofcomponents. This package includes component location sketches, support requirements such as scaffolding, lighting, etc., surface preparation and gridding requirements, and any special inspection requirements as determined by the FACPC.

4.4.4. Prepare piping components for inspection.

4.4.4.1. As directed by the ISIPC, scaffolding, lighting, insulation removal, and surface preparation ofeach piping component to be inspected are performed by on-site services in accordance with the applicable plant procedures.

4.4.4.2. Surface preparation and gridding ofpiping components for inspection shall conform to the guidelines in NSAC 202L (reference 5.4.8.). Specific instructions for surface preparation are given in NE 8044. Specific instructions for gridding ofpiping components are given in Attachment A ofNE 8053, or as further directed by the FACPC.

PP7028 Piping FACJnspectIon Program

FAC INSPECTION PROGRAM RECORDS FOR 2005 REFUELING OUTAGE

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ENN Nuclear Management Manual Non QA Administrative Procedure
ENN-DC-183 Rev.1 Facsimile of Attachment 9.10
Program or Component Scoping Memorandum

TAB 1

2004-2005 Program Scope **Memo**
Vermont Yankee - Engineering **Department**

WBS Element: **FAC** Inspection **Program** Pro'eel Number:
Title: Piping Flow Accelerated Corrosion (FAC) Inspection Program 2004 & 2005 Prooram Related Efforts
Department: **Design Engineering – Mechanical / Structural**
[redacted] Owner: **James Fitzpatrick**
Backuo: **Thomas O'Connor**
Procedure No. & Tille: **PP 7028****, Vermont Yankee Piping Flow Accelerated Corrosion **Inspection** Prooram

Detailed Scope of Project (Explanation): Engineering activities to support ongoing Inspection Program 10 provide a systemalic approach to insure thai Flow Accelerated Corrosion (FAC) does not lead to degradation of plant piping systems. Currently" Program Procedure PP 7028 controls engineering and inspection activities to predict, detect, monitor, and evaiuate pipe wall thinning due to FAC. Activities include modeling of plant piping using the EPRI CHECWORKS code to predict susceptibility to FAC damage, selection of components for inspection, UT inspections of piping components, evaiuation of data, trending, monitoring of industry events and best practices, participation in industry groups, and recommending future repairs and *lor* replacements prior to component failure.

** Expected to adopt a new ENN Standard Program Procedure ENN-DC-315 (which is currently under development with an accelerated deveiopment date of 6!30!04),

Expected Benefits (Justification): VY committed to have an effective piping FAC inspection program in response to G1 89-08.

Consequences of **Deferral**: Possible hazards to plant personnel, Loss of plant availability, unscheduled repairs, and deviationlrom previous regulatory commitments.

Duration of Program: Life of plant

2004 Key Deliverables or Milestones:	Completion Estimate
Compiete Focused SA write up & generate appropriate corrective actions' (coordinate aclivities with program standardization efforts).	6/18104
Completion of RFO 24 documentation, write and issue RFO 2004 Inspection Report	7/23/04
Software QA on XP platform for CHECWORKS FAC module Version 1.0G	8/13/04
Issue 2005 RFO Outage Inspection Scope. Including Scoping worksheets.	9/1/04
Update Piping FAC susceptibility screening'To account for piping and drawing updates_ Include effects from NMWC, power uprate, & life extension.	8/13/04
Update piping Small Bore piping database and develop new priority iogic for inspection scheduling,	10/01/04

1 of 4

[redacted]	Completion Estimate
Update CHECWORKS models using Version 1.0G with latest 2002 RFO & 2004 RFO Inspection data *(Note ideally results are to be used in determining the 2005 inspection scope, however schedule milestones override program logic.)*	12/31/04
Adoption of ENN-DC-315 ENN Standard FAC program Procedure to include all previous improvements identified Self Assessments.	~~10/31/04~~
Ongoing Program Maintenance, Includes: procedure revisions, program improvements, benchmarking, attendance at industry (EPRI CHUG) meetings, evaluation of industry events (industry awareness) fo[redacted]effects on VY, license renewal nroject Innut, and fleet support.	12/31/04
2[redacted]5 **Kev Deliverables or Milestones:**	
Perform Program Self Assessment minimum once per cvcle).	4/1/05
C[redacted]version of CHECHWORKS1,OG models to SFA VersiOII 2,1x	9/1/05
RFO 25 sup art	11/15/05
Completioll of RFO 25 documentation, develop RFO 25 Outage Illsnection Report	12/31/05
Ongoing Program Maintellance, Includes; procedure revisions, program improvements, benchmarking, attendance at industry (EPRI CHUG) meetings, evaluation of industry events (industry awareness) for effects on VY, and fleet support.	12/31/05
[redacted]	
Issue 2005 Outage Inspectioll Report	1/15/06
U ate SFA Predictive ModelS with 2005 RFO data	4/15/06
Ongoing Program Maintenance. Includes: procedure re program improvements, benchmarking, attendance at industry (EPRI CHUG) meetings, evaluation of industry events (Industry awareness) for effects on VY, and fleet sunnort.	12/31/06

Estimated Bud ret or Ex enses:	AmountIHrs
Ca tured in DE Mech.IStructural Base Bud at	N/A

others Impacted B Pro ect:	Estimated Hours
S tem En ineerin	40
[redacted]	
Desi n En ineerin	
FlUid S tems En ineerin	40
Electrical!I&C En ineerin	
Mechanical! Strucwral Desi n	

Level 3 F nel: Attached

Performance Indicators for FAC Program are contained in the Program Health Report (Attached)

2 of 4

2004-2005 Piping FAC Inspe‹ ›on Program Level 3 Fragnet

YEAR 2004 {2nd half} (Time Line from 6/01/04 to 12/31/04)

Task No.	Task Description	Preparer (HRS) Estimated	Reviewer (HRS) Estimated.	TOTAL (HRS) Estimated.	Est. Start	Est. Delivery 1Completion Date
04-1	Complete Focused SA write up & generate appropriate corrective actions (coordinate activities with program standardization efforts).	20	10	30	611/04	6/18104
04-2	Completion of RFo 24 documentation, write and issue RFO 2004 Inspection Report	60	30	90	6114104	7/23104
04-3	Software QA on XP platform fur CHECWORKS FAC module Version 1.0G	20	10	30	I 711/04	8/13/04
04-4	Update Piping FAC susceptibility screening to account fur piping and drawing updates. Include effects from NMWC, power uprate, & life extension.	40	20	60	7/12104	8113/04
04-5	Update piping Small bore piping database and develop new priority logic for inspection scheduling.	40	20	60	9/6104	10101/04
04-6	Update CHECWORKS models using Version 1.0G with latest 2002 RFO &2004 RFO Inspection data	160	80	240	8/23/04	12131104
04-7	Issue 2005 RFO Outage Inspection Scope. InclUding Seaping worksheets.	40	20	60	812104	911/04
04-8	Development/adoption of ENN-DC-315 ENN Standard FAC program Procedure to include all previous improvements identified Self Assessments.	80	40	120	6/2/04	10131104
04-9	Ongoing Program Maintenance. Includes: procedure revisions, program improvements, benchmarking, attendance at industry (EPRI CHUG) meetings, evaluation of industry events (industry awareness) for effects on W, LR project input, and fleet support.	160	40	200	6/1/04	12/31104
TOTAL HRS	{From end of RFO 24 to December 31, 2004}	620	270	890		

3of4

NEC037102

2004-2005 Piping FAC Inspe… on Program Level 3 Fragnet

YEAR 2005 (1/1/05 TO 12/31/05)

Task No.	Task D&scrlptlon	Preparer (HRS) Estimated	Reviewer (HRS) Estimated.	TOTAL (HRS) Estimated.	Est. Start	Est. Delivery / Completion Date
05-1	Perform Program Self Assessment (minimum once per cycle).	40	20	60	3/1/05	4/01/05
05-2	Conversion of CHECHWORKS 1.0G models to SFA Version 2.1x	360	160	540	411/05	9/01/05
05-3	RFO 25 Preparation & Outage Support	160	60	240	9/1/05	1111510504
05-4	Completion of RFO 25 documentation, develop RFO 25 Outage Inspection Report	60	30	90	11115/05	12/31105
05-5	Ongoing Program Maintenance. Includes: procedure revisions, program improvements, benchmarking, attendance at industry (EPRI CHUG) meetings, evaluation or industry events (industry awareness) ~~for effects on VY. and fleet su art.~~	40	20	60	1/01/05	112/31/05
Total Hrs				990		

4IR4

TAB 2

Inspection Location Worksheets / Methods and Reasons for Component Selection

By: JCH 3/1/05 Reviewed T.M. 3/1/05

Note: Revised for VY and Industry Events and Operating Experience on 3/1105

Piping components are selected for inspection during the 2004 refueling oUlage based on the following groupings and/or criteria.

Lame Bore Piping

LA: Compol1ents selected from measured or apparent wear found in previous inspection results.

LB: Components ranked high for susceptibility from current CHECWORKS evaluation.

LC: Components identified by industry events/experience via the Nuclear Network or through the EPR] CHUG.

LD: Components selected to calibrate the CHECWORKS models.

LE: Components subjected to off normal flow conditions. Primarily isolated lines to the condenser in which leakage is indicated from the lurbine performance monitoring system. {through the Systems Engineering Group}_

LF: Engineering judgment / Other

LG: Piping identified from EMPAC Work Orders (malfunctioning equip., leaking valves, etc.)

Small Bore Piping

SA: Susceptible piping locations (groups of components) contained In the Small Bore Piping data base which haVe:; not received an initial inspection.

S8: Components selected trom measured or apparent wear found In previous inspection results.

SC: Components identified by industry events/experience via the Nuclear Network or through the EPRI CHUG.

SD: Components subjected to off normal llow conditions. Primarily isolated lines to the condenser In which leakage is Indicated from the turbine performance monitoring system. (through the Systems Engineering Group).

SE: Engineering Judgment! Other.

SG: Piping identified tram EMPAC Work Orders (malfunctioning equip., leaking valves, etc.)

Feedwater Heater Shells

No feedwater heater shell inspections will beperlormed during the 2005 RFO. All 10 of the leedwater heater shells have been replaced with FAC resistant materials.

LA: **Large** Bore Components selected(idenlified) from previous **Inspection** Results

From the 1995/1996/1998/1999/2001/2002/2004 Refueling Outage Inspections (Large Bore Piping) these components were identified as requiring future monitoring. The following components have either yet 10 be inspected as recommended, or the recommended inspection is in a future outage.

Inspect. No.	Loc. SK.	ComponenlID	Notes lComments I Conclusions
96-18 96-19	001	FD13EL05 FD13SP06	1996 Report: calculated time to tmin is 11.5 & t2 cycles based on a single measurement. The 2005 RFO is 6 cycles since the inspection. liT ins **ect elbow and downstream ipe** In **2008**
96-36	002	FD02SP05	1996 Report: calculated time to Tmin is 9.5 cycles based on a single measurement. The 2005 RFO is 6 cycles sinoe the inspection. **UT inspect elbow and downstream pipe** in **2007**
96-37	005	FD07SPOI	1996 Report: calculated time 10 Tmin is 9.6 cycles based on a single measurement. The 2005 RFO is 6 cycles since, the inspection. **UT inspect elhow and downstream ipe in 2007**
96·39	005	FD07SP02US	1996 Report: calculated time to Tmin is 10.5 cycles based on a single measurement. The 2005 RFO is 6 cycles since the inspection. **UT in ' lbow and downstream pipe in** 20.08
98-05 98-07	005	FD07EL06 FD07EL07	1998 Report: calculated time to Tmin is 7:5& 6.7cycles based on a single measurement. The 2005 RFO is 5 cycles since the inspection. Given no significant wear found in adjacent components (RSL =14.3 cycles on FD07SP07) defer inspection unlll RFO26. UT **inspect elbow FI 07EL07& and downstream pipe FD07SP08 in 2**
99-13	011	FD08EL04 FD08SP04	1999 Report: calculated time to Tmin is 7.9 & 12.5 cycles based on a single UT inspection. The 2005 RFO is 4 cycles since the inspection. **UT inspect elbow and downstream pipe in 20**
99·16	011	FD08SP05	1999 Report: calculated time to Tmin is 6.1 cycles based on a single measurement. The 2005 RFO is 4 cycles since the inspection. **UT inspect elbow and downstream pipe in 2007**
99-25 99-26	008	FD14EL03 FD14SP03	1999 recommendation to inspect pipe at upstream counterbore in 2004. Given thatthe only low readings were at the pipe counterbore and that 2004 RFO work included replacement of both No.1 feedwater heaters located under the elbow. **UT inspect elbow FD14EL03 & pipe FD14SP03 in the 2005 RFO.**
99·32 99-33	017	FD04TE01(plpe cap) CND-Noz32-A	1999 Report: calculated time to Tmin is 6.2 & 6.8 cycles based on a single measurement. The 2005 RFO is 4 cycles since the inspection. **UT insoect elbow and downstream olpe in** 2005
99-35 99'36	019	FD06TE01(pipe cap) CND·Noz32-C	199:9 Report: calculated lime to Tmin is 9.6 & 8.5 cycles based on a single measurement. The 2005 AFe> is 4 cycles since the inspection. **Ur inspect elbow and downstream pipe in 2005**
02·08 02·09	016	FD18EL01 FD18SP02US	2002 recommendation to lnspect the elbow in 2007 based on a single measurement. **Re-inspect** elbow **and downstream pipe** in **2007 (3 cycles** from **2002)·**
04·03	001	FD01TE05	2004 recommendation to inspect tee in 2008 based on the default wear rate of 0,005 inch/cycle, Re-Inspect upslream elbow **and** lee in **2008.**
04-06	002	FD02RD01	2004 recommendation to re-inspect in 2011 based on the default wear rate of 0,005 inch/cycle. Re-Inspect **reducer** with downstream **elbow and tee** In 2007.

.A: Large Bore Components selected(idenlifled) from previous Inspection Results **-continued**

Inspect. No.	Lac. SK.	Component 10	Notes /Comments / Conclusions
04-08	001	FOOZTE01	Z004 recommendation to inspect tee in 07 based on the default wear rate of 0.005 inch/cyde. Actual point to poini measurements from 1999 to 2004 indicate no wear. Given EPU operation, **re-inspect with u stream elbow** and reducer In **2007.**
04-09	001	FD03SP01	2004 recommendation to inspect pipe sectien in 2011 based en a single inspection and the default wear rale of 0.005 inch/cycle. **Re-inspect** in **2011.**
04-10	001	FDQ7SP02DS	2004 recommendation to inspect pipe section In 2008 based on a sin le ins ection. **Re-ins ect** with downslr.eam **elbow** In **2008.**
04-13	001	FD14EL03	2004 recommendation to inspect Row 13 pup piece to OS valve In 2008 is based on a sinole UT inspection. **Re-inspect** In 2008.
04-23	001	MSD9TE01 to MSD9TE08	2004 recommendation to inspect pipe section in 2010 due to localized wear directl under 2 lines. **Re-inspect** In 2010.
04-23	001	MSD9EL05	2004 recommendation to inspect pipe section in 2010 base on a single inspection. **Re-inspect** in **2010.**

Turbin'e Cross-around Piping:

Previous Internal Visual UT & Repair History:

[redacted] Internal Vi[redacted] V [redacted] Internal Thickness UT, [redacted] irs Performed R

[redacted]	[redacted]	Replaced						RFO21 F1999	RFO22 S2001	RF023 F2002	S2004 RFO24
36"-A	GE*	1983									V
36"-B	GE**	1 81	V					V			V
[redacted]											
36"-C	GE**	1981									
36"-D	GE**	19		V	V		V				V
30"-A	P-22*	965	V		V		V				
30"-B	C.S.	Original	V/UT/R	V/UT/ R	WUT/ R	V/UT	V	V		V	
30"-C	P-22*	1993	V/UT/R								V

NOTE; Reference Dwg. No. **5920-6841** Sh. 1 of 2 needs to be **updated** with oorreotInformation. This will be **performed during** the EPU **design** ohange effort.

The HP turbine rotor was replaced in 2004. Internal visual inspection oj all four 36"dlameter lines was performed. An internal visual inspection of the 30"C line (firsl inspection since the 1993 replacement) and the 30" D line was performed.

2005 RFO based on increased flows and the possibility of different flow regimes in both the 36 & 30 inch piping, perform a visual Inspection. LP tUfbine work in 2005 RFO may provide opportunity lor access to the 30" lines. As a minimum inspect (2) 36 inch lines and the carbon steel 30" B line.

LB: Large Bore Components Ranked High for Susceptibility from CHECWORKS Evaluation

The current CHECWORKS wear rafe calculations contain inspection data up to the 1999 RFO and wear rate predictions are current to the 2001 RFO. The 2001 and 2002 RFO inspection data has been entered into the CHECWGRKS database. However, updated wear rate calculations are not complete, and won't be in time to support the schedule date for issuing lhe inspection scope for the 2005 outage. Basedon a review ot *the* 2001 and 2002 RFO inspection data for components onlhe Feedwater, Condensate, and Heater Drain Systems, the CHECWORKS models still appear to over-predict actual wear. Nothing new or unanticipated was observed in either 2002 or 2004.

Feedwater System

Listed below are components which meet the following criteria:

a) negative time to Tmin from the predictive CHECWORKS runs which include Inspection data up to the 1999 RFO.
b) n'o inspections have been performed on these components or the corresponding components in a parallal train since the 1999 RFO.

Component ID	Location Sketch	Location	Notes
F 107EL05 FD07TE01 FD07EL11	005 006	TB FPR Elev. 241 r.a Heater Bay Elevs 228 & 248	Com onents on other train were ins ected. Components on other train were inspected In 1998. Results indiGate minimal wear. After updatlng the CHECWORKs model with newer data, assess need for additional inspections in 2007 RFO.
FD07EL12	006	T.B Heater Bay Elev. 248	Feedwater heater replacement occurred in 2004 RFO. Informal visual inspections of intemals and cut pipa profile indicated a stable red oxide and no distinguishable wear pattern.
FD08TE01 FD08EL07	012	T.B Heater Bay Elevs 228 & 248	Intermet iate components FD08EL06 &, FD08SP06 were inspected In 1998. Results indicate minimal wear. After updating CHECWORKs model with newer, data, assess need for inspecting components on the train vs. the
FD08EL08	012	T.B Heater Bay Elev. 248	Feedwater heater replacement occurred in 2004 RFO. Informal visual inspections 01 internals and cut pipe profile indicated a stable red oxide and no distinguishable wear pattern.
FD15EL08	013	RX Steam Tunnel El. 266	Internal visual of elbow performed in 1996 during check vaivereplacement, no indication of wall loss at that time. Corresponding component on line 16"- FDW-14 was inspected in RF024. After updating CHECWORKs model with newer data, assess need for inspecting this component in 2007 RFO.

LB: large Bore Components Ranked High for Susceptibility Irom CHECWORKS Evaluation - continued

Condensate System

Only one component was identified as having a negative time to Tmin. This was CD30TE02DS, the downstream side of a 24x24x20 tee on the condensate header in the teed pump room. The CHECWORK$ prediction tor the downstream side of the tee has a small negative hrs relative to the remainder ot the components in the system and relative to the upstream side of the same tee. Other tees on the same header have been previously inspected and show no significant wear. The CHECWORKS model includes UT data up to the 1999 RFO. The inspections on this system performed in 2001 indicate minimal wear. **Components CD30TE02** and **CD30SP04 were inspected** iii 2004. This dala along with the 2001 inspection data will be input to CHECWORKS to better calibrate the model.

Moisture Separator Drains & Heater Drain System

No components identified as having negative times to Tmin. No components wete selected icr inspection in 2001, 2002, or 2004 based on high susceptibility. However future operation under HWC will change dissoived oxygen in system. A separate evaluation has been performed and components were selected for inspection in 2002. See Section LD below.

Extraction Steam System

Three components on this system with negative time to code min, wall: The piping is Chrome-Moiy. ES4ATE01 & ES4ATE02, 30inch diameter tees inside the condenser have negative prediction (-3426Hrs.) for time to min wall. The negative times to tmin may be conservative based on the modeling techniques used. Relinement of the model of this system is in progress. The negative time to tmin is most likely a function of lack of inspection data vs, actual wear. Due to external lagging on tills piping and the location inside the condenser, no components are selected for external UT inspection in 2004 based on high susceptibility. However, an opportunity to perform an Internal visual inspection of all the Extraction Steam lines Inside the condenser during planed LP turbine work in !lie 2005 RFO may present itself. See Section LF below.

Note the short section of straight pipe on line 12"-ES-1A at the connection to the 36 inch A cross around is assumed to beA106 Gr. B carbon steel is not modeled in CHECWORKS. This componenlwas inspected in 2004 by external UT and an internal visual inspection from the 36" cross around line.-

LC: Large Bore Ccmponents Identified by Industry Events/Experience.

Review of FAC related Large Bore Operating Experience (OE) and/or piping failures reported since April 2003

Date	Plant – Type	Deseri tion & Recommended Actions at VY
8/9/2004	Mihama3 - PWR	OE19368/OE18895: Rupture of Condensate line downstream of restriction orifice. PWR system highly susceptible to single phase FAC due to low DO. Similar region of system as 1986 Surry evant (5 fatalities). Based on info gathered by INPO/CHUGfFACnet the location was omitted from previous inspections due to clerical error, once discovered management missed opportunllyto inspect and deferred inspection until 9/04. Too late. Lesson: make sure all highly susceptible locations get inspected. PWR Condensate/feedwater piping is much more susceptible to single phase FAC than BWR with 02 injection. Given that, previous inspection hlslory, and condensate CHECWORKS modeling; inspect piping bs of all flow orifioes in the higher temperature condensate system that have not been previously inspected in RFO25. **Inspect CD30FE01 / CD30EL11 / CD30SP02 in RFO25 (re-peat inspection** from **1989).** Aiso, **inspect CD31FE01 / CD31EL04 / CD30 P04 in RFO25 (new inspection).**
10117103	Duane Arnold - BWR	OE17300: Through wall leak In 4" diameter chrome-moly Heater Drain System bypass line to the condenser. The line was a temporary installation due to delayed FWD heater installation. The cause of the leak appears to be droplet impingement erosion due to use of a bypass control valve. The equivalent lines at VY are the Heater Drain bypass lines to the condenser downstream of the high level control valves. These line have RTD's attached to monitor leakage into the condenser (TPM system). Some inspections have been performed on these lines. Consider for re-inspection only if TPM indicates leakage by the normally closed valves.
9/24/03	South Texas Project - PWR	OE17378: Pitting & internal wear found on discharge piping of Condensate Polishing System. Pipe is carbon steel, low water temperature (90 to 130F), neutral pH, and velocity of 12.2 Ft./sec Tortuous flow path and control valves, wear may be impingement. PWR system Low dissolved oxygen. Equivalent system at VY is Condensate Demineralizer System which is low temp and screens per NSAC-202L as not s le to FAC on temperat ing. No OE on BWR systems.
11/07103	Braidwood 2-PWR	OE17464: Wall thinning found on FDW pump discharge nozzles and ding into downstream pipes on all 3 FDW pumps. Material has high chromium content. PWR feedwater system chemistry has low D.O. therefore more susceptible to wall loss due to single phase FAC than BWR feedwater piping. At VY all three feedwater pump discharge nozzles and downstream piping have multiple inspection data. No further actions are anticipated from this OE.
10/31/03	Clinton _BWR	OE17412 / OE18478: Through-wall leaks in 2A1 B heater vent lines to the condenser (lager bore lines assumed given description of backing rings in piping). Appareril cause attributed to steam jet impingement from wei steam. Equivalent line at VY is common 4 inch feedwater heater vent line 101 No.4 FDW heaters. This line is included in the SSB database since It connects to (2) 2-1/2" lines. Inspection priority will be determined in the small bore ranking and prioritization.
11119/03	Hope Creek – BWR	OE17700; Pinhole leak and wall thinning in 8" in carbon steel Extraction Steam suppiy iine to Steam Seal Evaporator. Location of wear is downstream of pressure safety valves. Apparent Cause of leak & wear is due to liqUid droplet impingement due to high flows from failure 01 pressure safety relief valves. No equivalent configuration at VY.
1/24/04	LaSalle 1 - BWR	*OE171991* OE18381: Tough·waii hOles in extraction steam piping Inside condenser. Location of holes at inlet nozzles to No.2 FDW heaters located In the neck oj the condensers (2nd lowest stage). All 12 nozzle are C,S. with A335-P11 upstream piping. VY has only the No.5 FDW heaters in the neck of the condenser. The No. 5 FDW heaters were replaced with Chromo-moly shells. ES piping Is A335-P11 or e uivalent which is FAC resistant. No further actions are anticinated from this OE,

LC: Large Bore Components Identified by Industry Events/Experience - continued

Date	Plant -- T e	Descn tion & Recommended AClions at VY
2/17/04	Peach Bottom 2 BWR	OE18637: Online leak in 10 inch main steam drainlille header to the condenser. Hole was located directly below the connection of 1" main steam lead drain. The header was replaced with 1-1/4 Chrome material approx. 5 years before the leak. Also, ROs in steam drains were modified. The cause was attributed to stearn impingement Additional information to follow after next RFO. The oniy large bore drain COllector at VY is the 8 inch diameter low point drain header, line S"MSD-9. Flow Is through steam traps and ICVs vs. a continuous flow through a restriction orifice. This line is now part of the AST ALT boundary. Inspections of the entire bottom 01 this header were performed during RF024 with recommendations lor repeat inspections In 2010.
8/26/04	PalO Verde 3-PWR	OE20386: Through wall leak found on a 10 Inch flashing tee cap on the IP feedwater heater drains. Problems with inspection of flashing tees in program. Only 14 QUi 011.53 susceptible locations have UT data at Palo Verde 1,2,3. There are no flashing tees 0.8. of LCVs on the heater drain system at VY. The only flashing tees al VY are located on the FWD pump min flow lines at the condenser. Inspection 01 all 3 lines 6"FDW-4, 6"FDW-5, and 6"FDW-6 is scheduled for RFO25.
9/24/04	Palisades- PWR	OE19494: Wall thinning In carbon steel Extraction Steam piping. Increased localized wear downstream of Bleeder trip valve. Equivalent piping at VY Is Extraction Steam piping downstream of the reverse current valves. ES piping at VY is A335-P11 which is FAC resistant. No further action is rei uired for this OE.
9/18/04	Catawaba 2 -- PWR	OE19350: Wall thinning found four different areas on FDW piping. Two areas are not considered specific to Catawba: 1)Area where main feedwater bypass reg valves reenters the feedwater header and 2) downstream 01 the main feedwater reg valves. PWR feedwater system chemistry has low D.O. therefore more susceptible to wall loss due 10 single phase FAC than BWR feedwater piping. At VY area 1) doses not exist (bypass lines dump to the condenser) 2) Inspections have been performed upstream and downstream of both main feed reg. valves. Inspection of FD08RD03 and FD03SP02 are scheduled for RFO25. No further actions are anticipated from this OE.
11/3/04	Duane Arnold - BWR	OE1 01: Wall thinning downstream of Torus Cooling Test Return Header Isolation Valve. Apparent cause was cavitation erosion due to throttling in valve during HPCI & RCIC testing. At VY, the equivalent valVes are V10-34A & 34B. The degree of cavitation present Is dependent of the system design and may vary from plant to plant. Previous UT inspections were performed on valve bodies and downstream reducers in early 90s. No significant wear was lound. Consider inspection of downstream piping In RF026 if additional OE warraflts It.
216105	Calvert Cliffs 1 - PWR	OE2Qt27: Through-wall leak in 6 inch steam *vent* header for MSR rain tank. VY does not have same configuration. NO Moisture Separator Re-heaters
2117/05	Clinton -BWR	OE20246: Catastrophic failure 01 turbine extraction steam line bellows inside condenser. Found through-wall holes ES piping OS 01 bellows due 10 FAC. Apparent cause was attributed to the steam jet from the holes inducing vibration of the expansion joint that led to high cycle latlgue lailure. At VY extraotion steam piping inside the condenser is A335·P1 1 or equivalent which is FAC resistant. No further actions are anticipated from this OE.
5/9/01	Grand Gulf - BWR	Pin Hole Leak In 4 inch carbon steel elbOW in RHR min flow line. System has low use at VY «2% of time). (Perry also lound thinning at elbow per C.Burton at CHUG meeting.) A review of VY drawings VYI·RHR·Pari 14 Sht.il1 and VYI·RHR Part 15 Sht.1It show elbows downstream of restriction orifices. Previous VY Inspections downstream 01 orilices on HPCIfand CS systems found no problems. Keep OE listed for future conslderali.oo.

LC: **Large Bore Components Identified** by Industry Events/Experience· c,onllnued

Date	Planl-T e	Descri ion & Recommended Actions at VY
9124102	IP2 -PWR	Pin hole leak on 26 ½" cross-under piping (HP 10 MSR) in vicinity of dog bones at expansion joint under location of weld overlay localized wear under/around a previous weld overlay repair. VY has solid piping (no expansioo joints). Visual Inspections of 30' B CAR carbon steel piping will be performed in 2005.
1/15/02 CHUG Meeting	Surry 1-PWR	Leak in 8 inch Condenser drain header for 3rd/4th pl. FDW Heater vents. Also thinning in Gland Steam Piping inside the condenser and lhe12" Condenser Drain header from MS Drain trap lines. The only large bore drain collector at VY is the 8 inch diameter low point drain header, line 8"MSD-9. This line is now part of the AST ALT boundary. Inspections 01 selected components on this line were pertoimed during RF024 with recommendations for repeat inspections in 2010 (Section LB above). Given this line is part of the ALT Boundary inspect approx. 2 fl. long section at condenser wall during RFO26 (2007) or RF027 (2008).

LD: **Large Bore** Components **Selected** to Calibrale CHECWORKS

The CHECWORKS modeis have been upgraded 10 inciude the 96, 98, & 99 RFO inspection data. The 2001 and 2002 inspection data has been loaded however wear rate analyses have not been completed allhis time.

Condensate:

In 2001 components 011 the higher lemperature end of the Conden.sale System were Inspected to calibrate !tie CHECWORKS models. The inspection data indicate minimal wear and should reinloroe the assessment of low wear in the Condensate System. Additional components selected for inspection in 2004 in Section LB above will be used 10 calibrate the CHECWORKS model.

Heater Drains/ Moisture Separator Drains:

Prior to the 2002 RFO there was limited inspection data for the Heater Drain system. The current CHECWORKS models (Pass 1 and some Pass 2) indicate low wear rates. During 2002 a number 01 new inspections were performed on the carbon steel piping upstream of the level control valves (LCV) to obtain it baseline prior to operation on hydrogen water chemistry. Piping down slream 01 the LCVs is FAC resistant material except lor inlet to No.5 Feedwater heaters. No additional components on the Healer Drain system will be inspected in 2005.

Feedwater:

No inspeotions on line 18"·FDW·'2 have been inspecled: **Inspect** FD12EL06 and **FD12SP08US** in 2005

Main.Steam

Only 2 components In the Main Sleam system on line 18'MS-7A in lhe drywell have been inspectedl0 date. **Inspect** MS1DEL07 and MS1DSP13US In **2005.** (Nole this also addresses a license renewal consideration tor monitoring of Main Steam Piping).

LE: Large BOTe Components subjected to off normal flow conditions identified by turbine performance mpnitpring system (Systems Engineering Group).

The Systems Engineering Production Variance Reports for 2003 listed the "B" and "C" feedwater pump min flow valves as leaking into the condenser. There are sections on carbon steel piping at lhe connection to the condenser on all three lines. As /i minimum inspect the "B" and "C" lines In 2005.

There have been concems with cavitation at condensate min llow valve FCV-4. An internal inspection 01 the valve performed in RFO 24 showed some damage to the valve internals. However, due 10 a leaking isolation valve the connecting piping was 110000d and an internal visual inspection coutd not be performed. UT inspect the upstream and downstream piping during RFO25. The valVe is operated during outages and startup at relatively low temperatures for FAC to occur. The piping is un-insulated and close to the 1l00r. No insulation removal or scalolding will be required.

Since startUp from 2004 (RF024), no other leaking valves or steam traps have been identilled (to date) using lhe Turbine Performance Monitoring {rPM} system. However, if new data Indicates leaking valves then, additions to the outage scope may be required.

LF: **Engineering Judgment / Other**

Nine ASME Soelion XI Class 1 Category 8-J welds are to be inspected by the FAC program per Code Case N-560 in lieu 01 a $ection XI volumetric weld inspection. The VY ISI Program Interval 4 schedule for inspection of these welds Is as tallows:

Refueling Outage	Section XI ISI Program Weld 10	Description	FAC Program Components
Spring 2004 (RFO24) Interval 4 Period 1, Outage 1.	FW19-F3B FW19-F3C FW19-F4 FW21-F1	upstream pipe to tee tee to reducer reducer to pipe tee to pipe	"A" Feedwater on Sketch 010 FD19TE01 FD19RD01 FD19SP04 FD21SP01
Fall 2011 (RF029) Interval 4 Period 3, OUlage 6,	FW18-3A FW20·3A FW20-F1 FW20·F1B FW18·F4	upstream pipe to tee tee to reducer reducer I0 pipe horizontal pipe to pipe tee to bibe	"8" Feedwater on Sketch 016 F018TE01 FD20RD01 FD20SP01 FD18SP04

Continued

LF: Engineering JUdgment! Other --**continued**

Extended Power Uprate **(EPU)**

Feedwater system:

EPU evaluation tor Feedwater System: The primary focus of work to date (for PUSAR and RAIs) was on velocity changes given only slight inoreases in temps and no chemistry changes. With all 3 FOW pumps running the 16 inch diameter lines to lhe 24 inch FDW header have approx. [1.2(213) = 0.80120% reduction in velocity. Velocities In the remainder 0l the sysfem Increase approx. 20%. The highest velocities are at the 10 Inch reducers upstream and downstream of ihe FOW REG valves. The expander and downstream piping have mUlllple inspection data with FD07RD03/FD07SP03 last inspected in 2001 and FD08RD03/FD08SP02 last inspected in 1999. **Both of these** se:gmerits **should** be **re- inspected** after **some** lime of **operation** at EPU flows. Assuming EPU **starting early** in **2006, inspect components FD08RD03** & FD08$P02 In **2005** to obtain an up to date **pre-EPU measurement. Inspect** FD07RD031 **FD07SP03** In 2007 for a post EPU **measurement.**

Condensate System:

Given the 8104 Mihama event: consider addiUonal component in lhe condensate system for inspection : downstream of flow orifices & venturies:

FE-102-4 and downstream pipe on 24"C-8 venturi type (TB condensate pump 100m overhead) Given low operating temperatures and upstream of oxygen injection point, **scope** oui and evaluate for **inspection In** RFb261n 2007
FE-52-1A to FE-52.1E on Condensate De-mlneralizer System (Restriction Orifices). Given low operating temperatures and upstream 01 oxygen injection point, **scope out** and **evaluate** *tor* **inspection in RFO26** In 2007
FE-102-7and downstream pipe on 14"C-21 venturi type TB Heater Bay E1237.5 Given low operating temperatures and used for start-up, scope **out and evaluate for inspection in** RF026in **2007**
FE-102-2A on 20"C-30, located in the TB FPR above FDW pump 1A (venturi type) Previously inspected in 1989 **Re-Inspect FE and downstream piping in RFO25**
FE-102-2B on 20"C-31, located in the TB FPR above FDW pump 1B (venturi type) No previous inspection data. **Inspect FE and downstream piping** In **RFO25**
FE-102-2C on 20"C-32, located in the TB FPR above FDW pump 1C (venturi type) Previously inspected in 2001

All Extracflon Sleam piping is A335-P11, a. 1-114 chrome material, except for a short carbon steel stub piece in line 12"-ES-1A af lhe connection to the 36" A cross around line. An inlernal visual inspection ollhis stub piece was performed with the cross around inspection in RF024. Also an UT inspection of ES1ASP01 was performed in RF024.

Extraction Steam piping in the condenser has external lagging which requires significant eftort lor removal when performing external UT inspections (piUS there are significant staging costs). The piping is A335-P11. However an opportunity fo perform anlnternai visual inspecticn of all the Extraction Sleam lines inside the condenser during planed LP turbine work in the 2005 RFO may present itself.

LG: Piping Identilled from EMPAC Work Orders (malfunctioning equip., leaking valves, etc.)

Word searches of open work orders on EMPAC were performed lor Ihe following keywords: trap, leak, valve, replace, repair, erosion, corrosion, sleam, FAC, wear, hole, drain, and inspect. No previously unidentified components or piping were identified as requiring monitoring during the Fall 2005 RFO.

Note: the internal baffle piate in Condenser B lor the AOG train tank return line to Ihe condenser is 10 be replaced in RFO 25 (ER 04-1454/ ER 05-2321ER 05-0274). Erosion on baffle plale is from condenser side (not piping side).

Internal visual inspection 01 LCV-103-3A-2 during RFO 24 indicated some type of casting flaw. The System Engineer suspects possible leaking by the normally closed valve. The downstream piping was last inspected in 1990. The line typically has no flow. Re-evaluate using the Thermai Performance Monitoring System Data and cOllsider inspection 01 downstream piping in RF026.

Through wall leak in the steam seal header supply line ISSH4 discovered on 9/24/04 (CR-VTY-2004-02985). A temporary leak enclosure was installed and a planned permanent repair is scheduled for RF025. The leaks are on the bottom of un-insulated piping upstream of tha gland seal. Field Inspection of the leak location shows that the piping at the leak sloping down 10 the gland seal, not sloping up to the seal a shown on the design drawings. UT data on the top of the piping near the leak shows tull wall thickness. At this time, the exact mechanism which caused the leak is nol known. Additional inspections to determine the extent ot condition on the 3 other gland seal steam supply lines are required

Inspect the 90 **degree elbow** andapprOx. 2 ft. of **downstream piping on lines** 1SSH3; 1SSH4, 1**SSH5, and 1SSH6 during RFO 25. Also based** on Industry OE and **similar** piping **geometry, inspect** 2 of the **SPE lines (1SPE3 and 1SPE5 during RFO 25.**

Small Bore Piping

SA: Susceptible piping locatlons (groups of components) contained in the Small Bore Piping data base **which** have nol **received** an **Initial inspection.**

Locations on the continuous FDW heater vents to the condenser on the No.3 heaters were inspected in 2002. The continuous vents on the No.4 heater were installed new in 1995. The start up vents operate less than 2% of operating time. No wearwss found in previous inspections on Heater Vent piping from the No.1 & 2 heaters. Given that and the lower pressure in the No.4, shells a complete Inspection of the remainder oi the No.4 heater vent piping can be deferred. The existing small bore date base and the piping susceptibility analysis is under revision. No additional components from Revision 1 of the data base will be inspected.

SB: Components selected from **measured** or apparent wear found **in** previous **inspection** results.

Small Bore Point No. 20. 2-1/2" MSD-6 @ connection to condenser A at Nozzle 33 (Inspection No. 96-8B01 identified a low reading,at weld on stub to condenser). Upstream valves are normally closed. TPM system does not indicate any abnormal flow. **Inspect** this piping In **RFO** 26

A through wall leak in the turbine bypass valve chest 1st sealleak-olf line form the No.1 bypass vales occurred in 2003. (VY Event Report 2003-044). A temporary leak enclosure was Installed (T.M.2003-002) to contain the leak}. W:O. 03-0364 was written to inspect/repair/replace/line. A localized like-for-like (carbon steel) replacement of the leak location was performed in RFO 24. Additional inspections on this line identified localized wall loss and one additional like-for-like repair was performed. EngiMering Request ER 04-0963 was written to completely replace this piping with chrome-moly piping. (Dresden has already done this). The **replacement (ER** 04-0964) **is** currenlly **scheduled for RFO 25. If** this activity gets **"de-scoped" then, additional inspections will** be **required to insure the piping** is acceptable for **continued operation.**

Small Bore Piping

SC: Components identlfled by Industry events/experience via the Nuclear Network or through the EPRI CHUG.

Date	Plant – Type	Description & Recommended Actions at VY
11/7/2003	Limerick 1, BWR	01217818: Through wall leak In 1 inch drain line back to condenser oft 12S piping at the connection to the large bore line. Normaliyno flow in line due to N.C. valve. Piping downstream of valves to wndenser on all 3 lines was scheduled for replacement. Location US of valve was thought not to be susceptible. 12$ piping at VY is FAC resistant A335-P11 with no drains back to the condenser. Lesson from this event is any carbon steel line In a wet steam system is susceptible & should be monitored. Also full line replacement insures all susceptible piping is replaced.
1116/04	Clinton BWR	01217654: Potential tend tor adverse equipment condition downstream of orifices. (Ref. Previous experience a Clinton with CRDpump min flow ROs) Insoect CRD oumD min flow orifices also piping DS 01 RO-64-2 in RFO25
12/06/04	V.C. Summer-PWR	OE19798: Complete failure ola 1 inch ES line at the location of a previously Installed Fermanite clamp repair. Previous leak at weld installed in MAY 2004. See presentation at January 2005 CHUG meeting. (They did not do UT on the pipe to assure structural integrity prior to installing the clamp.)
311105	McGui,e 2-PWR	Though-wall leak in a 2 inch carbon steel vent line on theMSR heating steam vent line. Caused by FAC when flashing occurred upstream of RO (design location) No.MSRS or equivalent location at VY.
4/29/99	Darlington 1 - PHWR	Severed line at steam trap discharge pipe at threaded connection. Equivalent to HHS system at VY. (INPO Event 931-990429-1) Threaded connections typically on condensate side of HHS piping. Lower energy/consequence of leak. Include HHSpIpingin FAC Susceptibility Review, and in the Small Bore Database. Include ranking and consequences of failure.
6/14/99	Datljrigtoli 2 - PHWR	Leak on steam trap discharge pipe at threaded connection. Equivalent to HHS system at VY. INPO Event 932-990614-1) Same as above.
9/1101	Peach Bottom 3 -BWR	(From 1114102 CHUG Meeting), leak on 1 inch Sch. 80 line from in Off Gas Re-combiner pre-heater drain line to condenser. Perform additional review of AOG steam supply system and incorporate into FAC Susceptibility Review. Update small bore database to include rankin and cons uences ot failure.
1/15//02 CHUG Mtg.	Hatch1f2 -BWR	Condenser in leakage due to through wall erosion (external) of 1-1/2 inch "slop" drains lines inside the condenser. Lines In each unit were cut and capped similar events at Byron Unit 1 (OE 12609) and Columbia (OE12145). Limerick & Dresden. VY slop drain lines Inside condenser were walked down during RF024. Some external erosion on oi ina and SUODOrts was found.
1/15102 CHUG Mig.	Catawba 2 - PWR	Leak in HP lurbine pocket shell drain 1 inch dia. OEM showed pipe as P-11. However, A-106 Gr. B was installed. Inspections were be performed on lhis line In 2004 to base line condition prior to HP turbine rotor re lacement.
1/15/02 CHUG Mtg.	Dresden 2 BWR	Thinning found in Bypass valve leak-off line to the 7 stage extraction steam line. Line is 2" Sch. 80, GE B4A39B. Lowest reading was 0.070" found using Phosphor Plate radiog'aphy. Line was replaced with A335 P-11. Same line as 2003 VY through wall ieak. Partial CS replacement was performed In RFO24. Pi ,inQ Is scheduled to be replaced with A335-P11 In RFO25 (ER 04-0965).

Small Bore Piping

SD: Components subjected to off normal flow conditions, as Indicated **from the** turbine performance monitoring system (Systems Engineering Group).

No small bore lines have been identified by Systems Engineering on or bejore 3/1 *105*.

SE: Engineering judgment

Look at piping DS at orifices based on BWR OE

Condensate: Given the *8104* Mihama event: consider additional component In the condensale system tor inspection downstream of floW orifices & venturies.

FE-I02-6 and downstream pipe on **21/2"C-43** venlurllype (TB healer bay elev. 230+/- Given low operating temperatures and upstream of oxygen injection point, **scope** oul and evaluate for **inspection in R26 in 2007**

SG: **Piping** Identffled from EMPAC **Work** Orders (malfunctioning equip., leaking **valves, etc.**)

See LG above, The EMPAC search performed in LG above is applicable 10 both Large and Smaii components.

MEMORANDUM

Vermont Yankee Design Engineering

TAB 3

To S.D.Goodwin Date May 5, 2005 *

From James Fitzpatrick File # VYM Z004!OO7a

Subject Piping FAC Inspection Scope for the 2005 Relueiing Outage (Revision 1a)

REFERENCES

(a) PP 7028 Piping Flow Acceleraled Corrosion Inspection Program, LPG 1, *12/6/2001.*
(b) V.Y. Piping F.A.C. Inspection Program -1996 Relueling Outage Inspection Report, March 23,1999,
(cl V.Y. Piping F.A.C. Inspection Program - 1998 Refueling Outage Inspection Report, April 2,1999.
(d) V.Y. Piping FAG, Inspection Program -1999 Refueling Outage Inspection Reporl, February 11, 2000,
(e) V.Y. Piping FAG. Inspection Program - 2001 Refueling Outage Inspection Report, August 11,2001.
(f) V.Y. P1ping FAG. Inspection Program - 2002 Refueling Outage Inspeotion Report, January 20, 2003.
(g) V.Y. Piping FAC. Inspection Program· 2004 Refueling Outage Inspection Report, February 15, 2005

(h) DiSCUSSION

Altached please lind the Piping FAC Inspeotion Soope for the 2005 Refueling Outage. The scope includes locations identified using: previous inspeotion resuits, theCHECWORKS models, industry *and* plant operating experience, input from the Turbine Performance Monitoring System, the CHECWORKS study performed to postulate affects 01 Hydrogen Water Chemistry operation *on* FAC wear rates in plant piping, and engineering jUdgment.

The planned 2005 RFO inspection scope consists 0137 large bore components at 16 locations, internal inspection 01 three legs 01 the turbine cross around piping, and 5 sections 01 small bore piping. Also, any industry or plant events that occur in the interim may necessitate an increase in the planned scope.

I will be available to support planning and inspeotions as necessary. If you have any questions or need additional information please contact me.

(Revision 1 identifies Small Bore Inspections due to IndUstry OEI.
'(Revision 1a adds component Nos. to SSH & SPE piping & oorrects inor typos in Attaohment)

am s . Fitzpatrick
D . n Engineering
Mechanioal/Structural Group

ATTACHMENT: 2005 RFO FAC Inspection Scope *3111/05* (3 Pgs) Revlsed **5/5/05**

CC L.Lukens Code Programs Supervisor
OoKlng (ISI)
T.M.OConnor (Design Engineering)
Nell Fales (Systems Engineering)

LARGE BORE PIPING: External UT Inspections

Point No.	Component ID	location Sketch	location	Previous Inspections	Reason / Comments / Notes
2005-01	FD14EL03	008	T.B. Htr. Ba Elev.267.	1999	1999 recommendation for repeat inspection.
2005-02	FD14SP03US	008	" " "	1999	
2005-03	FD04RD01	017	T.B. Htr. Ba Elev.248.	1999	Inspect per 1999 calculated wear rate.
2005-04	FD04TE01	017	" " "	1999	
2005-05	Cond Noz32A	017	" " "	1999	
2005-06	FD05RD01	018	T.B. Htr. Ba Elev.245.	1993	TPM system indicated leakage by normally closed valve.
2005-07	FD05TE01	018	" " "	1993	
2005-08	Cond Noz 32B	018	" " "	1993	
[redacted]					
2005-11	Cond Noz32C	019	" " "	1999	closed valve.
2005-12	FD08RD03	011	T.B. FPR Elev.231	1999	EPU flows increase
2005-13	FD08SP02	011	" " "	1999	
2005-14	FD12EL06	007	T.B. Htr. Ba Elev.264.	NO	Checworks Model Calibration. Asbestos removal required.
2005-15	FD12SP08US	007	" " "	NO	
2005-16	CD30FE01	037	T.B. FPR Elev.241	1989	FE-102-2A (Mihama Event)
2005-17	CD30EL11	037	above "A" FDW pump	1989	
2005-18	CD30SP12	037		1989	

POint No.	Component ID	Location Sketoh	Location	Previous Inspections	Reason / Comments / Notes
2005-19	CD31 FE01	038	T.B. FPA Elev. 241	NO	FE-102-2B (Mlhama Event)
2005-20	CD31 EL04	038	above "B" FDW pump	NO	Asbestos removal required.
2005-21	CD31SP04	038		NO	
2005-22	CD21RD02	040	T.B. Htr. Ba Elev.230.	NO	Inspect piping upstream and downstream of
2005-23	CD21RD01	040	" " "	NO	FCV-102-4 (piping is not insulated).
2005-24	1SSH3EL05	•	Turbine deck at packing	NO	LP Turbine Steam Seal supply lines due to
2005-25	1SSH3SP06US	•	3 Htr. Bay Elev. 254.		through wall leak at elbow on nne 1SSH4.
2005-26	1SSH4EL01	*	Turbine deck at packing	NO	
2005-27	1SSH4SP02US	*	4 Htr. Bay Elev, 254.		'See markup 01 Dwg. 5920-1239
2005-28	1SSH5EL01	•	Turbine deck al packing	NO	
2005-29	1SSH5SP02US	•	5 Htr. Bav Elev. 254.		
2005-30	1SSH6EL06	"	Turbine deck at packing	NO	
2005-31	1SSH6SP08US	"	6 Htr. Bav Elev. 254.		
2005-32	2SPE3EL01	•	Turbine deck at packing	NO	IP Turbine SteamPacking Exhaust at packing 3
2005-33	2SPE3SP01 US	•	3 Hlr. Bay Elev. 254.		and 5 due 10 lhrough wall leak at elbow on line
2005-34	2SPE5EL01	*	Turbine deck at packing	NO	1SSH4.
2005-35	2SPE5SP01 US	*	5 Htr. Bay Elev. 254.		'See Markuo of Dwn. 5920-1239
2005-36	MS1DEIO7	080	AX Stm Tunnel Elev.	NO	EPU and LR data required for Main Steam lines
2005-37	MS1DSP13US	080	25410260	NO	

LARGE BORE UT NOTES,

1. Coordinate minimum extent of insulation to be removed with J.Fitzpatrick or T.M. O'Connorirom DE-MIS.
2. A "No" in the previous inspeotlon oolumn indlcates asbestos abatement may be required.

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LARGE BORE PIPING: Internal Visual Inspections (With supplemental UT as required

In. etion Point No.	Deserl ion
2005-38	36" **CAR** A (36 inch diameter Line A Turbine Cross Around under HP turbine)
2005-39	36" CAR C (36 inch diameter Line C Turbine Cross Around under HP turbine)
2005-40	30"CAR B 30 inch diameter Line B Turbine Cross Around upper east side of heater ba

SMALL BORE PIPING

Small Bore inspection Number	S.B. Data Base No.	System	Description	Location	Drawings	Reason IComments
05-SB01	11	Condensate	1" piping OS of R.O. 64·2	T.R Heater Bay	G191157Sht,1 5920- FSI -17	InduslryOE17654
05-SB02	128	CRD	1" Piping D.S. 01 R.O.-3-24A	Rx. SW Elev. 232,5 P38-1A	G191170IG191212 IG191215	Industry OE17654
05-S803	12	CRD	1" Piping D.S. of R.O,-3-25A	Rx. SW Elev. 232.5 P38-1A	G191170 1G191212 IG191215	IndustryOE17654
05-S804	130	CRD	1" Piping D.S. of R,O,-3·24B	Rx. SW Eisv. 232.5 P38-1B	*G1911701* G191212 *IG191215*	Industry OE17654
05-8805	131	CRD	1" Piping D.S. of R.O.-3-25B	Rx. 8W Elev. 232.5 P38·1B	G191170 1G191212 IG191215	IndustryOE17654

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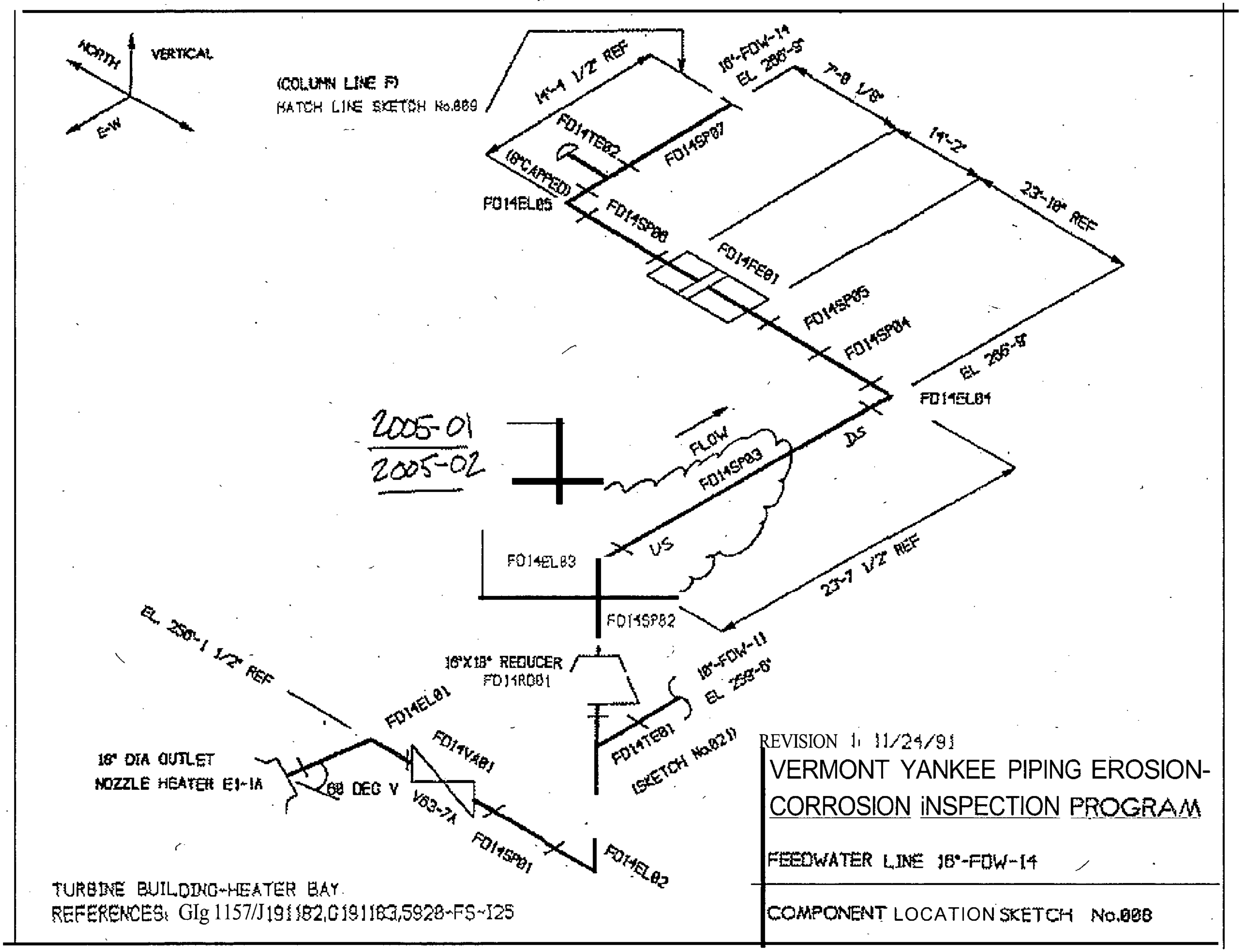
NORTH
VERTICAL
E-W
(COLUMN LINE F)
MATCH LINE SKETCH No.009
14'-4 1/2" REF
16"-FDW-14
EL 286'-5"
7'-8 1/8"
14'-2"
23'-10" REF
FD14TE02
(16"CAPPED)
FD14SP07
FD14EL05
FD14SP06
FD14FE01
FD14SP05
FD14SP04
EL 286'-5"
FD14EL04
2005-01
2005-02
FLOW
FD14SP03
DS
US
FD14EL03
23'-7 1/2" REF
FD14SP02
EL. 258'-1 1/2" REF
16"X18" REDUCER
FD14RD01
18"-FDW-11
EL 258'-6"
FD14EL01
FD14VA01
FD14TE01
(SKETCH No.021)
18" DIA OUTLET
NOZZLE HEATER E1-1A
60 DEG V
V63-7A
FD14SP01
FD14EL02
TURBINE BUILDING-HEATER BAY
REFERENCES: GIg 1157/J191182,G191163,5928-FS-125
REVISION 1: 11/24/91
VERMONT YANKEE PIPING EROSION-CORROSION INSPECTION PROGRAM
FEEDWATER LINE 16"-FDW-14
COMPONENT LOCATION SKETCH No.008

5.08

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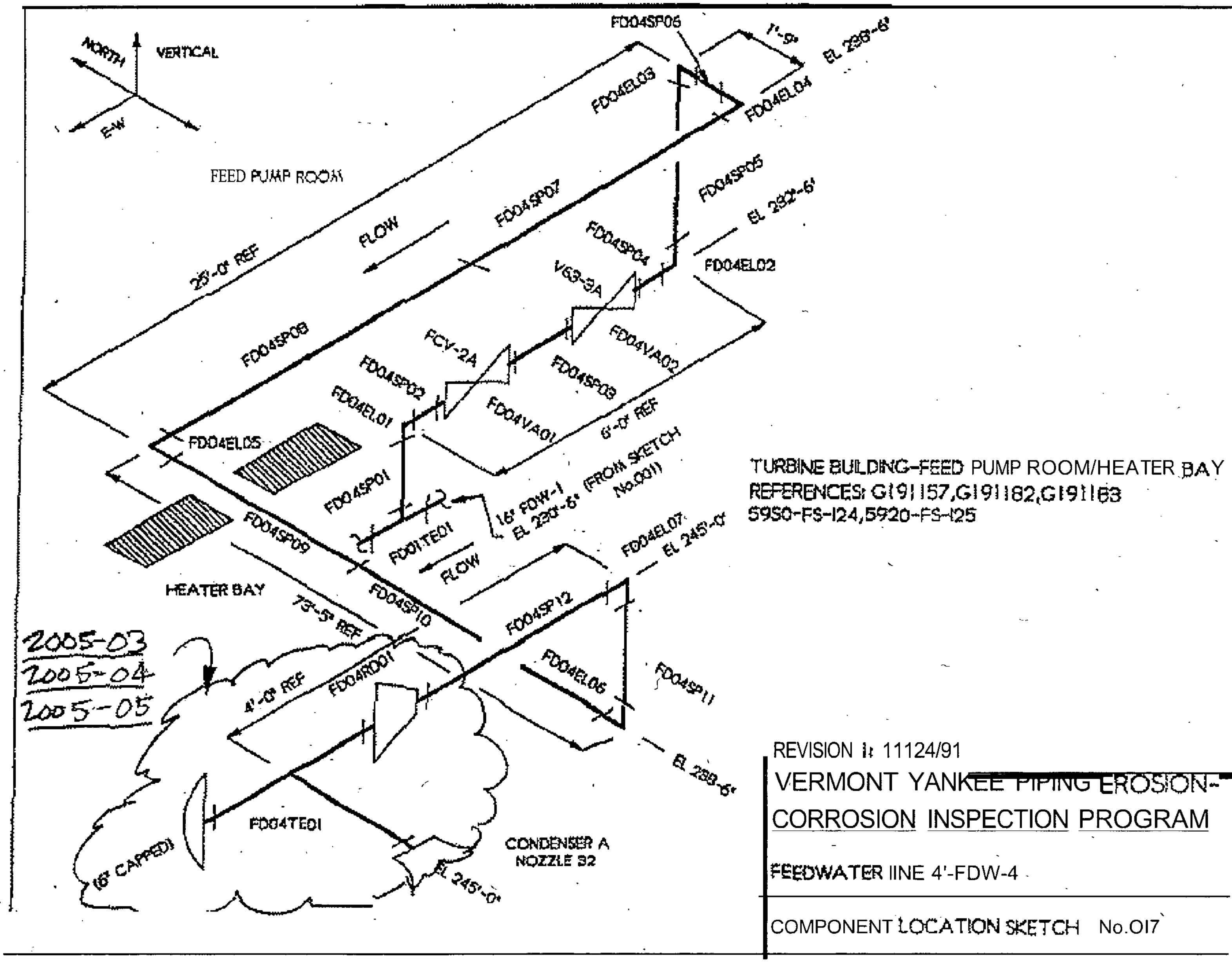
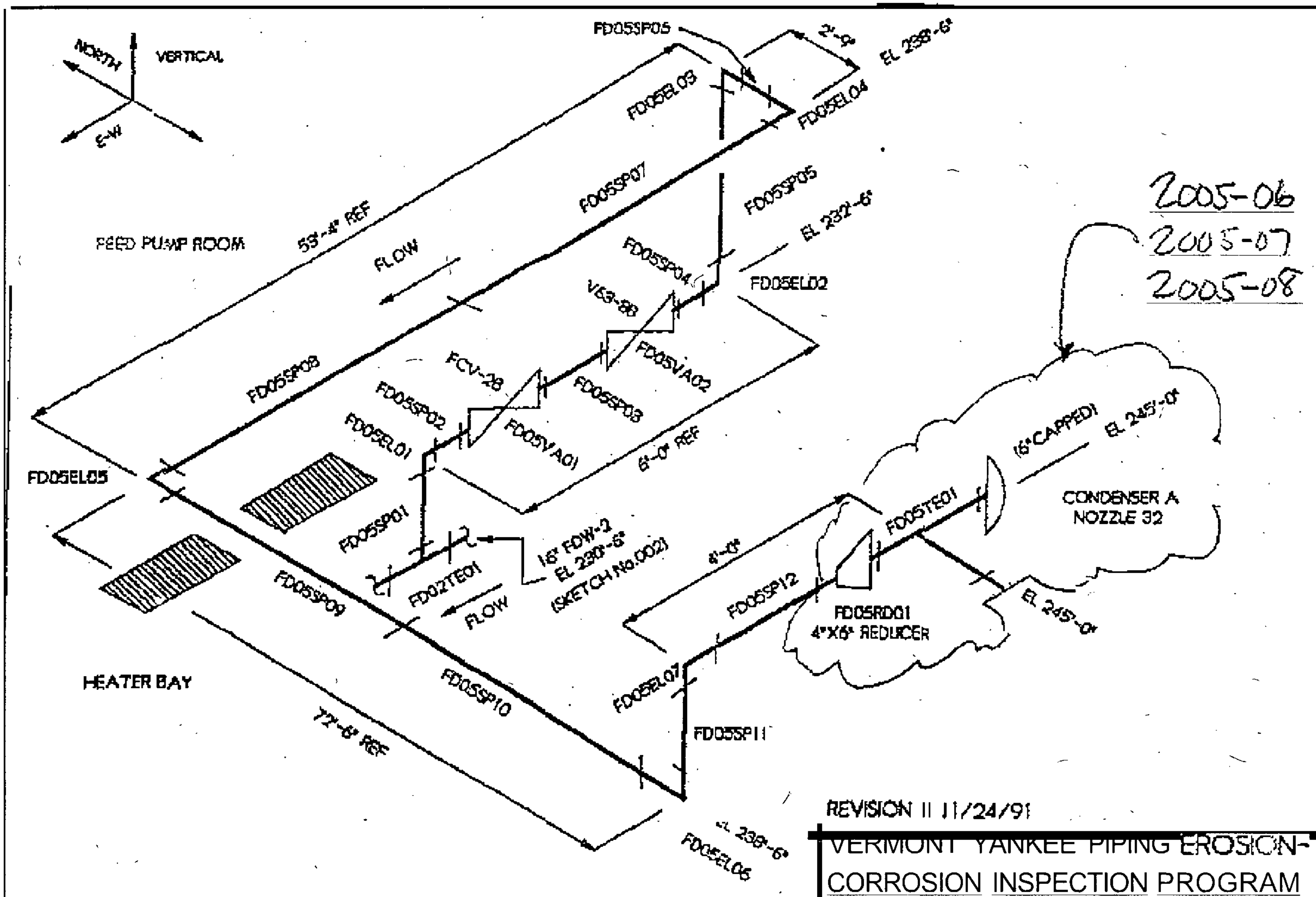


NEC037123



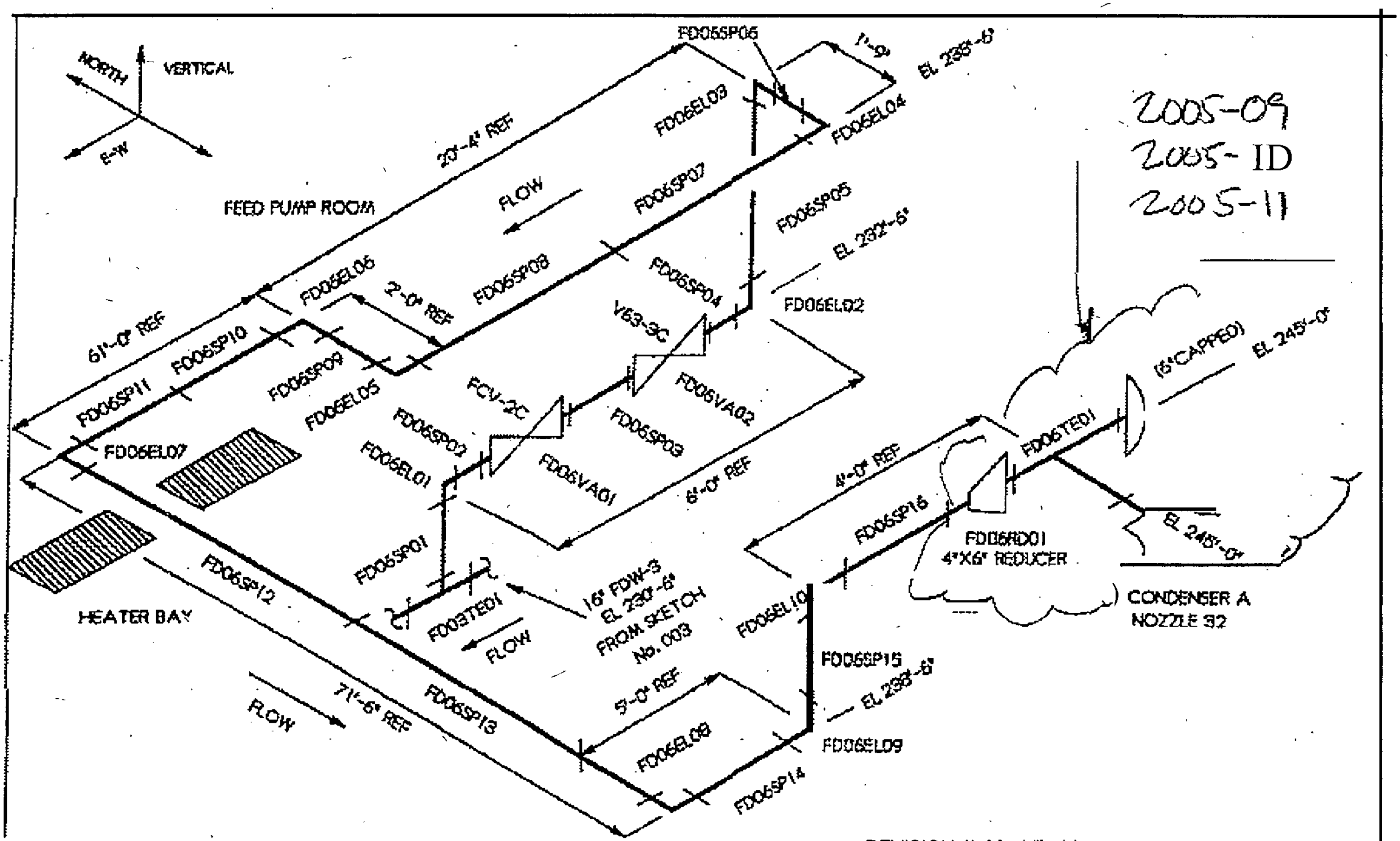
TURBINE BUILDING-FEED PUMP ROOM/HEATER BAY
REFERENCES: G191157,G191182,G191183
5950-FS-124,5920-FS-125

REVISION II 11/24/91

VERMONT YANKEE PIPING EROSION-CORROSION INSPECTION PROGRAM

FEEDWATER LINE 4"-FDW-S

COMPONENT LOCATION SKETCH "40.018



REVISION II 11/25/91

VERMONT YANKEE PIPING EROS10N-CORROSION INSPECTION PROGRAM

FEEDWATER LINE 4"-FDW-6

COMPONENT LOCATION SKETCH No.019

TURBINE BUILDING-FEED PUMP ROOM/HEATER BAY
REFERENCES: G19J157,G191182,G191183
5950-FS-124,5920-FS-125

NEC0?7125

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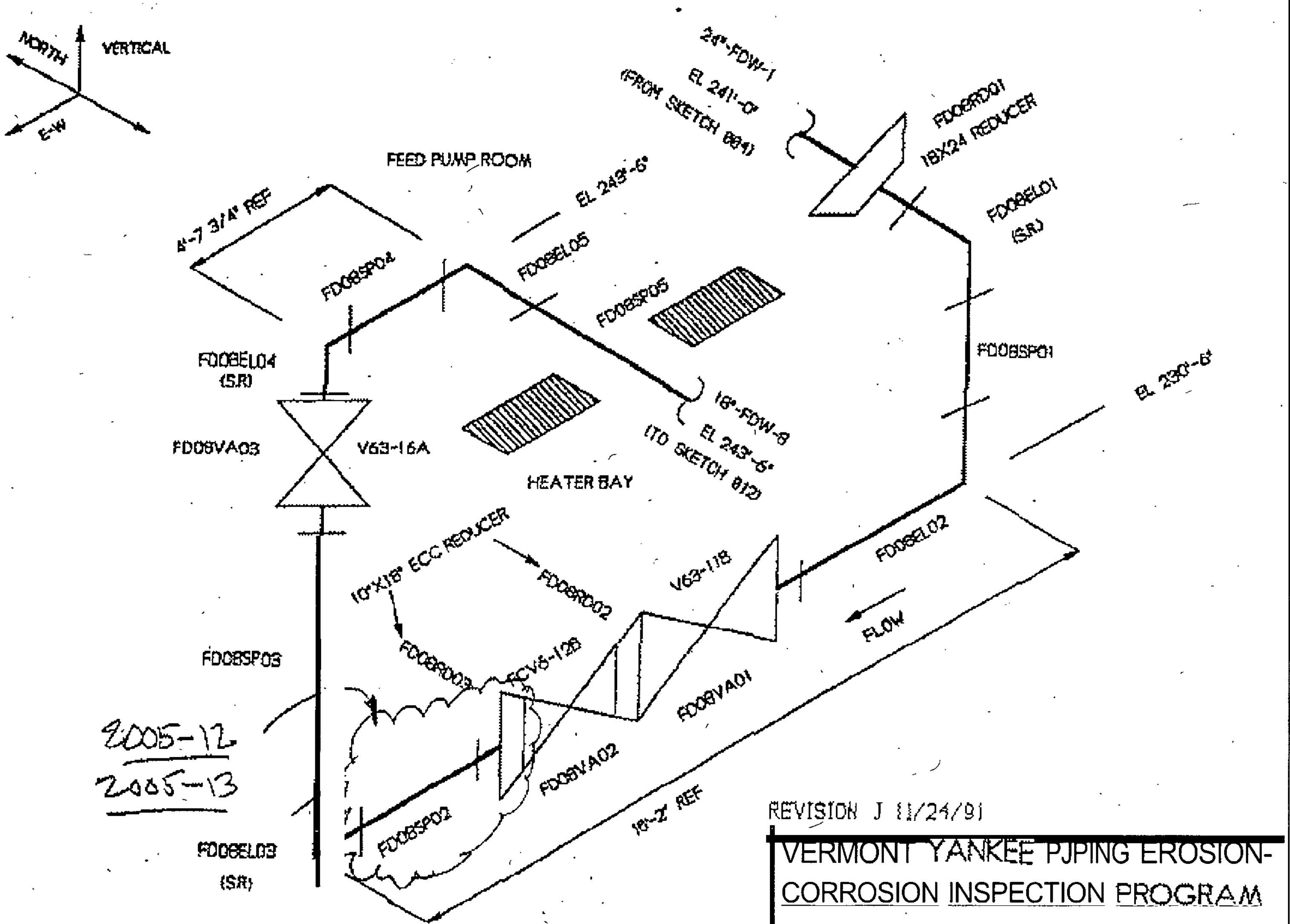


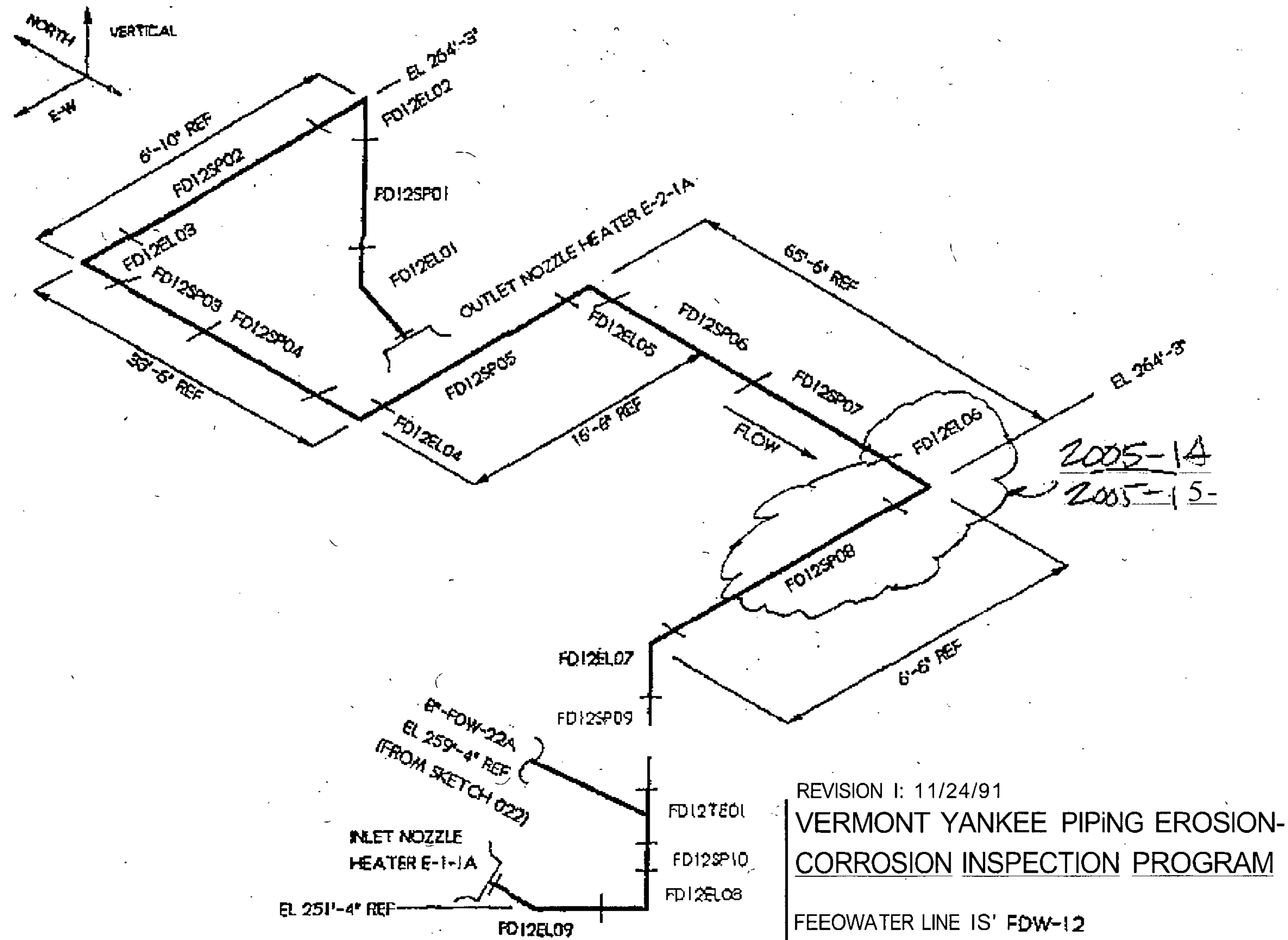
TURBINE BUILDING-FEED PUMP ROOM
REFERENCES: G191157,G191182,G191183,5920-FS-124

REVISION J 11/24/91

VERMONT YANKEE PIPING EROSION-CORROSION INSPECTION PROGRAM

FEEDWATER LINE 18"-FDW-B

COMPONENT LOCATION SKETCH No.011



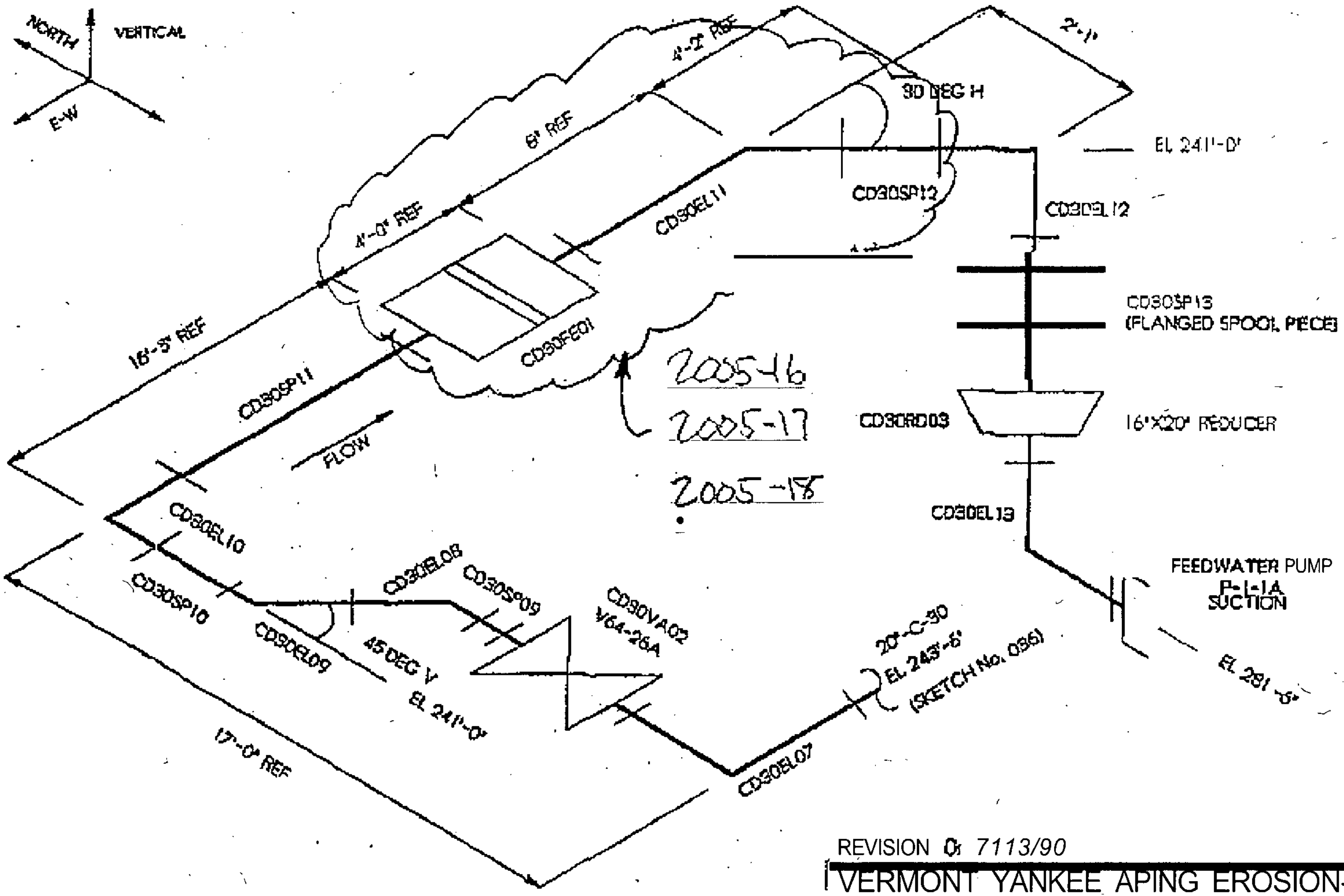
TURBINE BUILDING-HEATER BAY
REFERENCES: G191157,G191182,G191183,5920-FS-125

REVISION I: 11/24/91

VERMONT YANKEE PIPING EROSION-CORROSION INSPECTION PROGRAM

FEEDWATER LINE IS' FDW-12

COMPONENT LOCATION SKETCH No.007



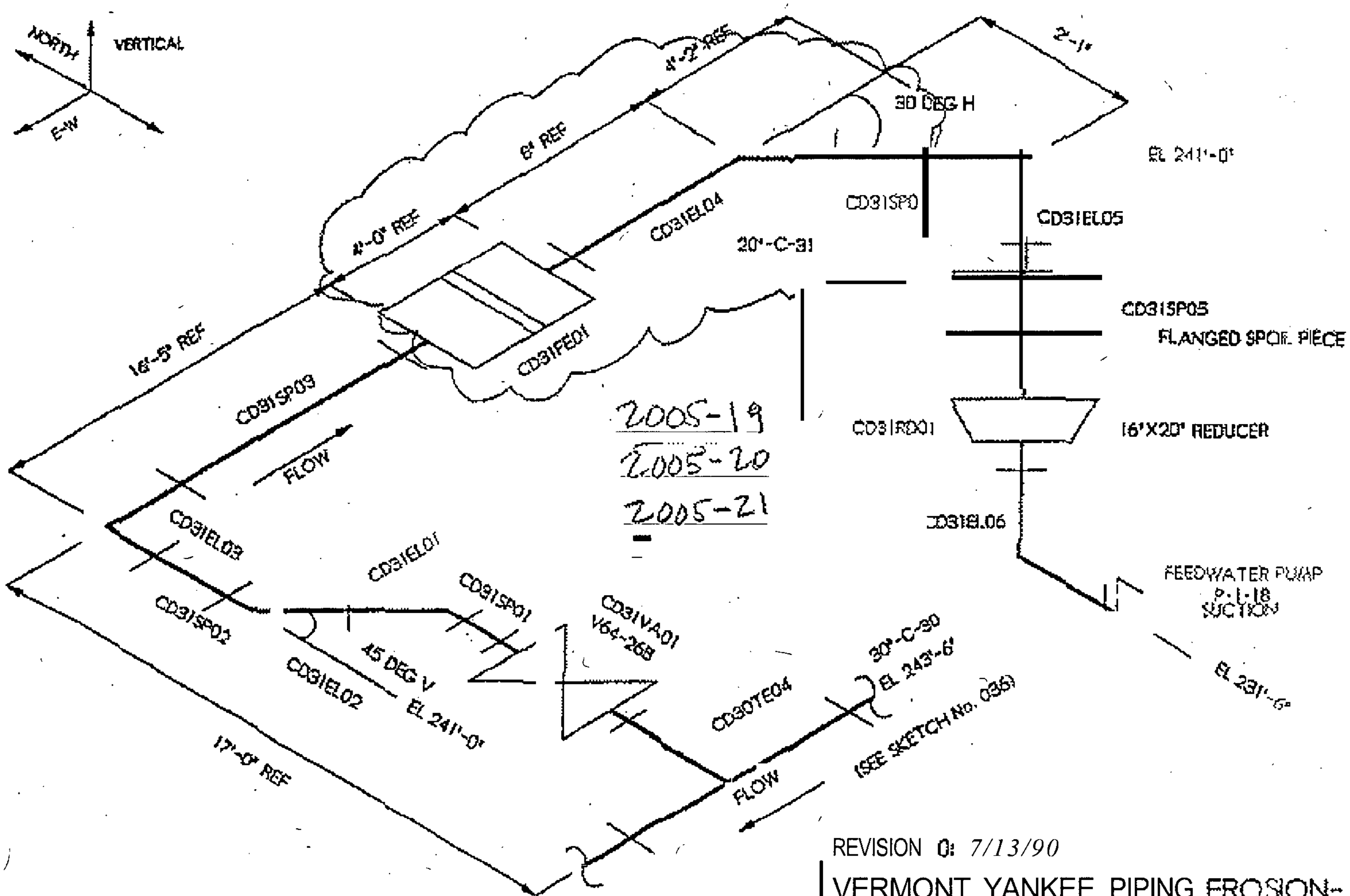
REVISION 0, 7/13/90

VERMONT YANKEE PIPING EROSION-CORROSION INSPECTION PROGRAM

CONDENSATE LINE 20"-C-30 (CONTINUED)

COMPONENT LOCATION SKETCH No. 037

TURBINE BUILDING-FEEDWATER PUMP ROOM
REFERENCES: G191157,G191186,G191187,5920-FS-116



REVISION 0: *7/13/90*

VERMONT YANKEE PIPING EROSION-CORROSION INSPECTION PROGRAM

CONDENSATE LINE 20"-C-31

COMPONENT LOCATION SKETCH No. 038

· TURBINE BUILDING-FEEDWATER PUMP ROOM
REFERENCES: G191157,G191180,G191187,5920-FS-1.16

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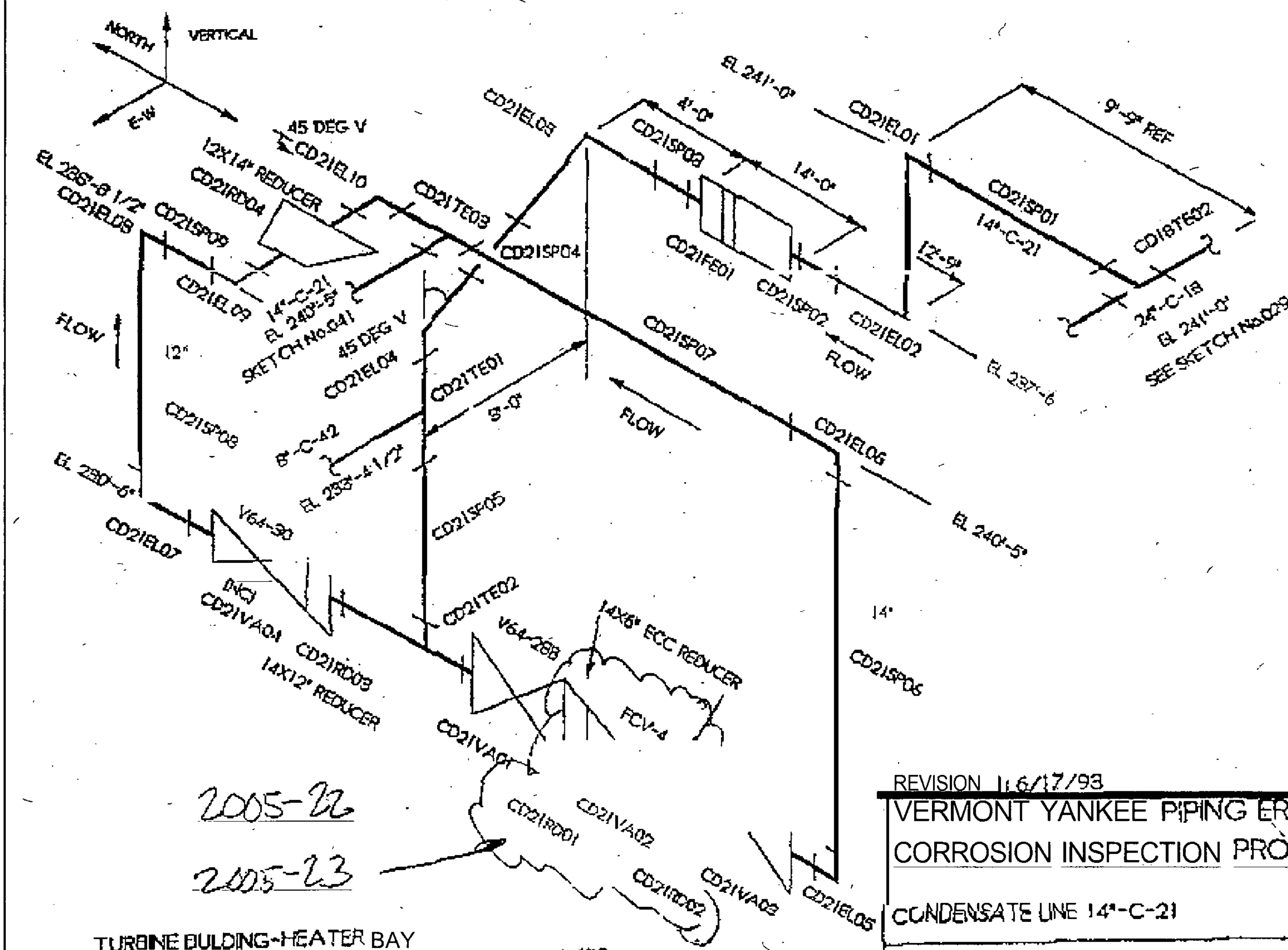

2005-22

2005-23

TURBINE BULDING-HEATER BAY
REFERENCES: C191158,C191188,C191189,5920-FS-135

REVISION 1 6/17/93

VERMONT YANKEE PIPING EROSION-CORROSION INSPECTION PROGRAM

CONDENSATE LINE 14"-C-21

COMPONENT LOCATION SKETCH No.040

NEC0371 30

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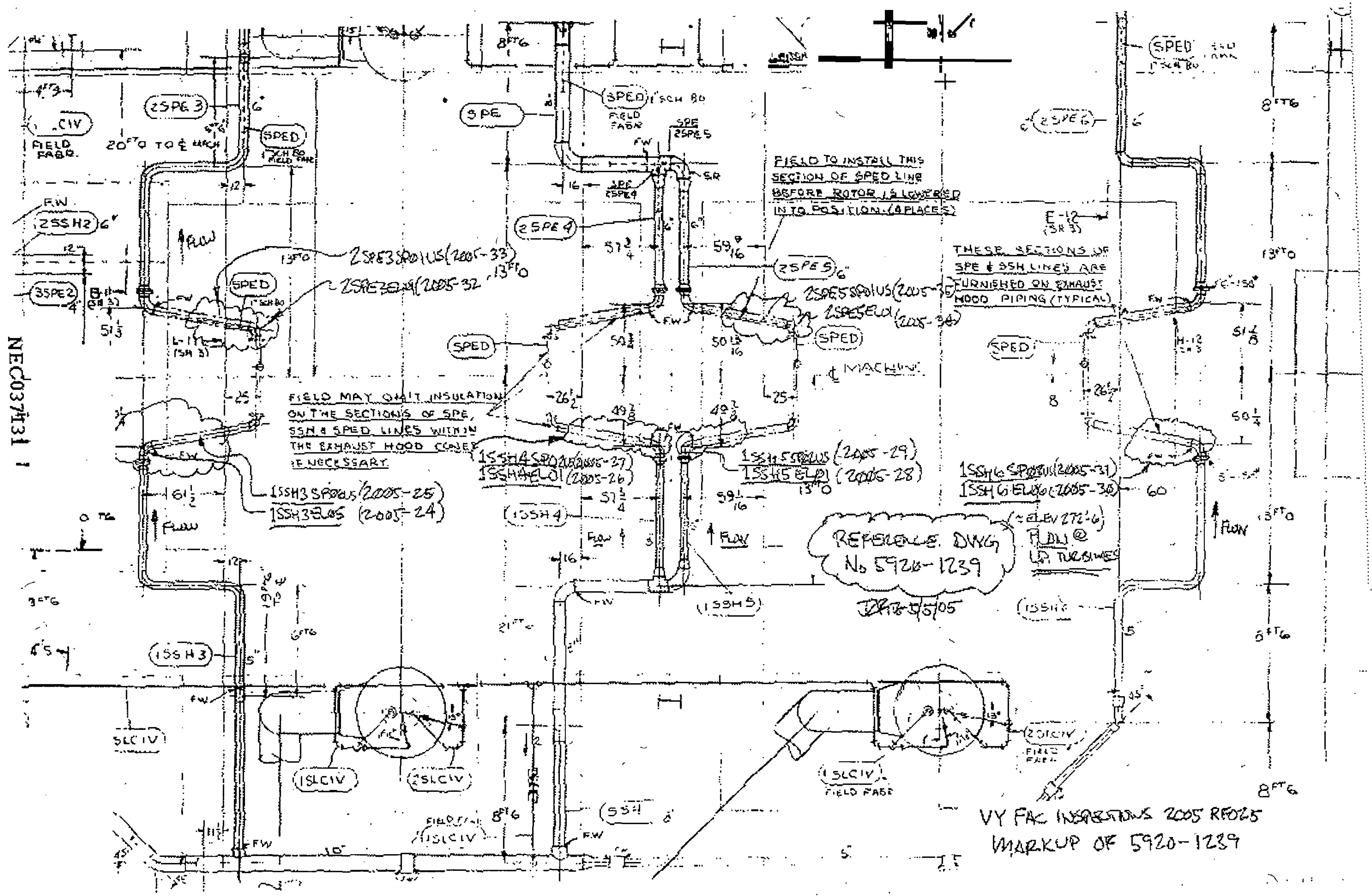
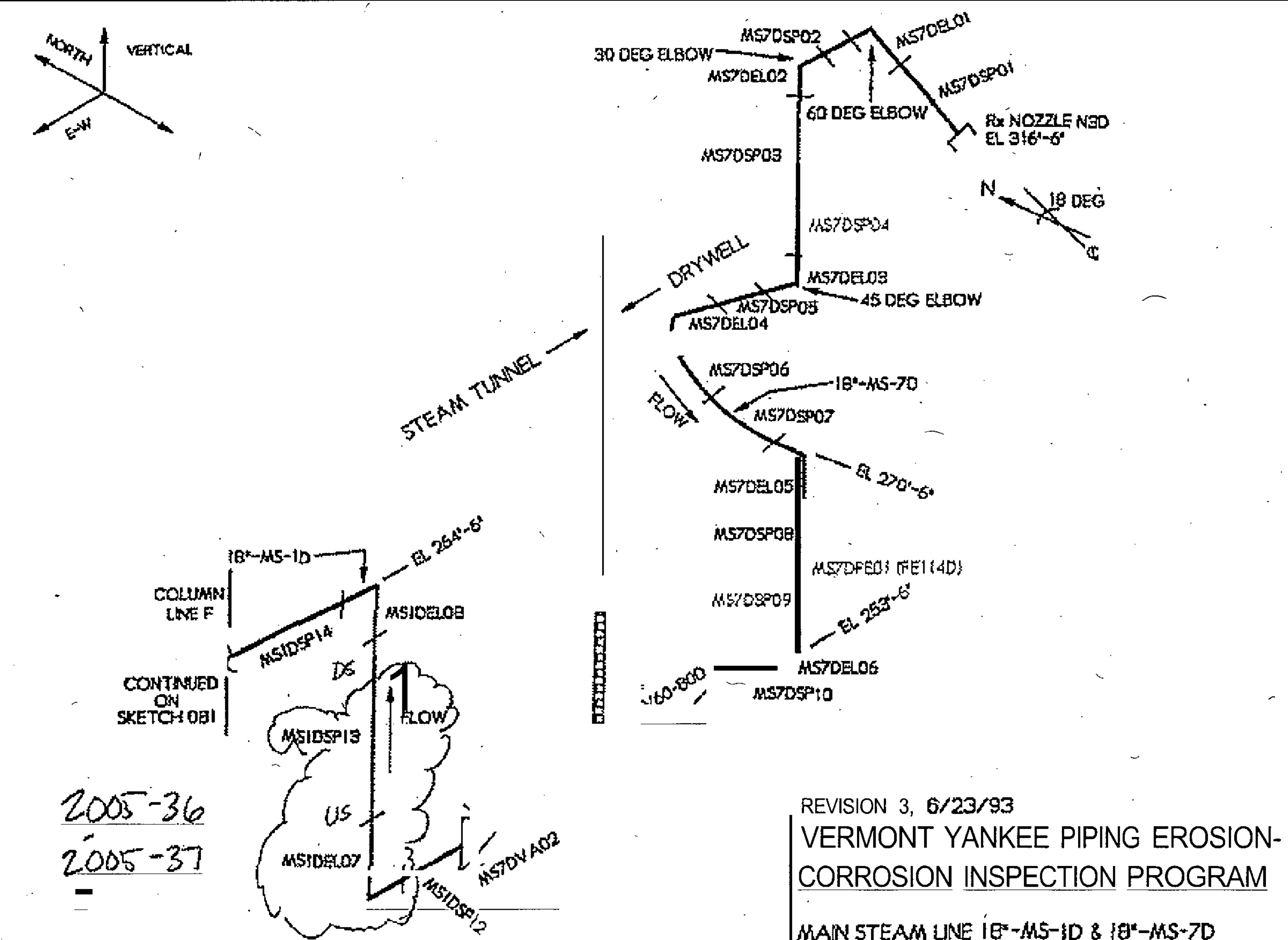


2SPE3
SPED
SPE
SPED 1" SCH 80
FIELD FABR
2SPE5
2SSH2 6"
3SPE2
2SPE4
2SPE5 6"
2SPE3SP01US (2005-33)
2SPE3EL01 (2005-32)
2SPE5SP01US (2005-35)
2SPE5EL01 (2005-34)
FIELD TO INSTALL THIS SECTION OF SPED LINE BEFORE ROTOR IS LOWERED INTO POSITION. (4 PLACES)
THESE SECTIONS OF SPE & SSH LINES ARE FURNISHED ON EXHAUST HOOD PIPING (TYPICAL)
2SPE6
FIELD MAY OMIT INSULATION ON THE SECTIONS OF SPE, SSH & SPED LINES WITHIN THE EXHAUST HOOD COVER IF NECESSARY.
1SSH3SP01US (2005-25)
1SSH3EL05 (2005-24)
1SSH4SP01US (2005-27)
1SSH4EL01 (2005-26)
1SSH5SP01US (2005-29)
1SSH5EL01 (2005-28)
1SSH6SP01US (2005-31)
1SSH6EL06 (2005-30)
1SSH4
1SSH5
1SSH3
REFERENCE DWG No 5920-1239
FLOW @ LP TURBINES
FLOW
℄ MACHINE
1SLCIV
2SLCIV
SLCIV
SSH
FW
VY FAC INSPECTIONS 2005 RFO25
MARKUP OF 5920-1239

NEC037431



REVISION 3, 6/23/93

VERMONT YANKEE PIPING EROSION-CORROSION INSPECTION PROGRAM

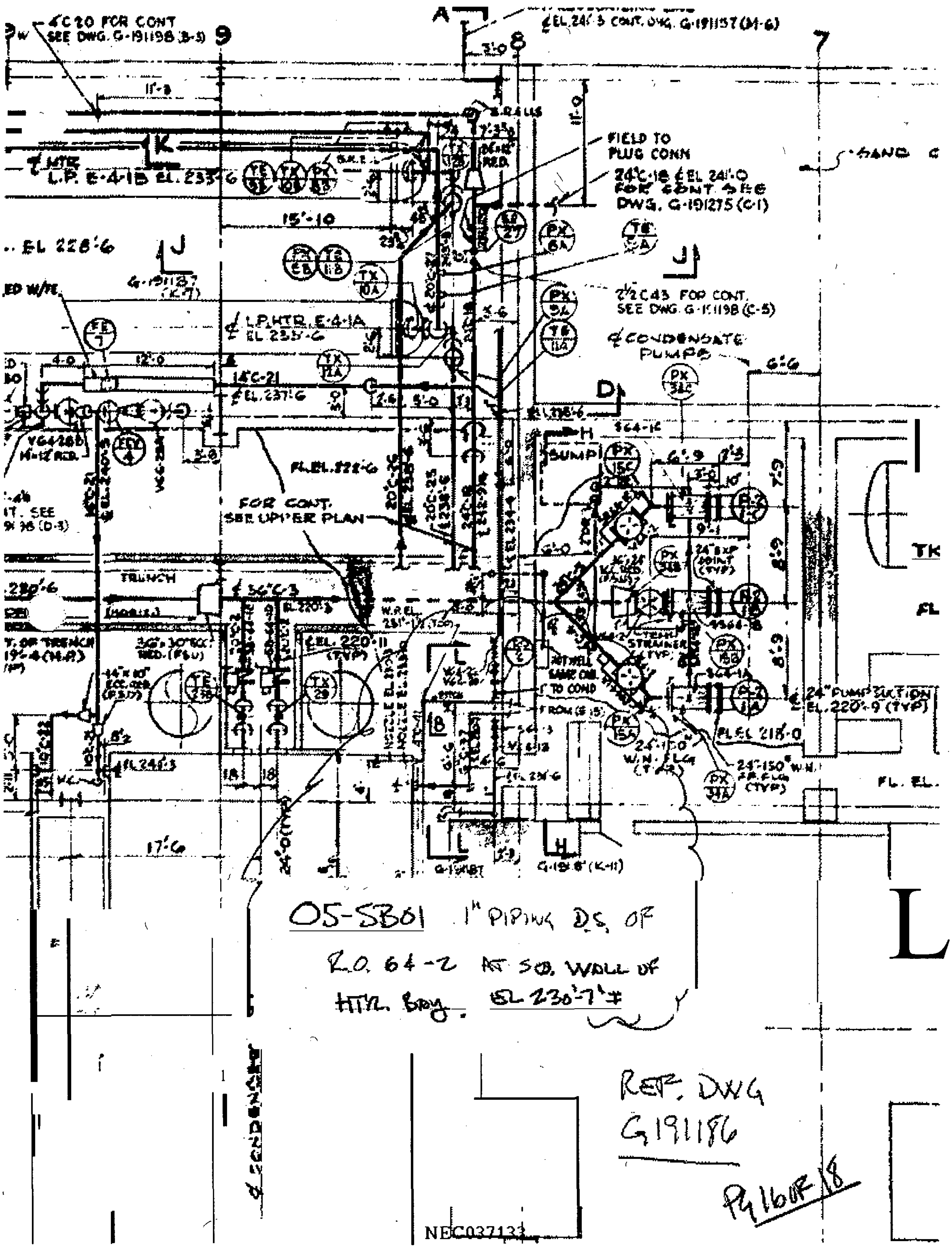
MAIN STEAM LINE 18"-MS-1D & 18"-MS-7D

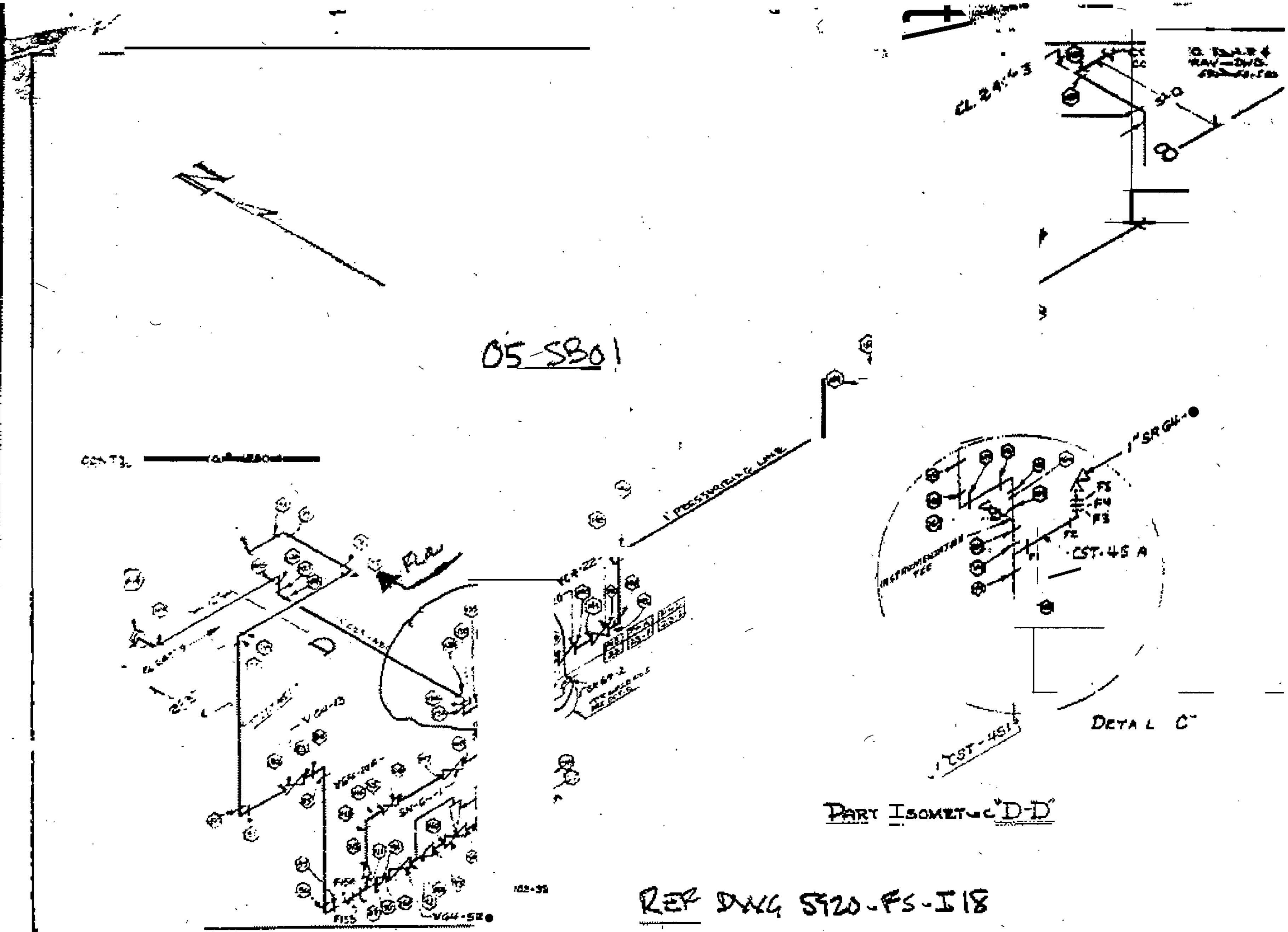
COMPONENT LOCATION SKETCH No.080

QRYWELL & STEAM TUNNEL
REFERENCES: G191167,G191182,5920-FS-13

Original Page 85 of 102

Pg 15 of 18


05-SB01 1" PIPING D.S. OF
R.O. 64-2 AT SO. WALL OF
HTR. Bay. EL 230'-7" ±
REF. DWG
G191186
Pg 16 of 18
FIELD TO
PLUG CONN
24"C-18 ℄ EL 241'-0
FOR CONT. SEE
DWG. G-191275 (C-1)
2½"C43 FOR CONT.
SEE DWG. G-191198 (C-5)
℄ CONDENSATE
PUMPS
℄ L.P. HTR. E-4-1A
EL 233'-6
FOR CONT.
SEE UPPER PLAN
TRENCH
SUMP
℄ 24" PUMP SUCTION
EL 220'-9 (TYP)
FL. EL. 218'-0
TK
L

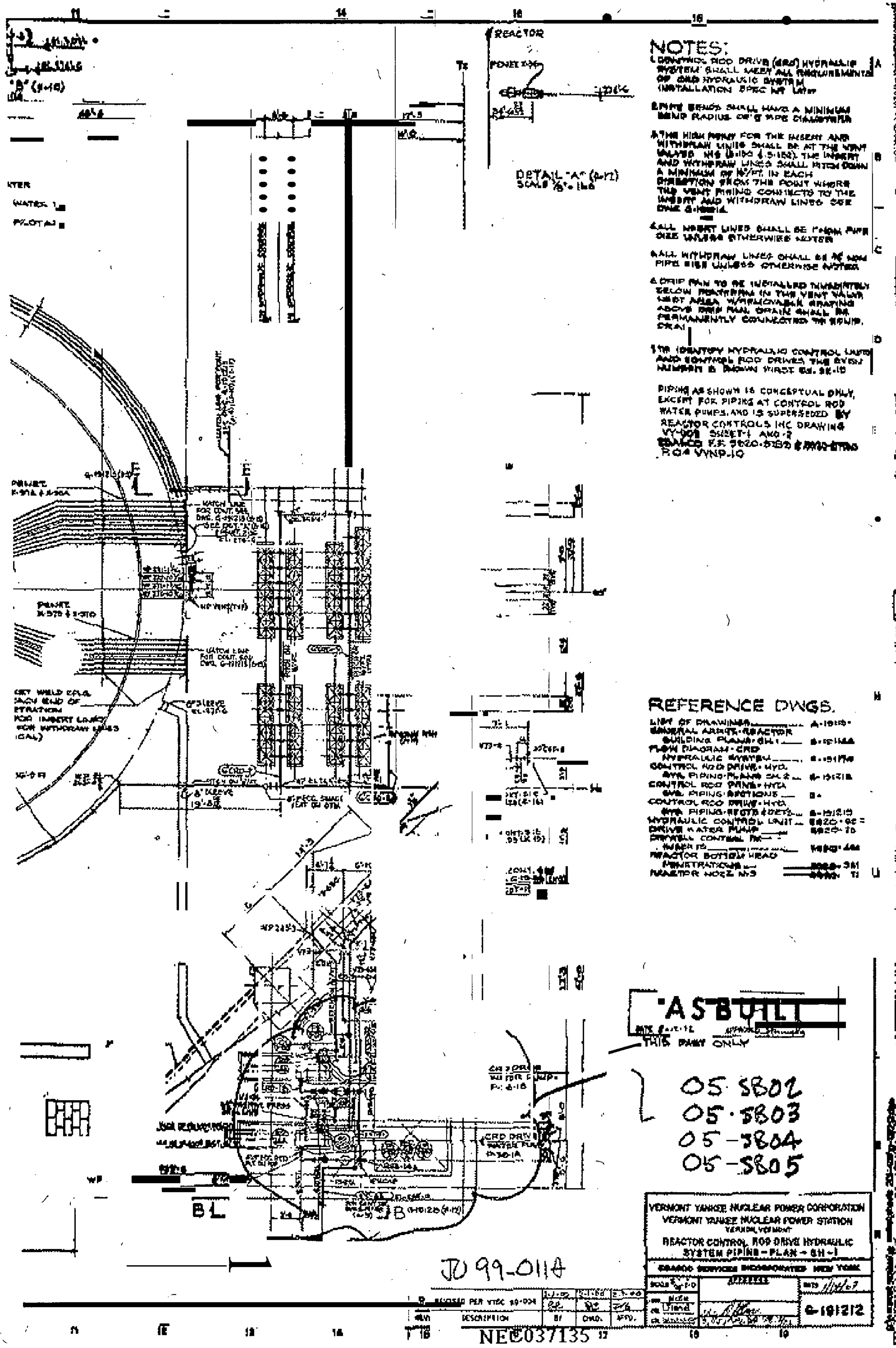


REF DWG 5920-FS-I18

PG 17 OF 18

WELL NO.

FE	CST-451-F16	121	CST-452-F11	154	CST-450-F33
69	F17	122	CST-452 F1	155	F34
80	F18	123	F2	156	F35
[illegible]	F19	12A	F3	157	F36
92	F20	125	F4	15A	F37
[illegible]	F21	12[illegible]	F5	153	126


NOTES:
PIPING AS SHOWN IS CONCEPTUAL ONLY, EXCEPT FOR PIPING AT CONTROL ROD WATER PUMPS, AND IS SUPERSEDED BY REACTOR CONTROLS INC DRAWING
DETAIL "A"
REFERENCE DWGS.
AS BUILT
THIS PART ONLY
05-5802
05-5803
05-5804
05-5805
CRD DRIVE WATER PUMP
VERMONT YANKEE NUCLEAR POWER CORPORATION
VERMONT YANKEE NUCLEAR POWER STATION
REACTOR CONTROL ROD DRIVE HYDRAULIC
SYSTEM PIPING - PLAN - SH-1
G-191212
DESCRIPTION
JU 99-0118
Pg 18 of 18

NEC037135

TAB 4

Pg 1 of 6

VERMONT YANKEE
SCOPE MANAGEMENT REVIEW FORM

Date: 11/1/05

Tracking Number: ______
(Assigned by Work Scope Control Coordinator)

Work Order Number: 04-004983-000

Reference Document: CR-VTY-04-2925 CA3 (CR, TA, DC, LO, etc.)

Initiator: JAMES FITZPATRICK

Approved By: ______ Dept. Mgr.

Location of Work to be Performed: TURBINE

ADDITION ☐ DELETION ☒ CHANGE ☐

Description

PERFORM UT INSPECTIONS OF STEAM SEAL HEADER PIPING UNDER FAC PROGRAM. INSPECTIONS ~~2005-24 THROUGH 2005-35~~

Justification for Request

INTERFERES WITH CRITICAL PATH WORK PLANNED ON L.P. TURBINES SEE ATTACHED MEMOS FOR FAC PROGRAM AND DEFERRAL OF RESTORATION OF TM 2004-031.

Review Process

Additional Cost:
Duration and Scheduling Impact:
Assigned Dept./Man-Hours to Complete:
Source of Manpower/Other Scope Impacted:
Dose, Chemistry, Safety Implication:
Engineering Impact: Man-Hours/Engineering Dept.
Optional Ways to Address:

Approval Process

Please provide a brief justification

Scope Review Committee Recommendation/Planning Priority: Approve Delete

Priority "C" WO Responsible Dept Approval ______

General Manager, Plant Operations: ______ Approve/Disapprove Date: 11-1-05

EMPAC Change Made for Event Code & Priority ______
sec Date

Log Updated:
~~Copied to Work Control, Outage Scheduling~~

VYPPF 7102.01
PP 7102 Rev. 2
Page 1 of 1

NEC037136

Pg 2 of 6

Prepared By: James Fitzpatrick
Date: 11/1/05

RFO 25 FAG Program inspections location nos. 2005-25 through 2005-35

References:

Work Order 04-004983-000, FAC Inspections
Work Order 04-004983-010, Surface Preparation on SSH piping
TM 04-031
Work Order 04-004884-006
ER-05-0190
CR-VTY-04-2985 CA3

Background:

CR-VTY-2004-02925 doouments a steam/water leak on the turbine steam seal piping, line 1SSH4 to the No.4 packing. TM 2004-031 installed a temporary leak enclosure on this line. Inspections on Turbine Steam Seal Piping were included in the scope of the FAG program for RFO 25 per CA3 of CA-vrY-2004-02925. The purpose of these inspections is to determine the extent of condition on the remaining steam seal piping.

Work Scope

These inspections require access to the SSH & SPE piping on elevation 272 of the Turbine Building. The piping is located under the IP turbine appearance lagging deck plates and requires removal of section of the plates to access the piping for surface preparation and inspection. It was intended that these inspections be performed along with restoration of Temp Mod 2004-031 (W.O. 2004-4884-006).

Discussion

Restoration of TM 2004-031 was removed from the outage soope on 10/24/05 due 10 interference with critical path work planned on the LP lurbines. A detailed ralionale for delaying resloration of the TM from RF025 was deveioped by George Benedict on 9/98105 and is attaohed here. The same reasoning and technioal basis applies to these Inspections.

In addition these inspeotions are not programmatically required under PP 7028 (Piping FAG Inspection Program). The inspeotions were added to the RFO 25 scope to determine the condition of the piping at parallel and similar locations on the Steam Seal piping as the 2004 through wall leak.

The system is a low pressure system with piping looated in the heater bay or under the turbine deck plating. Deferral ot these inspections does not pose a significant personal safety hazard as exposure to these lines during operation is minimal. The possibility of a leak at another location on the Steam Seai piping still exists_ However, the low operating pressures and the results of UT measuremenls made on lhe 1SSH41ine at the location of the existing ieak indicate that any failure would be a pinhole type leak vs, a catastrophic failure of the pipe.

Entergy

Prepared By: G.13enedict
Date: 9/28105

Pk 3 of 6

Replacement ofN4 Steam Supply Piping

References:

Work Order 04-4884-06
TM 2004-031
ER 05-0190

History:

The steam seal supply line to TB-1-1A, N4 packing developed a leak from what appears to be the result ofpipe erosion on one ofthe pipe radiuses. Team Inc. was contacted 10 develop on-line repair options and determined that the most appropriate long tenn repair would be to instill! a pre-fabricated clamping device. The clamp was fabricated as recommended and successfully installed per the above referenced Temporary Modification (TM 2004-03!).

Work Scope:

The permanent repair for the N4 steam seal supply line is currently scheduled to be implemented during RFO 25. The pipe clamp and the degraded section ofpipe will be removed and new piping will be field fit and installed. To facilitate this work, it will be necessary to remove sections ofthe LP turbine appearance lagging deck plates to gain access to the piping. Use ofthe overhead crane will also be required to remOVe/install piping and dcck plates.

LP Turbine and Steam Seal Pipe Repair Interaction:

During RFO 25 a significant amount ofwork will be pcrfonned on thc LP turbines which are located in the immediate area ofthe degraded N4 steam seal supply line. The LP turbines will be completely dismantled to facilitate the installation ofthe new 8th stage diaphragms and to perform the required tcn year inspection. The location ofthe degraded steam seal line is directly between both LP turbines and implementing the LP inspection in conjunction with the steam scal line repair will create personnel safety hazards, potential equipment damage, and logistical complications.

Entergy

Prepared By; G. Benedict
Date: 9128105

P4 4of6

The following represents the specific issues that will be present during the implementation of the N4 steam seal line replacement and the LP turbine inspection:

Personnel Safety:

- Fall and drop hazards will be created by both work crews in proximity to both work areas. Open holes will exist on the turbine deck appearance lagging deck plates and in the area between the LP inner casings and exhaust hoods. Although, personnel protection barriers and equipment will be utilized to mitigate fall and drop hazards, personnel awareness, focus, and goal will be on each individuals own task. The drop and fall hazards will be continually changing as each work activity progresses and although personnel are required to communicate changes to safety hazards these types of changes will be extremely difficult to manage due to the pace of the LP turbine inspection activity,

- The crew working on the steam seal piping will continually be interrupted due to overhead hazards from materials being removed and returned to the LP turbine centerline. Once again dne to the pace of the LP turbine inspection and the fact that the steam seal piping replacement crew will be in and out of the work area which is not visible from the turbine floor only increases the potential to inadvertently transfer a load over the piping replacement crew.

Equipment Safety and Quality:

- The removal and installation of the steam seal piping will involve welding and grinding activities. Shielding can and must be installed to prevent inadvertent weld flash, slag, and grinding dust, however, performing these types of activities in the vicinity of open bearing oil sumps, exposed shaft journals, and bearing babbitt surfaces increases the risk for accidental damage.

Schedule and Logistics

- The LP turbine work is the primary critical path activity for the Outage and any delays encountered by the implementation of the N4 steam seal supply line repair will most likely result in an increase in duration. The repair of the steam seal line will require a moderate use of the turbine building crane to remove/install deck plates, piping, and appearance lagging. In addition, crane support will be required to remove damaged pipe...install and fit-up new pipe sections.. ,remove new section to perform non-field welds...and permanent installation. TIere is zero turbine building crane availability during RFO 25,

- The open hole caused by the removal of deck plating will cause the "A" LP to be logistically separated from the "B" LP on the right side of the centerline which

,will create a delay in the transfer oftooling and materials between LP "A" and "B".

- Asbestos coneem: There is a potential that the steam seal line being repaired contains asbestos insulation. Any asbestos insulation issues could shutdown work on the turbine deck.

- Maintenance resources: Mamtellallce crews assigned to the steam seal line repair have 7 shifts available to perform this repair. Ifthere are any delays in performing the repair (e.g. coordination issues or emergent issues during the work), the maintenance crew would be required to leave the steam seal pipe repair and return to the refuel floor.

Technical Basis for Deferral:

Team Inc. was contacted (o determine the feasibility ofoperating the unit fol' an additional cycle with the Team clamp in place. The response from Team IllC. was very favorable with regard to operating an additional cycle with the clamp in place. According to Jim Savoy (Team Inc. District Manager) many commercial industrial facilities that have utilized clamps similar to the one installed on the N4 steam seal supply line have operated for extended periods much greater than the requested 18 months.

The steam seal supply IS approximately 2 - 5 lbs. ofpressure with a maximum temperature of 255 degrees F. This is considered very low in comparison to many ofthe applications that Team Inc. has installed similar long term clamps on. Ifthe clamp is left installed for an additional operating cycle there is a risk that the clamp will leak once the plant is placed back on-line. Although considered a low probability, the risk is due to the thermal cycling ofdissimilar materials that are utilized in the clamping and sealing process. Ifa leak were to occur Team Inc. would re-inject the clamp with sealant which has been successfully perfOlmed at other locations.

Pg 6 of 6

VERMONT YANKEE
SCOPE MANAGEMENT REVIEW FORM

Date: 10/23/05

Tracking Number: ____________
(Assigned by Work Scope Control Coordinator)

\Work Order Number: 04-4884-06

Reference Document TM 2004-031
(ER, MM, TM, 0028, etc,)

Initiator: Lee Kitchen

Approved By: ____________
Dept_ Mgr.

Location of Work to be Performed: TURB DECK

ADDITION 0 DELETION ☑ CBANGE ☐

Description

Replacement of steam seal supply piping. There is a temp leak repair in place.

Justification fo, Request

Interferes with critical path work planned on the LP turbines. See attached memo that documents the problem, that would delay the critical path on the turbine deck.

Review Process

Additional Co,t:
Duration and Scheduling Impact:
Assigned Dept./Man-Hours to Complete:
Source of Manpower/Other Scope Impacted:
Dose, Chemistry, Safely Implication:
Engineering Impact - Man-Hours/Engineering Dept.
Optional Ways to Address:

Approval Process

Please provide a **brief justification**

Scope Review Committee Recommendation/Planning Priority:

Priority "C" ... nsible Dept Approval

Pl.nt Manager: [signature] Approve Disapprove Date: 10-24-05

EMPAC Cha ... or Event Code & Pri rity

SCC Date

Log Updated:

Copies to Work Control, Outage Scheduling.

VYPPF 7102.01
pp 7102 Rev. 1
Pageloft
LPC #15

JCH

TAB 5

RFO-25 Piping FAC Inspections
Outage Scope Challenge Meeting 5/4/05

Short or Cryptic summary of what the project involves and why we need to complete the project in RFO 25 (e.g. regulatory requirement, risk to generation, program requirement, appropriate management of the asset)

In response to USNRC Generic letter 89-08, inspections of piping components susceptible to damage from Flow Accelerated Corrosion (FAC) are performed each refueling outage. The planning, inspection, and evaluation activities are currently defined in program procedure PP 7028, "Piping Flow Accelerated Corrosion Inspection Program". Before the start of RF025, VY will transition to a new Entergy procedure "Flow Accelerated Corrosion Program", ENN-DC-315.

Description of the scope of the project, what it encompasses, options that have been considered {identify minimal required vs. discretionary could be deferred scope.) Other outage scope that interlaces with or can be included in this project: Impacts on others.

The scope of the inspections for each refueling outage is based on previous inspection results, predictive modeling, industry and plant operating experience, postulated power uprate effects, and engineering judgment. The scope for the Fall 2005 RFO is defined in Design Engineering-MIS Memo VYM *2004/007,* Revision 1. The 2005 RFO Scope includes:

External Ultrasonic Thickness (UT) Inspection of 37 large bore components at 16 locations. Includes:

- 5 components recommended for repeat inspections based on prior UT data
- 2 components for CHECWORKS model calibration
- 6 components based on Operating Experience (Mihama Event)
- 6 components downstream of leaking N.C. valves (identified from TPM)
- 4 components based on increased EPU flows
- 2 components D.S of FCV -104-4 (suspected cavitation)
- 12 components based on current through wall leak in SSH at LP turbines

External Ultrasonic Thickness (UT) Inspection of 5 sections of small bore piping based on industry experience. Includes 4 sections of piping downstream of restriction orifices at the CRD pumps.

Internal Visual Inspection of two 36 inch CAR lines to assess changes in flows from HP turbine modifications installed in RFO 24. Internal Visual inspection of the only remaining carbon steel 30 inch diameter line 30"-8.

Pre-outage scope and long lead time parts/contracts that have been identified.

None

RFO-25 Piping **FAC** Inspections
Outage Scope Challenge Meeting *5/4/05*

Initiatives, creative opportunities, unique problems associated with the project.

None

The inspecUon process used is the industry standard. Removal of insulation and surface preparation are required for the UT equipment. Remote methods which do not require insulation removal are still in the development stage, and do not currently have the accuracy required to trend low wear rates (EPRI CHUG). Phosphor Plate Radiography which is currently being adopted to screen small bore components without insulation removal is primarily applicable to PWR plants. limited use on BWRs,

Design Engineering – MIS has minimized the number of Inspections performed each RFO. VY has traditionally trended well below industry average number of components inspected each RFO. This is primarily due the original design of the plant and replacements with Chrome-Moly piping_ Recent trends in numbers of components inspected at other plants show reduced numbers of inspections based on piping replacements.

Identify additional organizational support required, and specifically, management support ɔcessary.

Inspections will be performed by the ISI personnel. Scheduling and staffing will be coordinated with other ISI activities. Inspections are performed using approved NDE procedures. Training on inspection procedures is performed under the ISI program, Grid marking per new ENN Standard ENN-EP-S-005

Primary DE-MIS interface is the ISI level III and/or ISI Program Engineer for coordination in review and approval of inspection data. Interface with craft & other plant groups is normally through establlshed links in the ISI program. Unusual situations which require additional support will be raised to management level as required,

Two DE-MIS engineers (J.Fitzpatrick & T.O'Connor) currently trained in evaluation procedures and have prior VY FAC Program Experience. Other DE-M/S engineers with pipe stress experience can be trained on shari notice. The number of inspections Is slightly higher than the last two outages, Coverage will be provided 7 days a week (or as required) to evaluate UT data.

The FAC Program Coordinator (J,Fitzpatrick) is responsible to insure that inspections are performed and the data is evaluated in accordance with the program requirements. Activities will be coordinated with the 151 coordinator (Dave King), Any problems that arise that can not be handled at the engineer level, will be elevated per outage management guidelines (30 minute rule, etc.),

RFO-25 Piping FAC Inspections
Outage Scope Challenge Meeting *5/4/05*

Identify any preparation issues necessary to meet upcoming outage milestones.

- Coordination with LP Turbine work for inspection of SSH components (physical space)
- Coordination with LIP Turbine/Condenser work for ventilation path (opening) for the 30" B Cross Around Line and for a window to perform inspections (noise issue).
- ER for Design Engineering - Fluid Systems to develop a (paper) Design Change to reduce the piping design pressure in the Feedwater Pump Bypass Lines at the condenser. Current design pressure for the piping attached directly to the condenser is 1900 PSI. Local sections of carbon stee! piping remain at the condenser. Leaking valves during past operation cycles may have resulted in increased wear in carbon steel section of line.

Identify if all necessary outage and pre-outage WO's for the projecUprogram scope are generated.

Work Orders to for support activities and inspections (04-4983-000 series) w/ Jim Griffin @ Program

Identify if any opportunities to perfonn any part of this scope could be completed pre-outage?

The only components which are not high temperature and are in an accessible location during plant operation are 4 sections of smali bore piping downstream of restriction orifices at the CRD pumps. These may be inspected during operation. However, this is a high noise area.

(UNINSULATED.)

TAB 6 Pg 1 of 2

Engineering Standard Review & Approval Form

Engineering Standard Change Classification

New	Revised	☐	Cancel	☐	Editorial	☐	Temporary (TCN)	☐

[redacted] Standard [redacted]	[redacted]	[redacted]	[redacted]
Flow Accelerated Corrosion Component Scanning and Griddina Standard	ENN-EP-S-005	0	N/A

Functional Disci [redacted]	En [redacted] Owner	[redacted] Pre [redacted]
Engineering Programs	Jeffery Goldstein	Ian Mew

Site Conductin Reviews

ANO	0	ECH	O	GGNS	O	WF3	O
IP	0	JAF	O	PNPS		WPO	

[redacted]

Review T	Yes	No	Reviewer Name/Signature	Date
Technical Review (See Not. below for Design Change Standards)	☒	0	James C. Fitzpatrick JCF	9/21/05
Independelll Design Verification (See Note below for Design Change Standards)	☐	☒		
10CFR50.59/Process Applicability Review (attach screening and evaluation documents) Sa. Note below for Desi n Chan e Standards)	☒	0	James C. Fitzpatrick JCF	9/21/05

Note: *Reviews for Design Change Standards are Documented within the applicable ER*
• An ER Number is re uired for Desi Chan e Standards, onl

ER Number

Cross Discipline Reviews (De rtment Name)	01	☒	Reviewer Name / Signature	Date
N/A				
Site En ineering Standard Champion			Scott D. Goodwin S D Goodwin	9-22-05

Editorial Change {TCN Approval

Name: [Signalure: Dale:

Comments Section

Comments Made [redacted] ☒ Comments Attached [redacted]
TCN Change Below ☐ [redacted] e Attached
TCN Effectiv

Comments/TCN Chalwe;

This standard replaces VY specific "Component Gridding Guidelines" previously contained in Appendix A of VY NDE procedure NE-8053. NE-8053 has been superseded by ENN-NDE-9.05

All VY comments were resolved during development of this standard.

Ph 2082

ENTERGY

ENN
ENGINEERING
STANDARD

ENN-Ep $-OO5 Rev. 0 Effective Dale: *JAFIWPO 9/1/04*
PII 61110$
IPEC 10J1104

Flow Accelerated Corrosion Component Scanning and Griddiog Standard

Applicable Site(s):
11'10 11'2 ☒ 11'3 ☒ JAF ☒ PNPS ☒ VYD

Safety Related: ___ Yes

_x_ No

Prepared by: Ian Mew ... 8/11/04
Print Name/Signature/Date

Approved by: Jeffrey Goldstein ... Dale: 8-11-04
Engineering Guide Owner

NEC037146

TAB 7
PAGE 1 OF 2

Engineering Standard Review & Approval Form

Engineering Standard Change Classification							
New	☒	Revised	0	Cancel	0	Editorial	0
Temporary (TCN)	0						

Engineering Standard Title	Doc. No.	Rev No.	TCN No.
Pipe Wall Thinning Structural Evaluation	ENN-CS-S-008	0	

Functional Discipline	Engineering Standard Owner	Engineering Standard Preparer
Civil/Structural	R. Penny	H. Y. Chang

Site Conducting Reviews

ANO	0	ECH		GGNS		RBS	D	WF3	
IP	☒	JAF	☒	PNPS	☒	VY	☒	WPO	☒

Review Type	Yes	No	Reviewer Name/Signature	Date
Technical Review (See Note below for Design Change Standards)	☒	0	James C. Fitzpatrick	9/21/05
Independent Design Verification (See Note below for Design Change Standards)	☒	0	James C. Fitzpatric	9/21/05
10CFR50.59/Process Applicability Review (attach screening and evaluation documents) (See Note below for Design Change Standards)	☒	0	James C. Fitzpatrick	9/21/05

Note: *Reviews for Design Change Standards are Documented within the applicable ER.*
• An ER Number is required for Design Change Standards only.

ER Number

Cross Discipline Reviews			Reviewer Name / Signature	Date
Department Name	☐	☒		
N/A				

Site Engineering Standard Champion	Scott D. Goodwin	9-22-05

Editorial Change / TCN Approval

Name:	Signature:	Date:

Comments Section			
Comments Made Below	☒	Comments Attached	
TCN Change Below	☐	TCN Change Attached	
TCN Effective/Expiration Date			

Comments/TCN Change:

All VY comments resolved during development of this standard.

NEC037147

Pg 2of2

Fitzpatrick, Jim

'rom: Fitzpatrick, Jim
ent: Tuesday, September 27, 2005 11 :45 AM
To: VTY_Engineering-Mechanical Structural; VTY .EFIN_DL
Subject: FW: Communication of Approved Engineering Standard

This is a new fleet standard for evaluation ot thinned wall piping components which will replace ENN-DC-133 ENN-I)C-133 will be superseded,
VY Department Procedure DP 0072, "Structural Evaluation of Thinned Wall Piping Components will be revised or superseded as required when ENN-DC-315 is adopted.

Use:
Entry Conditions for this Standard will be in ENN -DC-315 "Flow Accelerated Corrosion Program" and ENN-OC-185 "Through wall leaks in ASME Section XI Class 3 Moderate Energy Piping Systems". WPO has the responsibility to revise the references to ENN-DC-133 in these procedures.

Qualifications(frainil1q:
At present there is no ENN QUAL CARD for use of this Engineering Standard, Calculations performed using standard are documented per ENN-DC-126. Based on the scope of this standard, only Design Engineering - Civil! Structural personnel and the Mechanical types in EFIN with previous pipe stress experience have the charter and background to apply this standard.

Summary ot Changes from ENN-OC-133 as applioable to VY:

- More tormalized ties to ENN-OC-315, Wear rate determination for FAC program inspections is the responsibility oj the FAC Program Engineer
- Calculation of componel1t Wear, Wear Rate and Predicted Thickness is consistent the same as OP0072. The only change Jrom OPDOn is a reduction on the Safety Factor (SF) from 1.2 to 1.1.
- The methods used to calculate the code required thickness for pressure and moment loads are consistent with OPO()72, but presented in a different format.
- No significant changes to application oJ ASME Code Case N-513 for though wall leaks
- Added attachment for guidance in oatculation of component wear rates.
- Excel spreadsheet templates are available to facilitate calculations.

From: Ettlinger, Alan
sent: Monday, September 26, 2005 9:33 AM
To: Casella, Richard; Fitzpatrick, Jim; LO, Kai; Pace, Raymond
Cc: Unsal, Ahmet
Subject: Communication of Approved Engineering Standard

In accordance with EN-DC-146, as the Site Procedure Champion (SPC) at your site, please inJorm and communicate to applicable site personnel, the issuance of the following fleet NMM Engineering Standard.

ENN-CS-S-008, revision 0 Pipe Wall **Thinning** Structural Evaluation

ThiS standard supersedes ENN-DC-133. The standard can be accessed in IDEAS on the Citrix server.

The standard becomes effective, and will be posted on September 28, 2005.

If you have any questions, please give me a call,

Second victim dies of burns from power plant explosion

Milwaukee Sentinel, Mar 9, 1995 by BETSY THATCHER

- E-mail
- Print
- Link

A second victim of the Feb. 12 steam explosion at Wisconsin Electric Power Co.'s Pleasant Prairie plant died Tuesday.

WEPCO employee Gregory A. Schultz, of Waterford, died at St. Mary's Hospital in Milwaukee, where the 37-year-old operating supervisor was being treated for severe burns after a steam pipe ruptured at the Kenosha County power plant.

Schultz and another operating supervisor, Steven Baker, were performing a routine inspection of the plant when a 12-inch pipe that carries hot, pressurized water into the boiler of Unit 1 ruptured. Baker, 38, of Kenosha, died at the plant.

Schultz, who had worked for the company since 1978, received second- and third-degree burns over 60% of his body.

Related Results

"Words can't express the sorrow and regret we feel," WEPCO President Richard Grigg said in a statement. "We are remembering the Schultz and Baker families in our thoughts and prayers."

An investigation into the cause of the rupture is expected to be completed by the end of the week, company spokesmen said.

Preliminary results indicate there was substantial thinning of the pipe wall, which resulted in a break, a company statement said.

Employees of the Pleasant Prairie plant plan to buy a granite marker to place near a flagpole outside the plant in memory of the men.

NEC-UW_22

ISSUE 139: THINNING OF CARBON STEEL PIPING IN LWRs (REV. 1)

DESCRIPTION

Historical Background

This issue was raised[1089] as a result of a pipe rupture in the main feedwater (MFW) system at the Surry Unit 2 nuclear power plant on December 9, 1986. The MFW pipe rupture followed a reactor trip from full power shortly after the unit returned to operation on December 8, 1986, following a scheduled refueling outage. The staff presented briefings on the incident to the Commission on February 25, 1987, and to the ACRS at its 322nd Meeting on February 5, 1987.

The Surry pipe rupture was in the 18-inch "A" MFW pump suction line immediately downstream of a compound 90 elbow and T-section connecting the 18-inch pipe to the 24-inch condensate header. The rupture was a catastrophic, 360 circumferential break. A piece of the ruptured pipe (approximately 4 feet by 2 feet in size) was blown some distance from the break point. The piping still attached to the pump suction rotated away from the break point and came to rest against a portion of the "B" MFW pump discharge piping. No significant damage to the "B" MFW pump was noted.

The failed 18-inch suction line was fabricated from ASTM A-106 Grade B carbon steel and ASTM A-234 Grade WPB carbon steel wrought fittings with a nominal wall thickness of 0.5 inches. Visual inspections of the inside surface of the elbow revealed a dimpled surface and general pipe wall thinness as small as 0.05 inches. Ultrasonic thickness measurements indicated the wall-thinning to be a gradual change over most of the elbow fitting. The licensee concluded that the pipe ruptured because of the thinned wall and that the thinning was a result of erosion/corrosion.

On January 15, 1987, the Honorable Edward Markey (U.S. House of Representatives) requested the GAO to assess NRC actions following the Surry event and several other technical problems at nuclear power plants. The GAO assessment[1090] of actions taken related to the Surry event and similar piping deteriorations detected at other LWRs was issued in March 1988. The major GAO conclusions and recommendations are provided in the conclusion of this analysis.

A similar pipe rupture occurred at the Trojan plant following a reactor/turbine trip on March 9, 1985 (See LER 85002, Docket No. 5000344). The pipe rupture at the Trojan plant was in the 14-inch heater drain pump discharge line immediately downstream of a globe valve leading to the condensate header and MFW suction side. The piping was the same ASTM A-106 Grade B material with a required minimum wall thickness of 0.375 inches. The wall thickness in the region of the rupture was thinned to approximately 0.1 inches and the cause was attributed to wall-thinning by erosion/corrosion.

In both events, the fluid medium was single-phase, subcooled water at nominally 350F and 450 psi. Water velocities were in the range of 20 to 40 fps and the flow in the ruptured locations was subject to turbulence induced by piping and fitting configurations, with pressure increases resulting from automatic MFW isolation.

Historically, erosion/corrosion in nuclear and fossil plants has occurred primarily in wet steam (two-phase) lines and has not been reported in dry steam lines (EPRI NP-5410).[1092] The erosion/corrosion in single-phase (water) systems was not expected and differs in the mechanisms contributing to the process, being a complex phenomenon dependent on many variables such as alloy content, temperature, Ph, and flow velocities and perturbations caused by piping and fitting configurations.

Following the Surry event, the staff issued a series of Information Notices informing the industry of the Surry pipe rupture. On July 9, 1987, the staff issued NRC Bulletin No. 87-01[1093] requesting licensees to submit information concerning their programs for monitoring the thickness of pipe walls in high-energy, single- and two-phase, carbon steel piping systems.

Staff review of the licensees' responses to Bulletin 87-01[1093] were reported in SECY-88-50[1094] and Information Notice No. 88-17.[1095] A staff report on the status of the industry erosion/corrosion program was provided in SECY-88-50A.[1096] For two-phase, high-energy, carbon steel piping systems, responses indicated that licensees had programs at all plants for inspecting pipe wall-thinning. However, because the guidelines were not required to be implemented, the scope and extent of the programs varied significantly from plant to plant.

For single-phase piping systems such as in the feedwater/condensate lines, a limited number of inspections were conducted following the Surry event. Based on the Bulletin[1093] responses up to the time this issue was evaluated in November 1988, 23 out of a total of 110 units had not established an inspection program for the single-phase lines. Of these units, 17 were operating plants and 6 were under construction.

The staff review[1091] showed that wall-thinning in the feedwater/condensate systems was more prevalent in PWRs than in BWRs. The review indicated that licensees of 27 PWRs and 6 BWRs identified various degrees of wall-thinning in feedwater piping and fittings. The pipe wall-thinning problem was widespread for single- and two-phase, high-energy, carbon steel piping systems in PWR and BWR plants. Since the problem was more prevalent in PWRs, this analysis focused on PWR plants. However, due to the nature of the problem, the resolution indicated that the issue related to all LWRs.

Safety Significance

There were no requirements for the industry to have an inspection program for monitoring and examining the ASME minimum wall thickness for carbon steel piping. Therefore, even though a pipe break is a design basis event for which plants are designed, the potential frequency of such breaks was higher than previously anticipated. Lacking inspection requirements to provide assurance of the defense-in-depth against catastrophic pipe ruptures in the secondary power conversion systems (and specially the feedwater/condensate systems), plants may not have adequate assurance that they meet the design basis life.

The higher pipe rupture frequencies could also introduce additional challenges to safe plant shutdown from potential systems interactions of the high-energy steam/water releases that may damage, or affect, other systems (see "Systems Interactions from Pipe Ruptures" below). Thus, risks from design basis pipe ruptures that did not account for erosion/corrosion wall-thinning in the secondary piping systems may be greater than previously evaluated.

Possible Solution

The staff was continuing its review of pipe wall-thinning and was expected to assess the results obtained from inspections to be performed during the 1988 Spring refueling outages.[1094,1096] This assessment included visiting up to ten plants to review their inspection methods and results. The staff anticipated that its review would be completed by December 1988 and could, if necessary, provide the basis for new requirements[1094,1096] in single- and two-phase carbon steel piping systems.

A possible solution for the single-phase piping systems, which unlike the two-phase systems that have existing monitoring programs, might include inspections to be conducted at each refueling outage. However, for the long term solution, the staff planned to continue working with NUMARC and EPRI to arrive at an implementation program and schedule for the resolution of pipe wall-thinning in both single- and two-phase carbon steel piping systems.

PRIORITY DETERMINATION

Pipe ruptures from erosion/corrosion-induced wall-thinning of carbon steel piping had not been reported prevalent in dry-steam lines[1092] such as the main steam lines. Two-phase piping lines, such as the turbine crossover/under piping and steam extraction lines, had experienced erosion/corrosion wall-thinning and ruptures even though licensees had monitoring and inspection methods (though not required) in place to various degrees for some time. This indicated that improvements were needed in the existing inspection programs to provide timely detection of the piping degradations.

Single-phase carbon steel piping runs, which were not believed to be susceptible to erosion/corrosion wall-thinning, were not in general (prior to the Surry event) monitored or inspected for potential wall-thinning. The single-phase systems in the secondary power conversion systems which had been found to be susceptible to wall-thinning were the feedwater/condensate systems and the high pressure feedwater heater drain pump discharge piping lines. These single-phase

lines transport water at a nominal temperature of $350^{0}F$ and water velocities ranging from 20 to 40 fps. Both of these conditions tend to exacerbate the erosion/corrosion phenomenon in carbon steel piping systems carrying single-phase fluid (water).

AFW piping lines that typically draw water at lower temperatures from the condensate storage tank, and do not experience continuous flow during power production, had not been reported to be susceptible to erosion/corrosion wall-thinning. Because it was difficult to determine the effectiveness of the two-phase piping systems inspections, lacking information on previous repairs and replacements resulting from the inspections, the two-phase rupture frequency was assumed equivalent to the single-phase carbon steel piping rupture frequency estimated below. Without existing inspections, the two-phase piping systems would be expected to have a higher rupture frequency.

As stated above, this analysis focused on evaluating the carbon steel wall-thinning pipe ruptures in single-phase piping systems and the wall-thinning ruptures in two-phase piping systems of PWR power conversion systems. Based on existing inspection results, BWRs appeared to have a similar problem, but to a lesser degree. Therefore, this analysis bounded the issue for all LWRs.

Recovery of Power Conversion Systems

The power conversion systems feed into one another through various piping configurations, including straight lines or headers and various valving or fitting arrangements. Therefore, a rupture in either the single- or two-phase piping systems could disable the PWR power conversion systems to various degrees. Thus, the probability of recovering the power conversion systems was uncertain. Therefore, it was conservatively estimated that the probability of non-recovery of the power conversion systems (PCSNR) was 0.5, given a rupture in the secondary systems.

Carbon Steel Pipe Rupture Frequency

The data on erosion/corrosion-induced wall-thinning resulting in ruptures of carbon steel piping carrying single-phase fluid was limited to the Surry and Trojan events described earlier. This limited data was used to estimate upper and lower bounds of the subject pipe rupture frequency.

For the upper bound estimate, the plant-specific experiences of Surry and Trojan were used. At the Trojan plant, the pipe rupture occurred after approximately 9 years of operation. At the Surry plant, the pipe rupture occurred after approximately 14 years of operation. This data yielded an upper bound rupture frequency of 9×10^{-2}/RY. For the lower bound estimate, the two pipe ruptures were ratioed over the total number of PWR reactor-years of operation (approximately 600 RY). This yielded a lower bound estimate of 3.3×10^{-3}/RY.

The rupture frequency was approximated by a log normal distribution with an error factor of five and the upper and lower bounds were assumed as two symmetrically located percentiles (0.05 to 0.95) of a log normal distribution. The calculated mean rupture frequency was 3×10^{-2}/RY. As stated earlier, it was assumed that the rupture frequency of 3×10^{-2}/RY was applicable to the secondary side carbon steel piping systems identified herein.

Most of the pipe ruptures that might occur in the non-safety-related portions of the secondary systems are likely to be outside of containment because most (90%) of the secondary side piping is located outside containment. Pipe ruptures in the safety-related portion of the MFW piping inside containment can result in the secondary side of the affected steam generator blowing down to the containment atmosphere. For these lower frequency ruptures, $(0.1)(3 \times 10^{-2}) = 3 \times 10^{-3}$/RY, isolation of AFW to the affected steam generator will reduce the chance of containment overpressurization from continued long-term steaming due to decay heat from the reactor core. Automatic AFW isolation is necessary to ensure that the containment design pressure will not be exceeded. This event, like other ruptures that may occur in the PWR power conversion systems, was treated as a total loss of main feedwater. This sequence was bounded by the TMLU rupture event sequence described below. However, pipe ruptures inside containment are less likely and will not likely induce the negative systems interaction problems that can result from pipe ruptures outside containment.

Systems Interactions from Pipe Ruptures

Communication Systems Failures: During the MFW pipe rupture at the Surry plant,

the Cardox and Halon fire suppression systems were actuated by steam/water intrusion into their control panels. The security repeater which was located approximately five feet from a Cardox discharge nozzle failed and was later found to be covered with a thick layer of ice. As a result, security communications were temporarily limited to the non-repeater hand-held radios. Therefore, actuation of the Surry fire protection system (FPS) resulted in loss of a train of the communication systems.

Given that loss of one train of plant communications occurred in one of the two pipe rupture events, the probability that failure of this train of communication can occur as a result of pipe ruptures in the secondary systems outside containment was estimated to be 0.5.

To estimate the probability of loss of the backup hand-held communication radios, the following were assumed: probability of battery failure = 0.1; probability of operator error in not replacing the batteries = 0.1; and probability that other units are not readily available = 0.1. The probability of loss of both communication systems, given a pipe rupture in the secondary systems outside containment, was estimated to be 5×10^{-4}.

To estimate the impact of the loss of plant communication systems, it was assumed that loss of communications would increase operator errors in the four event sequences affected by the pipe rupture. Based on an examination of the fault trees[54] for the four sequences, and adjusting the operator errors to account for loss of communications, the percentage increase in core-melt frequency for each sequence was estimated as follows:

Loss of Communications

Sequence	% Increase In Sequence Core-Melt Frequency
TMQH	7
TMKU	negligible
TML(PCSNR)U	7
TMQD	2

Actuation of FPS: Within minutes of the MFW pipe rupture at Surry, 62 sprinkler heads opened in the immediate area of the rupture. As a result of the sprinkler water and the feedwater discharge, the Cardox and Halon suppression systems control panels were affected by intrusion of steam/water. The intrusion caused the time limit, battery charger, and the dual zone modules to short. Thus, the manual remote actuation circuit located in the control room was affected.

In Issue 57, the effects of actuation of the FPS actuation and the potential increases to core-melt frequency were estimated; the sequence evaluated was the TMLU sequence and the safety system evaluated was the AFW system. Because one of the two pipe rupture events (Surry and Trojan) affected the FPS manual remote control, the estimates in Issue 57 were adjusted by assigning a probability of 0.5 to failure of the FPS manual control. With this adjustment, the increase in unavailability of the AFW system, given actuation of the FPS water deluge system, was estimated to be 2×10^{-5}. Assuming typical AFW unavailability of 5×10^{-5} (discussed later), the combined AFW unavailability, given actuation of the FPS, was 7×10^{-5}.

Using the same 2×10^{-5} increased unavailability for other safety systems in the event sequences of this issue, no significant effect was found because the other safety systems were less sensitive to the 2×10^{-5} estimate. This conclusion was consistent with the Issue 57 assessment.

Electric Door Lock Failures: At the time of the Surry pipe rupture event, water and steam saturated a security card-reader located approximately 50 feet from the break point. As a result, key-cards would not open plant doors. The control room doors were opened to provide access to the control room and security personnel were assigned to the control room to provide the access security. One operator was temporarily trapped in a stairway due to the card-reader failure. At the time of this evaluation, the Surry plant was considering installing electric override switches to remedy this problem.

In Issue 81, the impact of the electric lock (card-reader) failure at Surry was evaluated. The results from Issue 81 indicated that failure of electric locks, without override protection, may contribute approximately 2% to core-melt accidents from pipe ruptures outside containment.

Frequency Estimate

To estimate the core-melt frequency from ruptures in PWR secondary systems, an example PRA[54] was used together with additional information provided in NUREG/CR-2800.[64] The pertinent accident sequences were then adjusted to account for pipe ruptures in the secondary side of PWR plants. The accident sequences used in this analysis were TMQD, TMKU, TMQH, and TML(PCSNR)L where:

TM -	a loss of power conversion system (PCS) transient caused by other than loss-of-offsite power. For this analysis, TM corresponds to the secondary system pipe rupture frequency (3×10^{-2}/RY) resulting in loss of the main feedwater system (M = 1);
Q -	the pressurizer safety/relief valve demanded opens (0.01) and any pressurizer safety/relief valve fails to re-close (0.05);
D -	failure to provide sufficient ECCS injection (10^{-3});
K -	failure of the RPS (2.6×10^{-5});
H -	failure of the ECCS recirculation system (7×10^{-3});
PCSNR -	failure to recover the PCS (0.5, as discussed earlier);
U -	failure of the operator to start high pressure injection, or feed-and-bleed is initiated, but is unsuccessful. For this analysis, U = 0.2 was assumed;
L -	failure of the AFW system. For 3-train AFW system plants, a typical AFW unavailability was 1.8×10^{-5} /demand. For 2-train AFW system plants, the goal of Issue 124 was to upgrade the AFW systems to 10^{-4}/demand. Therefore, a typical value of 5×10^{-5}/demand was used in this analysis.

Table 3.139-1 includes the sequences with and without the effects of systems interactions from pipe ruptures in the secondary systems outside of containment.

Examination of the results indicate that collectively the systems interactions may increase the core-melt frequency from pipe ruptures in the secondary systems outside containment by approximately 20% (9×10^{-8}/RY). The total core-melt frequency, with the systems interactions (SI) effects included, was estimated to be 5×10^{-7}/RY.

TABLE 3.139-1

Sequence	Without (SI)	Communications (SI)	FPS (SI)	Locked Doors (SI)	TOTAL
TMQD	1.50×10^{-8}	3.00×10^{-10}	neg.	3.0×10^{-10}	1.56×10^{-8}
TMKU	1.50×10^{-7}	neg.	neg.	3.0×10^{-9}	1.53×10^{-7}
TMQH	1.05×10^{-7}	7.40×10^{-9}	neg.	2.1×10^{-9}	1.15×10^{-7}
TMLU	1.50×10^{-7}	1.05×10^{-8}	6×10^{-8}	3.0×10^{-9}	2.24×10^{-7}
SUM	4.20×10^{-7}	1.80×10^{-8}	6×10^{-8}	8.4×10^{-9}	5.00×10^{-7}

Consequence Estimate

The core-melt sequences under consideration involve no large breaks initially in the reactor coolant system pressure boundary. The reactor is likely to be at high pressure until the core melts through the lower vessel head with a steady discharge of steam and gases through the PORV(s). These are conditions that may produce significant H_2 generation and combustion.

For these sequences, a 3% probability of containment failure due to H_2 burn and a 1% probability of containment isolation failure were used. If the containment does not fail by H_2 burn or isolation failure, it was assumed to fail by basemat melt-through.

The conditional releases for these containment failure modes had a weighted average core-melt release of 1.7×10^{5} man-rem. The calculated releases were based on a core inventory typical of a 1120 MWe plant, a uniform population density of 340 persons per square mile from an exclusion area of one-half mile out to a 50-mile radius from the plant, no evacuation of people, no injestion pathways, and meteorology typical of a midwest site.

The annual public risk from secondary side piping ruptures due to wall-thinning was the product of the core-melt frequency (5×10^{-7}/RY) and the weighted average

release (1.7×10^{-5} man-rem). Therefore, the public risk was 8.5×10^{-2} man-rem /RY. Assuming a remaining plant life of 30 years, the cumulative public risk was 3 man-rem/reactor.

Cost Estimate

Industry Cost: A possible solution for early detection of wall-thinning in carbon steel piping in the secondary systems was to implement and conduct inspection programs for these systems during each refueling outage. A report was prepared by EPRI[1092] to provide guidance to the industry for conducting NDE of ferritic piping systems for wall-thinning caused by erosion/corrosion in nuclear and fossil power plants. The EPRI report contained the results of investigations of various NDE methods that may be applicable to the detection of erosion/corrosion effects. EPRI reported that virtually all plants used manual ultrasonic thickness measurements. Four utilities had performed automated ultrasonic thickness measurements from the outside surface of the piping. One EPRI source reported that an automated examination would cost approximately $50,000 and take one week, whereas a manual team of two operators could perform the examination in one afternoon. Therefore, the cost of the manual inspection was estimated to be $10,000 per outage.

The difference noted by EPRI was that the manual team would acquire data on a 4-inch grid pattern and the automated system could acquire data continuously over the entire surface. Additional setup time was also required for the automated system. Therefore, the above $10,000 cost for the manual inspection could have been overestimated.

An additional cost associated with the inspections was the removal and disposal of asbestos insulation and re-insulation. These costs were reported to range from $300,000 to $750,000 per outage. In some plants, asbestos insulation was programatically being removed due to strict state and local guidelines associated with health hazards to workers from asbestos.

Approximately half (44) of the 92 plants contacted in the EPRI survey had asbestos insulation. Thirty-two of the forty-four had at least partially replaced asbestos with other insulation, or were planning to remove the asbestos, and the remaining twelve plants were undecided.

Based on the above, any NRC requirement to conduct NDE inspections at each refueling outage could provide an additional incentive for the 12 plants (13% of all plants) to remove and replace the asbestos insulation with other types of insulation. Therefore, on an average, the industry costs to remove and dispose of the asbestos insulation to facilitate NDE inspections was estimated to be a one-time cost of (0.13)($750,000 + $300,000)/2 = $68,000/plant. However, the argument could be made that the cost of asbestos removal could be driven by the state and local requirements, and not by NRC inspection requirements.

Assuming a remaining plant life of 30 years and a typical time between refueling outages of 1.5 years, the cumulative number of inspections that may be conducted during each refueling outage for each plant was 20. The annual cost over 30 years was (20)($10,000)/30 = $6,700/plant. The present value of the NDE annual costs over 30 years, considering a 5% discount rate, was approximately $100,000/plant. The combined one-time costs for asbestos insulation removal and disposal and the sent value NDE cost over 30 years is $168,000/plant.

NRC Cost: It was estimated that one man-year of effort may be needed to reach a staff position on this issue and an additional man-year of effort to develop a Regulatory Guide or SRP Section. Assuming $100,000/man-year, the NRC costs were

estimated to be $200,000. When distributed over approximately 100 plants, this cost was $2,000/plant.

Total Cost: The combined industry and NRC cost for the possible solution was estimated to be $170,000/plant.

Value/Impact Assessment

Based on the estimated risk reduction of 3 man-rem/reactor and implementation costs of $170,000/plant for the possible solution (NDE examinations at each plant refueling outage), the value/impact score was given by:

$$S = \frac{3\,\text{man-rem}}{\$0.17\text{M}}$$
$$= 17.6\,\text{man-rem}/\$\text{M}$$

Other Considerations

Accident Avoidance Cost: The present value of onsite property damage conditional on a core-melt for a remaining plant life of 30 years, assuming a 5% discount rate, was $20 billion. For a core-melt frequency of 5×10^{-7}/RY attributed to pipe ruptures in the secondary systems, the accident avoidance cost by eliminating or significantly reducing the probability of pipe ruptures was $10,000/plant.

Industry Rupture Avoidance Cost: The rupture avoidance costs are the plant costs estimated to result from a pipe rupture in the secondary systems, assuming the plant responds as designed and no core-melt from potential equipment failures ensues. For a pipe rupture frequency of 3×10^{-2}/RY, the chance of a pipe rupture in the secondary side can approach unity over the life of a plant.

To estimate the costs of plant repairs after a forced outage from a pipe rupture in the secondary system, historical plant operational data indicates that a best estimate repair cost from forced outages for a typical nuclear power plant is approximately $1,000/hour.[1082] The Trojan plant outage time following a pipe rupture in the secondary system was 6 days, whereas the Surry plant outage time lasted approximately 90 days. Based on the above, the plant repair costs from these two events was estimated to range from $140,000 to $2M. The replacement power costs resulting from the forced outages of 6 days for the Trojan plant and 90 days for the Surry plant were $3M and $45M, respectively; the cost of replacement power was estimated at $500,000/day.

It was assumed that the above cost estimates reflected lower and upper bound costs that could be represented by a log normal distribution with an error factor of 4. The combined repair costs and replacement power costs, adapted to a log normal distribution, yielded an estimated value of $17M as the mean plant costs resulting from a pipe rupture in the secondary systems.

The $10,000/plant accident (core-melt) avoidance costs were small compared to the estimated rupture avoidance costs of

$17M/plant. The low core-melt frequency of 5×10^{-7}/RY drove down the accident avoidance costs. However, based on the estimated pipe rupture frequency of 3×10^{-2}/RY, the chance of a pipe rupture in the secondary systems over the life of a plant approaches unity. Thus, the rupture avoidance costs dominated the combined accident and rupture avoidance costs.

When the implementation cost ($170,000/plant) is offset by the accident and rupture avoidance costs (a $17M/plant cost savings), the denominator of S becomes negative. The negative denominator of approximately $17M/plant indicates a substantial potential cost savings (industry incentive) by avoiding piping ruptures in the secondary systems.

Occupational Safety: Erosion/corrosion-induced ruptures in high energy carbon steel piping lines described in this analysis resulted in injury and fatalities to plant personnel and contractor employees working in the area of the ruptures. At the time of the Surry pipe rupture, 8 contractor employees were working in the area of the pipe rupture; 6 of these individuals were hospitilized for treatment of severe burns and 2 were treated at a clinic and released. Four of the severely burned individuals died and the other two were in serious to critical condition. One of the two remained in serious condition for more than a month after the accident. Following the pipe rupture at the Trojan plant, one member of the plant operating staff received first and second degree burns and was treated at a local hospital over a three-week period.

CONCLUSION

The estimated core-melt frequency of 5×10^{-7}/RY and the potential risk reduction of 3 man-rem/reactor indicated that pipe ruptures in the PWR secondary systems from erosion/corrosion-induced wall-thinning is of low safety significance to the public. Since inspection results indicated that erosion/corrosion wall-thinning of carbon steel piping is less prevalent in BWR plants, the above PWR risk estimates should be bounding. Therefore, as a generic safety issue, this issue would have been given a low priority ranking. However, the erosion/corrosion-induced wall-thinning of carbon steel piping in secondary systems was not expected to be a significant cause of pipe ruptures. Pipe ruptures were more generalized as limiting faults: postulated, but not expected to occur. Thus, knowledge and an understanding of this phenomena was limited. This analysis indicated that, without adequate defensive methods or measures, pipe rupture induced by wall-thinning can be expected within the lifetime of a plant: an infrequent event with a higher frequency than the limiting fault (postulated) pipe ruptures.

The GAO concluded that the Surry accident initiated a new era of understanding regarding erosion/corrosion at nuclear power plants and demonstrated that unchecked erosion/corrosion can lead to a fatal accident. The GAO also concluded that NRC needed a mechanism to ensure that utilities periodically assess the integrity of piping systems to reduce the risk of future injury to plant personnel or damage to equipment caused by erosion/corrosion. The GAO recommended that NRC require utilities to:

(1) inspect all nuclear plants to develop data regarding the extent that erosion/corrosion existed in piping systems, including straight sections of pipe;

(2) replace piping that did not meet the industry's minimum allowable thickness standards; and

(3) periodically monitor piping systems and use the data developed during these inspections to monitor the spread of erosion/corrosion in the plants.

Based on the potential low public risk, the NRC need (References 1090, 1094, 1096) to establish a new position or requirement on the previously unexpected phenomena, and a significant industry cost incentive to address and resolve the issue, this issue was classified as a Regulatory Impact issue by RES consistent with the ongoing levels of staff and industry actions described in SECY-88-50[1094] and SECY-88-50A.[1096] However, NRR considered the issue to be resolved based on: (1) guidelines on erosion/corrosion in single-phase piping, as developed by NUMARC and found acceptable by the staff; (2) participation in a timely way by all 113 operating LWR plants; (3) acceptable analytical procedures for the evaluation and selection of piping to be inspected; (4) replacement of components as needed; and (5) a long-term as well as a short-term program for continuing evaluation and inspection of both single-phase and two-phase piping.[1132]