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 scop
cense renewal as specified ir
graphs (a) (1)-(3) of this section.

[60 FR 22491, May 8, 1995, as amend
FR 65175, Dec. 11, 1996; 64 FR 72002,
1999]

§ 54.5 Interpretations.

Except as specifically author
the Commission in writing, nc
pretation of the meaning of the
tions in this part by any officer
ployee of the Commission other
written interpretation by the
Counsel will be recognized to b
ing upon the Commission.

§ 54.7 Written communications.

All applications, corresponde
ports, and other written com
tions shall be filed in accordar
applicable portions of 10 CFR 50

§ 54.9 Information collection ments: OMB approval.

(a) The Nuclear Regulatory (
sion has submitted the info
collection requirements conta
this part to the Office of Man
and Budget (OMB) for approva
quired by the Paperwork R
Act (44 U.S.C. 3501, et seq.). T
may not conduct or sponsor, a
son is not required to respond
lection of information unless
plays a currently valid OMB
number. OMB has approved t
mation collection requireme
tained in this part under cont
ber 3150–0155.

(b) The approved informatio
tion requirements contained
part appear in §§ 54.13, 54.17, 54
54.22, 54.23, 54.33, and 54.37.

[60 FR 22491, May 8, 1995, as ame
FR 52188, Oct. 6, 1997]

§ 54.11 Public inspection of tions.

Applications and docume
mitted to the Commission ir
tion with renewal application
made available for public insp
accordance with the provisio
regulations contained in 10 Cl

additional systems, structures, and components should be included in an individual plant's technical specifications. However, the Commission can conclude that these additional systems, structures, and components are of a relatively lower safety significance because they are, by exclusion, nonsafety-related systems, structures, and components whose failure cannot prevent the performance or reduce the availability of a safety-related system, structure, or component. Additionally, the Commission believes that the existing regulatory process for these additional nonsafety-related systems, structures, and components is adequate to ensure that age degradation will not result in a loss of functionality in accordance with the CLB.

The Commission believes that there is sufficient experience with its policy on technical specifications to apply that policy generically in revising the license renewal rule consistent with the Commission's desire to credit existing regulatory programs. Therefore, the Commission concludes that the technical specification limiting conditions for operation scoping category is unwarranted and has deleted the requirement that identifies systems, structures, and components with operability requirements in technical specifications as being within the scope of the license renewal review.

(ii) Intended Function

The previous license renewal rule required an applicant for license renewal to identify, from systems, structures, and components important to license renewal, those structures and components that contribute to the performance of a "required function" or could, if they fail, prevent systems, structures, and components from performing a "required function." This requirement initially posed some difficulty in conducting pre-application reviews of proposed scoping methodologies because it was not clear what was meant by "required function." Most systems, structures, and components have more than one function and each could be regarded as "required." Although the Commission could have required a licensee to ensure all functions of a system, structure, or component as part of the aging management review, the Commission concluded that this requirement would be unreasonable and inconsistent with the Commission's original intent to focus only on those systems, structures, and components of primary importance to safety. Consideration of ancillary functions would expand the scope of the license renewal review beyond the Commission's intent. Therefore, the Commission determined that "required function" in the previous license renewal rule refers to those functions that are responsible for causing the systems, structures, and components to be considered important to license renewal.

To avoid any confusion with the previous rule, the Commission has changed the term "required function" to "intended function" and explicitly stated in § 54.4 that the intended functions for systems, structures, and components are the same functions that define the systems, structures, and components as being within the scope of the final rule.

(iii) Bounding the Scope of Review

Pre-application rule implementation has indicated that the description of systems, structures, and components subject to review for license renewal could be broadly interpreted and result in an unnecessary expansion of the review. To limit this possibility for the scoping category relating to nonsafety-related systems, structures, and components, the Commission intends this nonsafety-related category (§ 54.4(a)(2)) to apply to systems, structures, and components whose failure would prevent the accomplishment of an intended function of a safety-related system, structure, and component. An applicant for license renewal should rely on the plant's CLB, actual plant-specific experience, industry-wide operating experience, as appropriate, and existing engineering evaluations to determine those nonsafety-related systems, structures, and components that are the initial focus of the license renewal review. Consideration of hypothetical failures that could result from system interdependencies that are not part of the CLB and that have not been previously experienced is not required.

Likewise, to limit the potential for unnecessary expansion of the review for the scoping category concerning those systems, structures, and components whose function is relied upon in certain plant safety analyses to demonstrate compliance with the Commission regulations (i.e., environmental qualification, station blackout, anticipated transient without scram, pressurized thermal shock, and fire protection), the Commission intends that this scoping category include all systems, structures, and components whose function is relied upon to demonstrate compliance with these Commission's regulations. An applicant for license renewal should rely on the plant's current licensing bases, 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. Consideration of hypothetical failures that could result from system interdependencies, that are not part of the current licensing bases and that have not been previously experienced is not required.

Several commenters noted that the word "directly" did not precede the phrase "prevent satisfactory accomplishment of any of the functions identified in paragraphs (a)(1)(i), (ii), or (iii) of this section" in § 54.4(a)(2) and concluded that, in the absence of the word "directly," the license renewal review could cascade into a review of second-, third-, or fourth-level support systems. The Commission reaffirms its position that consideration of hypothetical failures that could result from system interdependencies that *are not part of the CLB* and that have not been previously experienced is not required. However, for some license renewal applicants, the Commission cannot exclude the possibility that hypothetical failures that *are part of the CLB* may require consideration of second-, third-, or fourth-level support systems. In these cases the word "directly" may cause additional confusion, not clarity, regarding the systems, structures and components required to be within the scope of license renewal. In removing the word "directly" from this scoping criterion, the Commission believes it has (1) achieved greater consistency between the scope of the license renewal rule and the scope of the maintenance rule (§ 50.65) regarding nonsafety-related systems whose failure could prevent satisfactory accomplishment of safety-related functions and thus (2) promoted greater efficiency and predictability in the license renewal scoping process.

The inclusion of nonsafety-related systems, structures, and components whose failure could prevent other systems, structures, and components from accomplishing a safety function is intended to provide protection against safety function failure in cases where the safety-related structure or component is not itself impaired by age-related degradation but is vulnerable to failure from the failure of another structure or component that may be so impaired. Although it may be considered outside the scope of the maintenance rule, the Commission intends to include equipment that is not seismically qualified located near seismically qualified equipment (i.e

Seismic II/I equipment already identified in a plant CLB) in this set of nonsafety-related systems, structures and components.

In one of its comments, the Sierra Club indicated that all nonsafety-related equipment and required functions should be considered because failures could go unnoticed for a long period of time and start a chain reaction that could lead to catastrophic events. Nevada also proposed a fuel life-cycle approach to license renewal that would consider the plant operations as an "Integrated Operating System." The Commission disagrees with the Sierra Club comment and the Commission concludes that the license renewal approach proposed by Nevada would result in the consideration of issues outside the scope of this rule and result in consideration of additional systems, structures, and components that are not directly related to the safe operation of the plant for the period of extended operation. The Commission has reviewed its scoping criteria and determined that the criteria (1) reflect an appropriate consideration of the existing regulatory process, (2) properly focus the initial license renewal review on those systems, structures, and components that are most important to safety and (3) will not result in an unwarranted re-examination of the entire plant.

One commenter indicated that the scope of systems, structures, and components considered for license renewal could be further reduced by identifying and addressing the very few issues in which a plant's design must specifically consider 40 years of degradation. In one of its comments, Illinois suggested that those systems, structures and components required to mitigate a sequence leading to core damage, as determined by plant-specific probabilistic analyses, and those systems, structures, and components required to make protective action recommendations for the protection of the public, should also be included in the scope of this rulemaking.

As the commenter suggested, the Commission did consider further limiting the scope of license renewal to certain issues in a plant's design that were specifically based on a time period bounded by the current license term (40 years). As a result, the Commission explicitly identified the need to review time-limited aging analyses and incorporated this requirement into the final rule. However, as discussed in Section III.d and III.f of this SOC, the Commission determined that, at this time, there was not an adequate basis to generically exclude passive, long-lived structures and components from an aging management review. Therefore, the Commission believes it is inappropriate to further reduce the systems, structures, and components within the scope of license renewal.

Regarding the use of probabilistic analyses in the license renewal scoping process, a separate Section III.c(iv) has been added to the SOC, to discuss the role of probabilistic risk assessment in license renewal. Regarding systems, structures, and components required to make protective action recommendations, the Commission thoroughly evaluated emergency planning considerations in the previous license renewal rulemaking. These evaluations and conclusions are still valid and can be found in the SOC for the previous license renewal rule (56 FR 64943 at 64966). Therefore, the Commission concludes that systems, structures, and components required for emergency planning, unless they meet the scoping criteria in § 54.4, should not be the focus of a license renewal review.

(iv) Use of Probabilistic Risk Assessment in License Renewal

Several comments from Illinois concerned the use of probabilistic analysis techniques in the license renewal process. Illinois indicated that the NRC should require rigorous probabilistic analyses, require these analyses to be used in appropriate regulatory applications, and require these probabilistic analyses to be updated, as needed. In addition, Illinois noted that the previous rule and the proposed rule did not require consideration of individual plant examination (IPE) results.

The Commission is finalizing a policy statement regarding the increased use of probabilistic risk assessment (PRA) methods in nuclear regulatory activities (59 FR 63389; December 8, 1994). However, there is currently no additional guidance for licensees to conduct more rigorous probabilistic analyses beyond the guidance for an IPE and an IPE External Events (IPEEE) (Generic Letter 88–20). The Commission's consideration of regulatory requirements associated with developing, maintaining, or using probabilistic analyses is beyond the scope of this rulemaking.

The CLB for currently operating plants is largely based on deterministic engineering criteria. Consequently, there is considerable logic in establishing license renewal scoping criteria that recognize the deterministic nature of a plant's licensing basis. Without the necessary regulatory requirements and appropriate controls for plant-specific PRAs, the Commission concludes that it is inappropriate to establish a license renewal scoping criterion, as suggested by Illinois, that relies on plant-specific probabilistic analyses. Therefore, within the construct of the final rule, PRA techniques are of very limited use for license renewal scoping.

In license renewal, probabilistic methods may be most useful, on a plant-specific basis, in helping to assess the relative importance of structures and components that are subject to an aging management review by helping to draw attention to specific vulnerabilities (e.g. results of an IPE or IPEEE). Probabilistic arguments may assist in developing an approach for aging management adequacy. However, probabilistic arguments alone will not be an acceptable basis for concluding that, for those structures and components subject to an aging management review, the effects of aging will be adequately managed in the period of extended operation.

Illinois also indicated that as probabilistic insights are more fully integrated with our traditional deterministic methods of regulation, they may define a narrower safety focus. Thus, the use of probabilistic insights could reduce the scope of the very programs that the license renewal rule credits for monitoring and identifying the effects of aging.

The Commission reaffirms its previous conclusion (see 56 FR 64943 at 64956) that PRA techniques are most valuable when they focus the traditional, deterministic-based regulations and support the defense-in-depth philosophy. In this regard, PRA methods and techniques would focus regulations and programs on those items most important to safety by eliminating unnecessary conservatism or by supporting additional regulatory requirements. PRA insights would be used to more clearly define a proper safety focus, which may be narrower or may be broader. In any case, PRA will not be used to justify poor performance in aging management or to reduce regulatory or programmatic requirements to the extent that the implementation of the regulation or program is no longer adequate to credit for monitoring or identifying the effects of aging.

d. The Regulatory Process and Aging Management

(i) Aging Mechanisms and Effects of Aging

The license renewal review approach discussed in the SOC accompanying the December 13, 1991, rule emphasized the dent containment heat removal, or (3) postaccident containment atmosphere cleanup (e.g., hydrogen removal system).

d. Systems[1] or portions of systems that are required for (1) reactor shutdown, (2) residual heat removal, or (3) cooling the spent fuel storage pool.

e. Those portions of the steam systems of boiling water reactors extending from the outermost containment isolation valve up to but not including the turbine stop valve, and connected piping of 2½ inches or larger nominal pipe size up to and including the first valve that is either normally closed or capable of automatic closure during all modes of normal reactor operation. The turbine stop valve should be designed to withstand the SSE and maintain its integrity.

f. Those portions of the steam and feedwater systems of pressurized water reactors extending from and including the secondary side of steam generators up to and including the outermost containment isolation valves, and connected piping of 2½ inches or larger nominal pipe size up to and including the first valve (including a safety or relief valve) that is either normally closed or capable of automatic closure during all modes of normal reactor operation.

g. Cooling water, component cooling, and auxiliary feedwater systems[1] or portions of these systems, including the intake structures, that are required for (1) emergency core cooling, (2) postaccident containment heat removal, (3) postaccident containment atmosphere cleanup, (4) residual heat removal from the reactor, or (5) cooling the spent fuel storage pool.

h. Cooling water and seal water systems[1] or portions of these systems that are required for functioning of reactor coolant system components important to safety, such as reactor coolant pumps.

i. Systems[1] or portions of systems that are required to supply fuel for emergency equipment.

j. All electric and mechanical devices and circuitry between the process and the input terminals of the actuator systems involved in generating signals that initiate protective action.

k. Systems[1] or portions of systems that are required for (1) monitoring of systems important to safety and (2) actuation of systems important to safety.

l. The spent fuel storage pool structure, including the fuel racks.

m. The reactivity control systems, e.g., control rods, control rod drives and boron injection system.

n. The control room, including its associated equipment and all equipment needed to maintain the control room within safe habitability limits for personnel and safe environmental limits for vital equipment.

o. Primary and secondary reactor containment.

p. Systems,[1] other than radioactive waste management systems,[2] not covered by items 1.a through 1.o above that contain or may contain radioactive material and whose postulated failure would result in conservatively calculated potential offsite doses (using meteorology as recommended in Regulatory Guide 1.3, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss of Coolant Accident for Boiling Water Reactors," and Regulatory Guide 1.4, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss of Coolant Accident for Pressurized Water Reactors") that are more than 0.5 rem to the whole body or its equivalent to any part of the body.

q. The Class 1E electric systems, including the auxiliary systems for the onsite electric power supplies, that provide the emergency electric power needed for functioning of plant features included in items 1.a through 1.p above.

2. Those portions of structures, systems, or components whose continued function is not required but whose failure could reduce the functioning of any plant feature included in items 1.a through 1.q above to an unacceptable safety level or could result in incapacitating injury to occupants of the control room should be designed and constructed so that the SSE would not cause such failure.[3]

3. Seismic Category I design requirements should extend to the first seismic restraint beyond the defined boundaries. Those portions of structures, systems, or components that form interfaces between Seismic Category I and non-Seismic Category I features should be designed to Seismic Category I requirements.

4. The pertinent quality assurance requirements of Appendix B to 10 CFR Part 50 should be applied to all activities affecting the safety-related functions of those portions of structures, systems, and components covered under Regulatory Positions 2 and 3 above.

[2] Specific guidance on seismic requirements for radioactive waste management systems is under development.

[3] Wherever practical, structures and equipment whose failure could possibly cause such injuries should be relocated or separated to the extent required to eliminate this possibility.

Summary of Previously Identified Pipe Wall Thinning Issues and Events

Date	Site	Details	Ref.
1976	Oconee 3	Pinhole leak in an extraction steam line. A surveillance program utilizing ultrasonic examination of extraction steam lines was initiated and, in 1980, identified two degraded elbows identical to the Unit 2 elbow that subsequently failed in 1982. The elbows were replaced.	IN 82-22
1981	Millstone 2	Use of engineering personnel unfamiliar with plant operating conditions, plant as-built designs, or erosion/corrosion history.	IN 93-21
January 1982	Vermont Yankee	Licensee shut down the plant after identifying steam blowing from a leak in the 12-inch-diameter drain line between a moisture separator and heater drain tank.	IN 82-22
January 1982	Trojan	Steam line failure resulting in plant shutdown.	IN 82-22
February 1982	Zion 1	Steam leak in 150 psig high-pressure exhaust steam line originating from an 8-inch crack on a weld joining 24-inch piping with the 37.5-inch high-pressure steam exhaust piping leading to the moisture separator reheater. The event resulted in plant shutdown	IN 82-22
June 1982	Oconee 2	While operating at 95-percent power, a 4-square-foot rupture occurred in a 24-inch-diameter long-radius elbow in a feedwater heat extraction line. The reactor was manually tripped, a steam jet destroyed a non-safety-related load center and certain non-safety-related instrumentation. Personnel were hospitalized overnight with steam burns. An ultrasonic inspection had identified substantial erosion of the elbow In March 1982, but the erosion failed to meet the licensee's criteria for rejection.	IN 82-22
June 1982	Browns Ferry 1	Steam line failure resulting in plant shutdown.	IN 82-22
March 1983	Dresden 3	Steam leak from the shell side of the 3C3 low-pressure feedwater heater near the extraction steam inlet nozzle. The leak was attributed to erosion by deflected extraction steam. The feedwater heaters had not been included in a periodic inspection program.	IN 99-19
March 1985	Haddam Neck	Pipe rupture, approximately ½-by-2-1/4-inch, downstream of a normal level control valve for a feedwater heater.	GL 89-08

Date	Site	Details	Ref.
December 1986	Surry 2	Catastrophic failure of 18-inch MFW pump suction line elbow when a main steam isolation valve failed closed on one of the steam generators. A 2-by-4-foot section of the elbow was blown out and came to rest on an overhead cable tray. The reactive force completely severed the suction line. The free end whipped and came to rest against the discharge line for another pump. The failure of the piping, which was carrying single-phase fluid, was caused by erosion/corrosion of the carbon steel pipe wall. The unit had been operating at full power. An automatic plant trip occurred and four workers suffered fatal injuries. Released steam caused the fire suppression system to actuate, releasing halon and carbon dioxide into emergency switchgear. The NRC dispatched an augmented inspection team to the site.	IN 86-106 Bul-letin 87-01 IN 88-17 GL 89-08
June 1987	Trojan	MFW degradation was discovered by the licensee in at least two areas of the straight sections of ASME Class 2 safety-related MFW piping inside containment. The thinning was discovered when the Trojan steam piping inspection program was expanded to include single-phase piping. The thinning was attributed to high fluid flow velocities and other operating factors.	IN 87-36 IN 88-17 GL 89-08
December 1987	LaSalle 1	Throughwall pinhole leaks due to erosion were discovered in a 45-degree elbow down stream of a turbine-driven reactor feedwater pump minimum-flow control valve. Subsequent inspections identified additional areas of wall thinning.	IN 88-17
Septem-ber 1988	Surry 2	The pipe wall of an elbow installed on the suction side of a MFW pump during a 1987 refueling outage was discovered to have thinned more rapidly than expected, losing 20 percent of its 0.500-inch wall thickness in 1.2 years. Wall thinning was also observed in safety-related MFW piping and in other non-safety-related condensate piping.	GL 89-08
December 1988	Brunswick 1	Inspection indicated areas of significant but localized erosion on the internal surfaces of several carbon steel valve bodies. The affected safety-related valves were the 24-inch residual heat removal/low pressure core injection (RHR/LPCI) system injection and 16-inch suppression pool isolation valves.	IN 89-01

Date	Site	Details	Ref.
April 1989	Arkansas Nuclear One Unit 2	Steam escaping from a ruptured 14-inch high-pressure steam extraction line caused a spurious turbine/reactor trip from 100-percent power. This straight run of piping terminates at an elbow that was replaced during the previous outage because of erosion-induced wall thinning. The pipe and those of similar geometries had not been included in the licensee's surveillance samples, and the degraded condition was not detected during the elbow replacement.	IN 89-53
March 1990	Surry 1	Rupture of a straight section of piping downstream of a level control valve in the low-pressure heater drain (LPHD) system. The LPHD system was included in the licensee's FAC program at the time, but the program did not provide an inspection for the affected section of piping.	IN 91-18
May 1990	Loviisa 1 (foreign)	A flow-measuring orifice flange in the main feedwater system ruptured after one of five main feedwater pumps tripped, causing a check valve in the line to slam shut, creating a pressure spike. Subsequent inspections determined that 9 of 10 flanges had thinned to below minimum wall requirements.	IN 91-18
July 1990	San Onofre 2	The licensee was forced to shut down the unit after discovering a steam leak in one of the feedwater regulating valve bypass lines.	IN 91-18
December 1990	Millstone 3	Two 6-inch pipes in the moisture separator drain (MSD) system ruptured when a MSD pump was stopped to facilitate component isolation for repairs. Stopping the pump caused a pressure transient. The high-energy water flashed to steam and actuated portions of the turbine building fire protection deluge system. Two 480-volt motor control centers and one non-vital 120-volt inverter were rendered inoperable by the flooding, resulting in the loss of the plant process computer and the isolation of the instrument air to the containment building.	IN 91-18
November 1991	Millstone 2	Rupture at an 8-inch elbow of a moisture separator reheater. High-energy water flashed to steam, actuating portions of the turbine fire protection deluge system. The license had not selected the ruptured elbow for ultrasonic testing in its erosion/corrosion monitoring program. See LER 50-336/91-12.	IN 91-18
1992	Millstone 3	See LER 50-309/92-07.	IN 93-21

Date	Site	Details	Ref.
1992	Maine Yankee	See LER 92-007.	IN 93-21
1992	Salem 1	Improper determination of code minimum wall thickness acceptance criteria resulted in improper disposition of degraded components. See Inspection Report 50-272/92-08.	IN 93-21
1992	Hope Creek	Lack of baseline thickness measurements (history) of originally designed piping was identified. See Inspection Report 50-354/92-11.	IN 93-21
1992	Millstone 1	Lack of baseline thickness measurements of replacement piping before the replacement piping was put into service. See Inspection Report 50-245/92-80.	IN 93-21
1992	Hope Creek	Use of engineering personnel who are unfamiliar with plant operating conditions, plant as-built designs, or erosion/corrosion history.	
1993	Diablo Canyon 1	Erosion/corrosion wear was discovered behind a thermal sleeve in the interior of the feedwater nozzle and on the feedwater nozzle itself.	IN 93-21
November 1994	Sequoyah 1	Licensee identified a 180-degree circumferential crack in a reduced section of 14-inch condensate piping used for flow-metering. The section of piping had been modeled incorrectly in CHECMATE™ without any diameter or thickness changes and had not been visually inspected.	IN 95-11
April 1997	Fort Calhoun	Manual scram and emergency boration following a 6-square-foot rupture of a 12-inch diameter sweep elbow in the fourth-stage extraction steam piping. A non-safety-related electrical load center, several cable trays and pipe hangers were damaged. In addition, asbestos-containing insulation was blown throughout the turbine building and portions of the fire protection system were actuated.	IN 97-84
May 1999	Point Beach 1	Manual trip from 100-percent power and manual safety injection actuation when the shell side of the feedwater heater ruptured. The fish-mouth rupture was approximately 27-inches long and 0.75-inch at its widest point. Feedwater heater leaks were also identified at Pilgrim Station and the Susquehanna units. None of the feedwater heaters had been included in a periodic inspection program.	IN 99-19
August 1999	Callaway	Operators manually tripped the reactor on indication of a steam leak in the turbine building. An 8-inch line from the first stage reheater drain tank to the high-pressure heater experienced a double-ended guillotine break.	Event Notification 36015
April 2001	Callaway	Significant wall thinning of MFW system pipe wall thinning to below the minimum thickness required by Code	

SKI Report 96:20

Piping Failures in United States Nuclear Power Plants: 1961-1995

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Summary

The Swedish Nuclear Power Inspectorate (SKI) is continuing to improve their process for the inspection of potential piping failures at Swedish nuclear power plants. As part of this effort SKI requested that the Chockie Group International, Inc. and Review & Synthesis Associates assist in the development of a data base of piping failures at US nuclear power plants. This report describes the data base that was produced and presents the information in a variety of formats to assist in understanding where and when the major piping failures have taken place.

Over 1500 reported piping failures were identified and summarized based on an extensive review of tens of thousands of event reports that have been submitted to the US regulatory agencies over the last 35 years. The process of locating and assessing these event reports was made difficult due to the fact that the reports are distributed among a number of data systems and document storage centers. The data base contains only piping failures; failures in vessels, pumps, valves, and steam generators or any cracks that were not through-wall are not included. The data base contains publicly available data for events from December 1961 through October 1995.

In the process of reviewing the 1511 reported piping failures it was observed that there has been a marked decrease in the number of failures after 1983 for almost all sizes of pipes. This is likely due to changes in the reporting requirements at that time and the corrective actions taken by utilities to minimize fatigue failures of small lines and IGSCC in BWRs.

One failure mechanism that continues to occur is erosion-corrosion. This mechanism accounts for most of the ruptures reported and probably is responsible for the absence of downward trends in ruptures.

A breakdown of the piping failures by failure mechanism, reactor type (BWR or PWR), and year of occurrence shows that fatigue-vibration is also a significant contributor to piping failures. However, most of such events occur in lines approximately one inch or less in diameter. While fatigue-vibration is a major factor in the smaller pipes, erosion-corrosion is a significant factor for both large and small lines. Together, fatigue-vibration and erosion-corrosion account for over 43 per cent of the 1511 reported piping failures.

An examination of the data by pipe size and failure type clearly shows that the overwhelming majority of failures have been leaks and that over half of the failures occurred in pipes with a diameter of one inch or less.

Included in the report is a listing of the number of welds in various systems in LWRs. These piping failure data should provide a valuable resource in understanding the nature of piping issues and in the improvement of inspections for potential piping problems.

- **System Name:** This field consists of a description of the plant system in which the pipe is located.

  Almost all nuclear power plant piping systems are covered in this data base. This includes Classes 1, 2, and 3, balance-of-plant (BOP), and protective systems such as fire, seal coolant, and emergency diesel cooling. Not included in the data base are those systems carrying air, oil or hydraulic fluid..

- **Pipe Size (inches):** This field contains the diameter of the pipe in inches as given in the piping failure reference material.

- **Small(<1) or Large (>1):** When the actual pipe size is not provided by the source, the description of the pipe or the system in which the pipe is located was examined to determine if the pipe is small or large in size. For example, if the pipe is described as a tube within a heat exchanger, then the pipe size is assumed to be "small". If the pipe is located in the service-water balance-of-plant system, then the pipe size is assumed to be "large". In such cases where such a determination could be made, a small pipe is assigned the value "<1" to indicate a size considerably less than one inch and a large pipe is assigned the value ">1" to indicate a size considerably greater than one inch. This field is also used to indicate pipe reducers. An example is a 2 inch by 1 inch reducer which is represented by the value of "2x1".

- **Failure Type:** This field contains the type of piping failure. Information for this field was determined by project staff by examining the full text descriptions of each of the piping failures and assigning the failure event to one of six different categories of piping failures. The six categories are: Breakage, Crack/Leak, Failed, Leak, Rupture, and Severed.

  In this report piping failures are defined as any condition from a small reported leak in any size line to the double-ended guillotine break (DEGB) of a large pipe. A predecessor to many piping failures is thinning of the pipe wall. Wall thinning involves substantial localized loss of pipe wall due to failure mechanisms such as erosion-corrosion, microbiologically-induced corrosion or other such corrosion mechanisms. Wall thinning can be detected by volumetric examination before any leakage occurs. Such incipient leakage events are not included in the Piping Failure Data Base.

  The following provides more detail on the failure type categories:

  - *Crack/Leak:* Flaws caused by such factors as construction errors, stress corrosion, and fatigue. These are flaws that have finite depths and penetrate the pipe wall creating a leak. In the data base *Crack/Leak* is considered a subset of the *Leak* category.

Table 5: *Number of Piping Failures for Each Failure Mechanism Category*

Failure Mechanism (Code)	Number of Failures
Corrosion/Fatigue (C/F)	14
Construction Defects/Errors (CD)	184
Design-Dynamic Load (DDL)	8
Water Hammer (WH)	35
Fatigue-Vibration (FV)	364
Erosion/Corrosion (E/C)	295
Stress Corrosion / IGSCC (SC)	166
Corrosion (COR)	72
Thermal Fatigue (TF)	38
Other (OTH)	43
Unknown Causes (UNK)	292
Total	1511

A breakdown of the piping failures by failure mechanism, reactor type (BWR or PWR), and year of occurrence (see Appendix C) shows that fatigue-vibration is also a significant contributor. However, most of such events occur in lines approximately one inch or less in diameter. While fatigue-vibration is a major factor in the smaller pipes (lines about 1 inch in diameter), erosion-corrosion is a significant factor for both large and small lines. Together, fatigue-vibration and erosion-corrosion account for over forty-three per cent of the 1511 reported piping failures.

Shown in Appendix C are tables that present the annual number of failures by failure mechanism, reactor type, and pipe size. What is not apparent in these tables is where erosion/corrosion occurs. Basically, single-phase erosion/corrosion can occur in the feedwater system for both BOP and Class 2. Two-phase erosion/corrosion is a wet steam phenomenon occurring downstream of the high pressure turbine and upstream of the turbine preheaters. The tables also do not indicate the severity of failure. However, this can be ascertained by reviewing the "System Name" field values in the data base's Piping Failures table (see Appendix E for a sample listing of the piping failure records). Also, it should be possible to separate the large erosion/corrosion failures from the small ones as well as separate single-phase from two-phase erosion/corrosion.

The only way to really interpret the graphs and tables for leaks, failures and ruptures is to cull each class of failures from the total failure population then subdivide them into BWRs and PWRs and further divide them by failure mechanism and system. The MS Access® software permits such culling of the data base so one can identify the cause of ruptures, for example, and determine the piping systems sensitive to such ruptures and the safety significance of the ruptures. Ruptures in the balance-of-plant have much less significance than in unisolable sections. Fortunately the only ruptures in unisolable piping have occurred in lines one-inch or less in diameter.

Table E-1: *Piping Failures in US Nuclear Power Plants from 1961 to 1995*

(Example List)

Plant Name	Event Date	System	Pipe Size (inches)	<1 or >1	Failure Type	Reference	Comments
Trojan	1/11/82	Main steam	6		Failed	AEOD/E4 16	Erosion/corrosion
Ginna	1/13/82	Containment heat removal	6		Leak	82-002	Stress corrosion
Quad Cities 2	1/15/82	Reactor water cleanup		>1	Leak	82-001	Stress corrosion
Cook 1	1/15/82	Instrument air		<1	Leak	82-005	Broken threaded nipple, unknown cause
Quad Cities 2	1/18/82	Reactor water cleanup	6		Leak	PNO III 82-009	Erosion/corrosion
Hatch 1	1/19/82	Coolant recirculation	0.5		Leak	82-006	3 pinhole leaks next to a weld. Sensing line replaced, unknown cause
Beaver Valley 1	1/19/82	Coolant recirculation		<1	Crack/ Leak	82-002	Frozen pipe
Cook 2	1/19/82	Containment heat removal	6		Leak	82-003	Fatigue-vibrational
Cook 1	1/23/82	Component cooling	1		Failed	82-006	Valve failed to close, unknown cause
Vermont Yankee	1/25/82	Main steam	6		Leak	82-001	Erosion/corrosion
Three Mile Island 1	1/28/82	Feedwater	2		Leak	82-002	Stress corrosion
Big Rock Point	1/28/82	Coolant recirculation		<1	Leak	82-003	Corrosion
Cook 2	1/28/82	Service water		>1	Leak	82-011	Erosion/corrosion, cavitation from throttling of butterfly valve
Cook 1	1/28/82	Service water		>1	Leak	82-009	Water hammer, line failure, cavitation
Oconee 2	1/28/82	Main steam	24		Rupture	PNO-II-82-72A, AEOD/E4 16	Erosion/corrosion
Crystal River 3	1/29/82	Reactor coolant	2.5		Leak	82-004, PNO II-82-013	cracked weld, Construction defects/errors
Crystal River 3	2/1/82	Reactor coolant	2.5		Leak	IN 82-09	Thermal fatigue
McGuire 1	2/12/82	High pressure core injection	1		Severed	82-017	Instrument line to HPCI, unknown cause

Seismic II/I

- The issue being appealed is whether SNC must consider hypothetical failures as part of scoping, as applied to a set of nonsafety-related piping that passes over safety related systems, structures or components.

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Seismic II/I

BACKGROUND

- During scoping evaluations, using the methodology described in Section 2.1 of the Hatch LRA based on the eight criteria found in the Rule, SNC found that some piping systems performed no intended function.
- Many, if not all, of these piping systems in the reactor building had piping supports with analyses upgraded to Seismic Category I.
- These piping supports analyses had been upgraded in order to assure adequate piping support during seismic events.

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Seismic II/I

BACKGROUND (Continued)

- **SNC brought these piping supports in scope since they performed an intended function - they prevent piping from falling on safety related equipment even in a seismic event.**
- **Apart from the hypothetical event of these piping segments falling on safety related SSCs, all other aspects related to failure of these nonsafety-related pipes have been addressed by bringing mitigating features (structures and components) in scope for:**
  - pipe whip
  - jet impingement
  - spray and drip
  - flooding

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Seismic II/I

BACKGROUND (Continued)

- **This approach results in aging management programs being applied to all mitigating features credited by SNC to assure there is no loss of intended function due to failures of nonsafety-related piping (within the context of the Hatch CLB and observed at Plant Hatch).**

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EVALUATION

- **What is the basis for the assertion that since the nonsafety-related pipe is seismically supported it can't fall?**
  - The Hatch design and licensing process, as conveyed in correspondence with NRC, reveals that the seismic margins analysis process employed by Hatch (IPEEE), and endorsed by NRC (EPRI NP-6041-SL, October 1988) states:

    *"**Welded non-seismic piping should not be considered to sever and fall provided that the anchor points such as wall penetrations, pumps and tanks, do not fail.** Past [structural integrity] design practices in the nuclear industry have been to assume that non-seismic piping will sever and "rain " down. Intermediate pipe supports may fail but ductile steel (not iron) pipes should not be considered to fall unless multiple support failures are possible in very long runs of pipe in open areas such as can be found in turbine bays."*

EVALUATION (Continued)

- **NRC staff has cited the SOCs (beginning with the last paragraph of 60 FR 22467 and concluding on page 22468) as evidence that nonsafety-related piping that is seismically supported must be brought in scope.**

EVALUATION (Continued)

- However, this entire discussion is within the context of the Commission's statements regarding consideration of hypothetical failures, shown in the previous paragraphs on page 60 FR 22467.

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Seismic II/I

EVALUATION (Continued)

- SNC has shown that falling of pipes is not assumed in the Hatch CLB.

AND

- NO experience data exists of welded steel pipe segments falling due to a strong motion earthquake.
- Falling of a piping system is extremely rare and only occurs when there is a failure or unzipping of the supports.
- These observations hold for new and aged pipe.

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EVALUATION (Continued)

- Thus, falling of these pipes should be considered hypothetical for Plant Hatch as contemplated by the Commission based on the SOC language.
- SNC has met the Rule requirement to bring in scope those SSCs that could prevent an intended function.

CONCLUSIONS

- By design, some nonsafety-related piping was supported using pipe supports that were analyzed to Seismic Category I criteria. In theory, if those supports were to fail, a loss of intended function might occur. Thus, SNC brought those supports in scope even though, in reality, much of the piping so supported was installed using a conservative "cookbook" approach even when it did not need to be seismically supported.

Seismic II/I

CONCLUSIONS

- To postulate these pipes falling is beyond the CLB - it is hypothetical within the context of the SOCs for the Rule - and does not need to be considered in scoping.
- The Plant Hatch design has already considered the non-hypothetical failure modes of the nonsafety-related piping and taken appropriate scoping action so that there would be no loss of intended function.

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Discussion

SOUTHERN COMPANY

Hatch License Renewal
Class 1 Small Bore Piping (Excluding Socket welds)

ASME Code inspections do not require volumetric examination of small bore piping (<4 inches in diameter); therefore dependent upon leak-before-break for crack detection

Small bore piping could not meet the leak-before-break criteria in NUREG 1061, Vol. 3

BWRVIP-75 provides a program for inspection of large bore stainless steel piping (including Nuclear grade) that is susceptible to IGSCC. - The SER for BWRVIP-75 establishes criteria for determining the most susceptible locations for IGSCC

MRP has provide in a letter dated March 16, 2001 Interim: Thermal Fatigue Guidelines for identifying piping lines that are not susceptible to cracking - Evaluation not complete

NUREGs -0531 and -0679 document cracking associated with small bore piping in late 70s

- Cracks associated with fatigue and IGSCC aging mechanisms

- IGSCC of small diameter pipe preceded the IGSCC of large diameter pipe

- BWRs have instituted corrective actions to reduce the susceptibility of the piping to these aging mechanisms

Hatch - Applicant does not credit hydrogen water chemistry to mitigate IGSCC

- Applicants evaluation indicates Class 1 small bore piping lines are not susceptible to thermal stratification

- Applicant indicates breaks in small bore piping in RWCU and RCIC lines could result in the loss of coolant that would exceed the capacity of the make-up system

STAFF POSITION:
Volumetric examination of small bore piping is necessary if thermal fatigue resulting from thermal stratification or turbulent penetration is a plausible aging effect or if the pipe locations inspected as part of the BWRVIP -75 program are less susceptible to IGSCC than the small bore stainless steel piping or hydrogen water chemistry (HWC) per BWRVIP-75 are not utilized. IGSCC susceptibility may be determined using the criteria discussed in the staff SER for BWRVIP-75. Applicant to review MRP Interim Thermal Fatigue Guidelines and to provide guidelines applicable to Hatch.

If volumetric examination to detect IGSCC is determined to be necessary (large bore inspection locations are less susceptible to IGSCC than small bore piping or HWC is not utilized), than the number and frequency of small bore pipe welds that are required to be inspected during the license renewal period shall be the number and frequency for the welds approved in the staff's SER for BWRVIP -75.

If volumetric examination to detect thermal fatigue is determined to be necessary, than the number and frequency of small bore pipe welds that are required to be inspected during the license renewal period shall be submitted for staff review and approval.

Kamal —
Mark —

NEI
NUCLEAR ENERGY INSTITUTE

Alexander Marion
DIRECTOR
ENGINEERING DEPARTMENT
NUCLEAR GENERATION DIVISION

March 16, 2001

Received from K Manly
May 30, 2001

Mr. Jack R. Strosnider, Jr.
Director, Division of Engineering
Office of Nuclear Reactor Regulation
Mail Stop O9-E3
U. S. Nuclear Regulatory Commission
Washington, DC 20555-0001

SUBJECT: Interim Thermal Fatigue Guideline

PROJECT NUMBER: 689

Dear Mr. Strosnider:

The EPRI Materials Reliability Program (MRP), *Interim Thermal Fatigue Guideline (MRP-24)* is enclosed for your information. This document was recently provided to the industry for assessing thermal fatigue of reactor coolant piping systems.

During the past few years, several domestic and foreign plants experienced thermal fatigue cracking in stagnate-flow piping attached to PWR main reactor coolant systems. In 1998, NEI, the MRP and the NRC discussed a concern that the ASME Code required surface examination would not detect thermal fatigue in small diameter high-pressure safety injection piping (Class 1 piping). The MRP evaluated this concern and formed the Thermal Fatigue Issue Task Group (ITG) to develop a guidance document to assess thermal fatigue in Class 1 piping systems.

In late 1999, the ITG decided to develop an interim guideline since the final guideline would not be available until mid-2002. The interim guidance provides evaluation and inspection recommendations for determining if a potential exists for thermal fatigue in systems with normally stagnate-flow. The scope of the interim guidance is limited to locations that have previously experienced thermal fatigue in domestic or similar foreign plants, but are not currently part of another augmented inspection program. The guidance also provides screening criteria to identify piping lines that are not susceptible to cracking.
The ITG discussed the proposed interim guidance with the NRC staff in late-2000. The enclosed guide was published after considering the NRC staff comments.

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Ta... 6

FROM : VERMONT YANKEE RI ISI REPORT

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FMECA - Segment Risk Ranking Report

Segment ID	Number of Welds	Lines in Segment	Welds in Segment	Degradation Mechanisms	Degradation Mechanism Category	Consequence ID(s)	Consequence Category	Risk Category	Risk Rank
MSD-001	3	1.5-MSD-420	MSD420-F9, MSD420-F8, MSD420-F7	TASCS	SMALL LEAK	55	LOW	CAT6	LOW
MSD-002	3	1.5-MSD-421	MSD421-F7, MSD421-F8, MSD421-F9	TASCS	SMALL LEAK	55	LOW	CAT6	LOW
MSD-003	4	1.5-MSD-422	MSD422-F4, MSD422-F3, MSD422-F2, MSD422-F1	TASCS	SMALL LEAK	55	LOW	CAT6	LOW
MSD-004	8	2-MSD-2A	MSD2A-F1, MSD2A-F2, MSD2A-F3, MSD2A-F4, MSD2A-F5, MSD2A-F6, MSD2A-F7, MSD2A-F8	TASCS	SMALL LEAK	55	LOW	CAT6	LOW
MSD-005	14	2-MSD-2B	MSD2B-F1, MSD2B-F2, MSD2B-F3, MSD2B-F4, MSD2B-F5, MSD2B-F6, MSD2B-F7, MSD2B-F7A, MSD2B-F7B, MSD2B-F7C, MSD2B-F7D, MSD2B-F7E, MSD2B-F7F, MSD2B-F8	TASCS	SMALL LEAK	55	LOW	CAT6	LOW
MSD-006	14	2-MSD-2C	MSD2C-F1, MSD2C-F2, MSD2C-F3, MSD2C-F4, MSD2C-F5, MSD2C-F6, MSD2C-F7, MSD2C-F7A, MSD2C-F7B, MSD2C-F7C, MSD2C-F7D, MSD2C-F7E, MSD2C-F7F, MSD2C-F8	TASCS	SMALL LEAK	55	LOW	CAT6	LOW
MSD-007	8	2-MSD-2D	MSD2D-F1, MSD2D-F2, MSD2D-F3, MSD2D-F4, MSD2D-F5, MSD2D-F6, MSD2D-F7, MSD2D-F8	TASCS	SMALL LEAK	55	LOW	CAT6	LOW
MSD-008	1	3-MSD-2	MSD2-F1	TASCS	SMALL LEAK	56	MEDIUM	CAT5	MEDIUM

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FMECA - Segment Risk Ranking Report

Segment ID	Number of Welds	Lines in Segment	Welds in Segment	Degradation Mechanisms	Degradation Mechanism Category	Consequence ID(s)	Consequence Category	Risk Category	Risk Rank
MSD-009	2	3-MSD-2	MSD2-F2, MSD2-F3	TASCS	SMALL LEAK	57	LOW	CAT6	LOW
MSD-010	5	3-MSD-2	MSD2-F4, MSD2-S1, MSD2-S2, MSD2-S4, MSD2-S3	TASCS	SMALL LEAK	58, 56	MEDIUM	CAT5	MEDIUM

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

September 15, 2000

Carl Terry, BWRVIP Chairman
Niagara Mohawk Power Company
Post Office Box 63
Lycoming, NY 13093

SUBJECT: SAFETY EVALUATION OF THE "BWRVIP VESSEL AND INTERNALS PROJECT, BWR VESSEL AND INTERNALS PROJECT, TECHNICAL BASIS FOR REVISIONS TO GENERIC LETTER 88-01 INSPECTION SCHEDULES (BWRVIP-75)," EPRI REPORT TR-113932, OCTOBER 1999 (TAC NO. MA5012)

Dear Mr. Terry:

The NRC staff has completed its review of the Electric Power Research Institute (EPRI) proprietary report TR-113932, "BWR Vessel and Internals Project, Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedules (BWRVIP-75)," dated October 1999, submitted to the U. S. Nuclear Regulatory Commission (NRC) for staff review by letter dated October 27, 1999. The non-proprietary version of the BWRVIP-75 report was submitted by letter dated February 29, 2000.

The BWRVIP-75 report proposes revisions to the extent and frequencies for piping inspection contained in Generic Letter (GL) 88-01. The proposed revisions are based on the consideration of inspection results and service experience gained by the industry since the issuance of GL 88-01, and includes additional knowledge regarding the benefits of improved BWR water chemistry. The BWRVIP-75 report also provides justification for the proposed inspection criteria for Category A through E welds for the respective conditions of normal water chemistry (NWC) and hydrogen water chemistry (HWC).

The staff met with senior management representatives of the BWRVIP and the BWR Owner's Group (BWROG) on September 13, 2000, to discuss issues of concern, including the staff's review of the BWRVIP-75 report. During this meeting, the BWRVIP stated that the BWRVIP-75 report is a deterministic evaluation, and the proposed methodology does not rely on risk insights to justify the proposed reduction in inspection scope or frequency. This is not clear from the report, especially Section 4.0, "Risk Consideration." The staff requests that the report be modified to clearly state that the methodology used is deterministically based.

Laboratory tests have shown that the materials with such catalytic coatings exhibit very low crack growth rates (CGRs) as its ECP is lowered to below -400 mV with feedwater hydrogen concentration less than 0.2 ppm.

(B) For an effective NMCA program, the following acceptance criteria should be met:

(1) The hydrogen vs. oxygen molar ratio should be measured to determine the effectiveness of the NMCA condition. The acceptable hydrogen vs. oxygen molar ratio is 4 and above. A more detailed discussion of the hydrogen vs. oxygen molar ratio will be provided in the staff's SE for the BWRVIP-62 report.

(2) The acceptable NWCA program should have a monitoring program to determine if the NMCA remains applied and to determine when the process needs to be re-applied.

(3) NMCA is only applicable when HWC is available, and shall be available at greater than 90 percent of the hot operating time. Tests at Duane Arnold have shown that the ECP responds very quickly to hydrogen injection or stoppages with NMCA, and that the "memory" effect associated with conventional HWC (to be discussed in the staff's SE for the BWRVIP-62 report) appears to be absent for NMCA. If the NMCA availability requirement is not met, the inspection frequency should be increased to that of the HWC or NWC condition, as appropriate.

(4) Conductivity transients (> 0.3 uS/cm) may occur during plant operation. Short transients may not have any significant effect on IGSCC. Therefore, when the duration of the conductivity transients under NMCA condition is 24 hours or less, the time associated with the transients need not be subtracted from the acceptable NMCA service time.

Open Item 3.9 Identification of Safety Significant Locations

The staff met with senior management representatives of the BWRVIP and the BWR Owner's Group (BWROG) on September 13, 2000, to discuss issues of concern, including the staff's review of the BWRVIP-75 report. During this meeting, the BWRVIP stated that the BWRVIP-75 report is a deterministic evaluation, and the proposed methodology does not rely on risk insights to justify the proposed reduction in inspection scope or frequency. This is not clear from the report, especially Section 4.0, "Risk Consideration." The staff requests that the report be modified to clearly state that the methodology used is deterministically based. The staff concurs with the BWRVIP-75 report that the use of risk insights by licensees will improve the final distribution of weldments to be inspected by systematically incorporating plant-specific characteristics in the selection process.

The safety significance of the locations to be inspected should be determined using a ranking process, similar to that discussed in Section 4 of the BWRVIP-75 report, by a panel knowledgeable of the IGSCC mechanism and its impact on the subject piping systems to identify the locations of greatest safety significance with respect to changes in the IGSCC inspection program. The staff recommends that inspection locations should be distributed among the weldments in each category until the required percentage of locations have been selected, with the highest safety-significant locations being selected first. During the selection of inspection locations, licensees should give additional consideration to those locations having attributes that would promote IGSCC, or where IGSCC could be accelerated by crevice

corrosion or thermal fatigue. The attributes to be considered are: high carbon or low ferrite content, crevice or stagnant flow condition, evidence of weld repair, surface cold work, and high fit-up, residual and operating stresses. These locations should have higher inspection priority.

4.0 RECOMMENDATIONS AND CONCLUSIONS

The staff has reviewed the BWRVIP-75 report and finds that the guidance provided in the subject report for revisions of Generic Letter 88-01 inspection schedules is generally acceptable for the inspection of the subject piping welds in BWRs, except for the above enumerated open items. Once the staff's recommendations, as described above and summarized in the table below, are incorporated into the proposed guidance, the staff finds that the revised BWRVIP-75 report can be used to replace the inspection guidance in GL 88-01. Further, the staff finds that, with the exception of the open items discussed in this SE, the BWRVIP-75 guidance is acceptable for licensee referencing as the technical basis for relief from, or as an alternative to, the ASME Code and 10 CFR 50.55a, in order to use the sample schedules and frequencies specified in the BWRVIP-75 report that are less than those required by the ASME Code. The staff's approval of the as-revised BWRVIP-75 report also allows licensees to utilize the as-revised BWRVIP-75 guidance in lieu of licensees' commitments to GL 88-01 and NUREG-0313, Rev. 2, or as the technical basis for a plant-specific request for a license amendment to change technical specifications requiring GL 88-01 or NUREG-0313, Rev. 2 inspections.

The staff concludes that the licensee's implementation of the guidelines in the BWRVIP-75 report, with modifications to address the staff's conclusions and recommendations above, will provide reasonable assurance for the structural integrity of the affected BWR piping as addressed in the BWRVIP-75 report.

The staff requests that BWRVIP review and resolve the open items raised above, and incorporate the staff's conclusions and recommendations into a revised BWRVIP-75 report. The staff requests that the BWRVIP provide the proposed revised inspection guidance to the staff in a timely manner.

Small-Bore Piping

- **Item to be appealed is the staff position that small-bore butt-welded piping receive a one-time examination**

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Small-Bore Piping

- **Issue initially identified as RAI 3.2.3.2-8**
  - Referenced NRC Bulletin 88-08 for PWRs
  - Asked SNC to identify any ASME Class 1 piping below 4" that could be subject to:
    - » Thermal Fatigue
    - » Vibratory Fatigue
    - » Stress Corrosion Cracking
  - For each System SNC was to:
    - » Provide basis for concluding systems were subject to these aging effects
    - » Identify Aging Management Programs that can be used to determine if cracking had occurred
- **SNC provided the applicable systems and the applicable means of aging management in the RAI response**

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Small-Bore Piping

- **Issue identified as open item 3.2.3.2.3-1 in the initial SE**
  - The staff concern identified is focused on cracking due to unanticipated high cycle thermal fatigue resulting from:
    - » thermal stratification
    - » turbulent penetration
  - The staff concern expressed in the open item excluded socket welded piping and fittings
  - The staff noted the Code inspection and Fatigue monitoring programs did not address this type cracking
  - The staff recommended supplemental volumetric examination on limiting locations subject to cracking caused by these mechanisms

SOUTHERN COMPANY

Small-Bore Piping

- **SNC evaluated the Class 1 piping systems based on SE criteria**
  - All Class 1 piping less than 4" identified
  - Socket Welded piping and fittings were screened out, eliminating almost all piping and fittings 2" and under
  - The remaining population was evaluated for the potential to experience thermal stratification and turbulent penetration using the MRP Interim Thermal Fatigue Criteria (MRP-24)
  - Make-up capacity was used to evaluate significance of a postulated break (IWB-1220(a) of ASME Section XI, 10CFR50.55a(c)(2)(i))
    - » **HNP-1** 2.5" for water, 5.0" for steam
    - » **HNP-2** 2.1" for water, 4.2" for steam

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Small-Bore Piping

- **The locations evaluated are:**
  - 4"x2" reducer on the RPV head vent
    - » downstream piping is socket welded
    - » vent line exposed only to steam during operation, no cycling or turbulent penetration occurs
    - » 2" is below the make-up capacity line size for steam (5.0/4.2")
    - » 4" side is in scope for ISI
    - » 2" side is in scope for Class 1 leakage test each outage
    - » Location not subject to aging mechanism of concern
    - » Failure does not result in significant safety issue (make-up)
    - » Augmented Examination not warranted

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Small-Bore Piping

- ECP sensor lines with 4" pipe
  - » Exceeds the size of concern, but considered to be technically correct
  - » Influent and effluent lines are 2" (below make-up capacity)
  - » Line experiences constant flow so no thermal stratification or turbulent penetration
  - » Only stainless pipe in population (< 4"), potential for IGSCC exists but is low since material is low-carbon stainless
  - » Line receives regular examination associated with change out of ECP sensors
  - » Line is in scope for Class 1 leakage test each outage
  - » Location not subject to aging mechanism of concern
  - » Failure does not result in significant safety issue (make-up)
  - » Augmented Examination not warranted

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Small-Bore Piping

- RWCU return to RCIC, 3 welds downstream of 1G31-F039 valve
  - » Piping is 3" and exceeds the makeup criteria exemption (2.5")
  - » Piping experiences steady flow during operation, no stratification
  - » Pressure is provided from the RWCU to RCIC line, no turbulent penetration
  - » Line is in scope for Class 1 leakage test each outage
  - » Location not subject to aging mechanism of concern
  - » Augmented Examination not warranted
- RWCU return to HPCI, 3 welds downstream of 1G31-F203 valve
  - » Piping is 3" and exceeds the makeup criteria exemption (2.5")
  - » Piping experiences steady flow during operation, no stratification
  - » Pressure is provided from the RWCU to HPCI line, no turbulent penetration
  - » Line is in scope for Class 1 leakage test each outage
  - » Location not subject to aging mechanism of concern
  - » Augmented Examination not warranted

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Small-Bore Piping

- Main Steam to RCIC branch connection
  - » Turbulence is probable, but line contains steam only so thermal cycling due to turbulent penetration not likely (MRP-24)
  - » Thermal stratification unlikely due to the steam only environment
  - » Line is below make-up criteria for steam (5.0")
  - » Location not subject to aging mechanism of concern
  - » Failure does not result in significant safety issue (make-up)
  - » Line is in scope for Class 1 leakage test each outage
  - » Augmented Examination not warranted

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Small-Bore Piping

- Main Steam Isolation Valve Leak-off and HPCI/RCIC steam line drains
  - » The 3" portion of theses lines are well downstream of source
  - » The influent lines to the 3" section passes through 1", 1.5" and 2" lines before reaching the 3" segment
  - » Turbulent penetration is not a concern
  - » Thermal stratification may occur, but no cycling is likely
  - » Line size is below make-up capacity limit for steam (4.2"/5.0")
  - » Line is in scope for Class 1 leakage test each outage
  - » Failure does not result in significant safety issue (make-up)
  - » Location not subject to aging mechanism of concern
  - » Augmented Examination not warranted

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Small-Bore Piping

- **Conclusion**

SNC has evaluated the small-bore piping as specified by NRC. The result of that evaluation is that there are no locations subject to the degradation mechanism identified by NRC. Therefore, a one-time inspection is not warranted and this item should be closed.

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ENVIRONMENTAL FATIGUE

Staff requested applicant address six NUREG/CR-6260 locations

- Hatch is only license renewal applicant that has not provided plant specific evaluation of these locations

Hatch Position

- Cited two generic EPRI studies as demonstrating sufficient conservatism in the design transients to account for environmental effects
- No specific evaluation of the 6 locations for the Hatch Plant are necessary

Staff Response

- Only one of the studies is applicable to a BWR 4 and it only addresses the FW nozzle
- The FW nozzle used the results of actual monitoring of the FW temperature at Susquehanna
- No comparison between the actual operating history at Hatch with that of Susquehanna was provided (in terms of rate of temperature change during plant transients)
- Susquehanna is a larger BWR/4 than Hatch (therefore they are not identical)
- It is not clear that the FW line configurations and operation are identical (RCIC and RWCU tee configuration and operation)

Hatch Approach to Address Environmental Fatigue

- **Item to be appealed is the staff position that the reactor water environmental factors for metal fatigue have not been adequately accounted for in using design basis transients to monitor fatigue at Plant Hatch**

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Hatch Approach to Address Environmental Fatigue

- **Background**
  - The issue of fatigue in nuclear power plants has been an issue of study and debate for several years. Examples include:
  - GSI-78 was issued in June 1983 to determine the whether transient monitoring was warranted
  - November 1990 - a NUMARC/Industry position on fatigue evaluation for license renewal was submitted to NRC
  - GSI-166 " Adequacy of Fatigue Life of Metal Components" was issued April 1993
  - NUREG/CR-5999 (interim fatigue design curves) were published in April 1993
  - NRC issued "Fatigue Action Plan" July 1993
  - Multiple industry studies and assessments were underway during the same time period

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Hatch Approach to Address Environmental Fatigue

- **Background cont'd**
  - NUREG/CR-6260 "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components" was issued March 1995
    - » Identified six or more fatigue-critical locations for seven reactor types
    - » Direct application of ANL fatigue curves produced CUFs greater than 1.0 for 40 and 60 years at many locations
    - » Reducing cycles from design basis to actual or making strain rate adjustments CUF was reduced to below 1.0 for 40 and 60 years for most locations
  - NRC performed a probabilistic study limited to 40 years
    - » Impact of fatigue failure in piping using NUREG/CR-5999 curves was negligible
    - » Crack initiation does not ensure through wall flaws
    - » Contribution to CDF insensitive to CUF

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Hatch Approach to Address Environmental Fatigue

- **Background cont'd**
  - The probabilistic risk study results were later incorporated into the Fatigue Action Plan which was completed and documented in SECY-95-245.
  - SECY-95-245, "Completion of Fatigue Action Plan" was issued September, 25, 1995 and documented that:
    - » the staff believes no immediate staff or licensee action is necessary to deal with issues in the fatigue action plan
    - » fatigue failure is not a significant contributor to core-melt frequency
    - » the staff does not believe it can justify requiring a backfit of the environmental fatigue to operating plants
    - » the staff believe that the Fatigue Action Plan issues should be evaluated for any proposed extended period of operation for license renewal
    - » GSI-166 closed for operating plants; GSI-190 remains open for license renewal

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Hatch Approach to Address Environmental Fatigue

- **Background cont'd**
  - NRC conducted a Fatigue Workshop November 17, 1999 where results of the latest probabilistic risk study on fatigue were presented
  - This study, NUREG/CR-6674, "Evaluation of Environmental Effects on Fatigue Life of Piping" was published June 2000
    - » Extended probabilistic risk study from 40 years to 60 years
    - » Included probabilistic calculations for 47 component locations that are the same as those used in NUREG/CR-6260
    - » Study used conservative assumptions
    - » Results were used as the basis for closing GSI-190
    - » Finding - Environmental fatigue is not a safety issue
    - » Finding - There is a potential for increased leakage

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Hatch Approach to Address Environmental Fatigue

- **Background cont'd**
  - Status today
    - » After almost 20 years of intensive study, analysis and testing, conducted by NRC, national laboratories and the nuclear industry we have continued to show and affirm that metal fatigue is not a safety significant issue and that the design of nuclear plants is conservative and robust assuring safe operation
    - » In spite of these results, NRC has mandated that fatigue be monitored during the license renewal period and that it be considered a TLAA in accordance with 10 CFR 54
    - » In response, the industry initially developed plant-specific programs to address fatigue. More recently, the Materials Reliability Project (MRP) has submitted draft guidance on how plants can monitor this non-safety issue and thus meet NRC's criteria
    - » The method proposed for use at Plant Hatch is the basis for one of the conservative approaches proposed by the MRP

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Hatch Approach to Address Environmental Fatigue

- **Monitor Class 1 locations with a 40-year design basis CUF > 0.1**
  - Four limiting RPV locations in each Hatch unit
  - Nine limiting Class 1 piping locations encompassing both Hatch units
  - Six NUREG/CR-6260 locations included in program
  - Use actual cycle counts and design basis transient severity
- **Design basis transient severity overwhelms environmental effects**
- **Based on 4-step application of EPRI/NEI generic studies**
  - Step 1: Calvert Cliffs study (EPRI TR-107515, December 1997)
  - Step 2: BWR plant study (EPRI TR-110356, April 1998)
  - Step 3: Adjustment factor to account for revised F_{en} relationships
  - Step 4: Additional parametric studies and plant comparisons

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Hatch Approach to Address Environmental Fatigue

- **Step 1: Calvert Cliffs Study -- Objectives**
  - Undertaken by EPRI to develop EPRI/NEI/industry position with respect to environmental fatigue for license renewal
  - Calvert Cliffs = lead plant
  - Intended to use the "latest rules" on environmental fatigue, etc.
    - » Apply the "new" EPRI/GE F_{en} approach (EPRI TR-105759, December 1995)
    - » Selective application of environmental rules (i.e., apply effects only when threshold criteria are satisfied)
  - Investigate the postulated effects of PWR environment on fatigue usage and project results for the 40 and 60 year license terms
  - Actual transients evaluated with environmental effects, projected to 60 years, and compared to design basis CUFs

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Hatch Approach to Address Environmental Fatigue

- **Step 1: Calvert Cliffs Study -- Results**
  - Design basis transient definitions concluded to be very conservative
    - » CUF ratios on the order of 20 to 100 (or higher), when compared to actual transient definitions
  - Average environmental (F_{en}) multipliers of 1.4 to 1.6
    - » Typical Results:

Unit	Location	Actual CUF for 60 Years	CUF with F_{en} for 60 Years	**Average F_{en}**
1	SG1_FW1	1.216	1.597	**1.31**
1	SG1_FW2	0.809	0.840	**1.04**
1	SG2_FW1	1.218	1.941	**1.59**
1	SG2_FW2	0.809	0.914	**1.13**
2	SG1_FW1	2.076	2.892	**1.39**
2	SG1_FW2	1.416	1.674	**1.18**
2	SG2_FW1	2.079	3.154	**1.52**
2	SG2_FW2	1.422	1.764	**1.24**

  - CONCLUSION: Design basis CUF is significantly higher than actual transient CUF with F_{en}

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Hatch Approach to Address Environmental Fatigue

- **Step 2: BWR Study**
  - OBJECTIVE: Ascertain whether similar conclusions to Calvert Cliffs study existed for a BWR
  - Design basis transient definitions concluded to be very conservative
    - » CUF ratios of 20 to 100 (compared to actual transient definitions)
  - Average environmental (F_{en}) multipliers of 1.0 to 2.7
    - » Typical Results:

Location	Actual CUF for 60 Years	CUF with F_{en} for 60 Years	**Average F_{en}**
CRD Penetration	0.01237	0.03392	2.74
FW Loop A Safe End	0.00882	0.00894	1.01
FW Loop A Nozzle Forging	0.00073	0.00073	1.00
FW Loop B Safe End	0.00918	0.00918	1.00
FW Loop B Nozzle Forging	0.00073	0.00073	1.00

  - CONCLUSION: Design basis CUF is significantly higher than actual transient CUF with F_{en} (same as Calvert Cliffs study)

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Hatch Approach to Address Environmental Fatigue

- **Step 3: Adjustment factor to account for revised F_{en} relationships**
  - Argonne National Laboratory generated revised F_{en} relationships based on additional data
    - » Supersedes EPRI/GE F_{en} relationship used in Calvert Cliffs and BWR studies
    - » NUREG/CR-5704 for stainless steel (April 1999)
    - » NUREG/CR-6583 for carbon/low alloy steel (March 1998)
  - Hatch response to RAI 4.2-2 evaluated differences
    - » Additional factor of 1.0 for carbon/low alloy steel
    - » Additional factor of 2.0 for stainless steel
  - Application of factors to Calvert Cliffs and BWR studies effectively brings results up to-date

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Hatch Approach to Address Environmental Fatigue

- **Step 4: Additional parametric studies**
  - Plant comparisons -- Hatch vs. BWR study plant (Generic BWR)
    - » Both BWR-4s (same systems, etc.)
    - » Design transients are nearly identical
      - Same types
      - Same "size and shape"
    - » Heat balance parameters very similar
      - Feedwater temperatures within 4%
      - Recirculation temperatures within 1%
      - RPV dome pressures within 3%
      - Recirculation flows are the same
      - Feedwater flow for Hatch is 15% lower (conservative)
  - Conclusion: Hatch = Generic BWR (design basis point-of-view)

Location	CUF with F_{en} for 60 Years	Correction Factor to Account for NUREG/CR-6583 or NUREG/CR-5704	Revised CUF with F_{en} for 60 Years	Design Basis CUF	Margin
CRD Penetration	0.034	2.0	0.068	0.875	12.9
FW Loop A Safe End	0.009	2.0	0.018	0.471	26.3
FW Loop A Nozzle Forging	0.001	1.0	0.001	< 0.1	> 100
FW Loop B Safe End	0.009	2.0	0.018	0.471	25.7
FW Loop B Nozzle Forging	0.001	1.0	0.001	< 0.1	> 100

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Hatch Approach to Address Environmental Fatigue

- **Step 4: Additional plant comparisons**
  - Plant comparisons -- Hatch vs. BWR study plant
    - » No plant data available for Hatch
    - » Limited transient data for other BWRs available
      - Doesn't address the Hatch issue
    - » Parametric studies were performed
      - Pressurizer surge line results from Calvert Cliffs study (see Figure 1)
      - Additional BWR results (see Figure 2)
      - Demonstrate plant operational variations are insensitive to design basis conservatisms
  - Conclusion: Compared to design basis severity, any operational differences between Hatch and Generic BWR are insignificant

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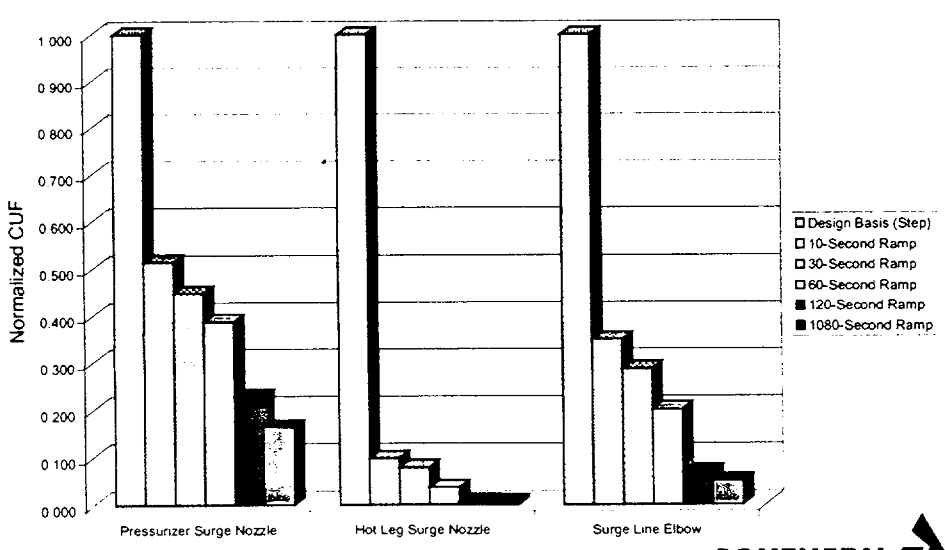
Hatch Approach to Address Environmental Fatigue

Figure 1: Sensitivity of Plant Operation Relative to Design Transients



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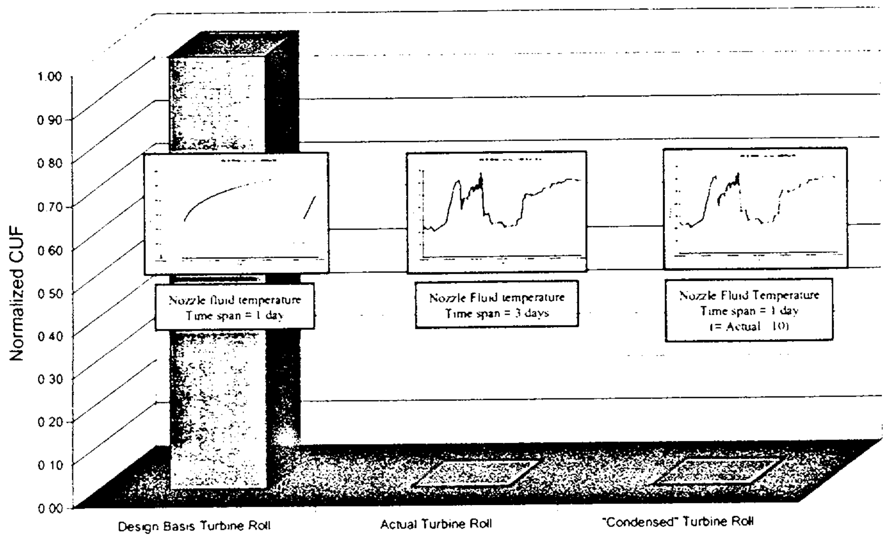
Hatch Approach to Address Environmental Fatigue

Figure 2: Sensitivity of Plant Operation Relative to Design Transients



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Hatch Approach to Address Environmental Fatigue

- **Conclusions**
  - Hatch approach tracks CUF for all bounding Class 1 locations
    - » 17 locations (two units) vs. 6 locations identified in NUREG/CR-6260
  - EPRI/NEI studies demonstrate that the conservatism of design basis transient definitions is much higher than factors associated with environmental fatigue
    - » Adjustments have been made to bring studies up to-date
    - » Plant-to-plant operational variations are insignificant compared to design basis conservatism (design = steps vs. actual = ramps)
      - Demonstrated for generic BWR-4 for Turbine Roll event for FW nozzle
        - Most critical location, most severe transient in BWR
        - Bounds other locations
        - For piping, NB-3200 vs. NB-3600 conservatism also exists

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Hatch Approach to Address Environmental Fatigue

- **Conclusions (cont'd)**
  - Hatch program tracks actual transient counts and uses design basis severity to estimate CUF
    - » Conservative compared to actual transient severity with F_{en}
  - Hatch program projects CUF results and takes corrective action if CUF exceeds allowable

Hatch approach provides effective aging management program, and adequately addresses environmental fatigue effects for license renewal.
Therefore, this open item should be closed.

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Discussion

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PIPE BREAK CRITERIA

54.3 Definition of TLAA

- Pipe break postulation based on CUF meets all six criteria
- Statement of considerations identifies pipe break as potential TLAA
- NRC Standard Review Plan Table 4.1-2 lists as potential TLAA

Previous renewal application reviews

- Issue raised in Calvert Cliffs review (SER pg 4-6)
- B&W Topical Report BAW 2243A lists pipe break postulation based on CUF as a TLAA

Hatch Interpretation

- Criteria was only applicable to initial screening for selecting a set of bounding break locations

Staff Response

- Pipe break criteria does not specify a minimum number of locations that are considered adequate
- Advanced reactor designs used the same CUF criteria for 60-years
- The criteria is not overly conservative because it does not consider environmental effects
- Statistical evaluations of fatigue test data by ANL published in NUREG/CR-6335 show the probability of fatigue cracking increases with increasing CUF

Pipe Break Criteria

- **Item to be appealed is the staff position that the pipe break criteria of MEB 3-1 (0.1 CUF) is a TLAA.**

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Pipe Break Criteria

- **Issue initially identified as potential TLAA in rule SOCs.**
- **SNC acknowledged this possibility and arranged a meeting with NRC to discuss possible approaches.**
- **SNC and NRC met June 24, 1999 to discuss options for addressing this issue.**
  - NRC noted that 0.1 CUF had been used as a screening criterion for use in postulating pipe break locations, not because it represented a fatigue level of concern, but to provide a consistent value that was conservative for postulating pipe break locations.
  - MEB 3-1 purpose is "...utilize the available piping design information by postulating pipe ruptures at locations having a relatively higher potential for failure, such that an adequate and practical level of protection may be achieved."

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Pipe Break Criteria

- **In RAI 4.2.1 NRC requested that SNC provide a description of a TLAA for the pipe break criteria at Plant Hatch and describe how the TLAA meets the requirements of 10 CFR 54.21.**
- **SNC's response noted:**
  - The Hatch CLB is in compliance with MEB 3-1.
  - After evaluation of MEB 3-1 criterion and the results of the 1999 meeting with NRC, SNC concluded that the criterion established a bounding set of locations for line break consideration.
  - Therefore the results of the analyses for 40 years did not need to be reestablished for 60 years.
  - Future Class 1 design changes with a postulated CUF of 0.1 or greater for the extended period would be evaluated in accordance with MEB 3-1.

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Pipe Break Criteria

- **In Open Item 4.1.3-1 (b) Staff reiterated their position and noted:**
  - Staff agreed with the SNC position that the pipe break criteria establish a bounding set of locations for line break consideration.
  - Staff still considers pipe break postulations a TLAA because the fatigue calculation is a TLAA.
  - NRC previously identified high-energy line break postulation based on fatigue cumulative usage factor as a TLAA in accordance with 10 CFR 54.3 (60 FR 22480, May 8, 1995).
  - Therefore the staff requested that SNC include pipe break postulations based on fatigue usage factor as a TLAA.

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Pipe Break Criteria

- **SNC's position is:**
  - The Hatch CLB is in compliance with MEB 3-1 will continue to use the criteria for future design changes.
  - Use of MEB 3-1 and the 0.1 CUF criterion identified bounding locations that were used to assess the need for pipe whip restraints and other protective devices, thus assuring that an "adequate and practical level of protection" was achieved. This being done, the intent of MEB 3-1 was satisfied.
  - Operation for an additional 20 years will not change these bounding locations.
  - Closure of GSI-190 indicates metal fatigue is not of safety significance.
  - It has been shown that transient severity used in developing design CUFs is conservative, thus the likelihood of failure due to fatigue is even less than conservatively assumed when MEB 3-1 was developed.

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Pipe Break Criteria

- **SNC's position (Continued)**
  - Contrary to the staff statement in the open item, 60 FR 22480, May 8, 1995, did not identify high-energy line break as a TLAA - rather it stated "... these analyses **could** include.....high-energy line-break postulation based on cumulative usage factor."
  - Later in that same reference addressing comments on TLAA definition the purpose of the TLAA consideration appears to be directed at steps necessary to "..provide reasonable assurance that there is no undue risk to the public health and safety for the period of extended operation of nuclear power plants."
  - Given that design CUFs are conservative when compared to actual, and that crack initiation is expected to occur when the actual CUF reaches 1.0, not 0.1 - there is no reason related to public health and safety to treat the postulated line break location as a TLAA.

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Pipe Break Criteria

- **SNC's position (Continued)**
  - Criterion 2 for a TLAA states: *Consider the effects of aging;*

    Fatigue is not an aging effect. Fatigue is an aging mechanism that manifests itself (i.e. the effect) as cracking. In addressing fatigue as an issue requiring management, the NRC limit is based on a CUF=1.0, which is the point where *cracking* is assumed to occur. It is not reasonable to assume cracking will occur at a CUF=0.1, especially recognizing that the design CUF is conservative when compared to the actual. Therefore there is no aging effect being managed and the screening criterion for a TLAA is not satified.

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Pipe Break Criteria

- **Conclusions:**
  - In closure of GSI-190, the staff determined that safety significance of metal fatigue was low and no generic regulatory action was warranted.
  - The line-break criteria of CUF=0.1 is a factor of 10 less than theoretical fatigue crack initiation and is thus even less significant from a safety perspective, especially in light of design conservatism.
  - MEB 3-1 was a screening criterion that has been met and safety purposes accomplished.
  - The concept of postulating line-breaks as components reach a CUF=0.1 fails to meet criterion required for a TLAA.
  - Therefore, this item is not a TLAA and the open item should be closed.

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